Integrated Resource Plan

NOVEMBER 2016

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Acronyms

Agency/Entity/Term	Acronym
21st Conference of the Parties (COP21)	COP21
Advanced Metering Infrastructure	AMI
Alternating Current	AC
Alternative Compliance Payment	ACP
American Recovery and Reinvestment Act	ARRA
American Wind Energy Association	AWEA
Annual Energy Outlook (EIA)	AEO
Automated Generation Control	AGC
Available transmission capacity	ATC
Balancing Area Authority	BAA
Balancing Authority	BA
Battery Energy Storage System	BESS
Berkley Research Group	BRG
Best Available Retrofit Technology	BART
Black and Veatch	B&V
Bonneville Power Administration	BPA
Bureau of Land Management	BLM
California Independent System Operator	CAISO
Carbon Dioxide	CO2
Citizen's Utility Board	CUB
Clean Air Act	CAA
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Clean Power Plan	CPP
Clean Power Research	CPR
Combined heat and power	CHP
Combined-cycle combustion turbine	CCCT
Combustion turbine	CT
Compressed air energy storage	CAES
Conservation Voltage Reduction	CVR
Cooling Degree Day	CDD

Agency/Entity/Term	Acronym
Cost of Service	COS
Data Request or Data Response	DR
Demand Response	DR
Department of Environmental Quality (Oregon)	DEQ
Department of Justice	DOJ
Direct load control	DLC
Dispatchable Standby Generation	DSG
Distributed Generation	DG
Dynamic Dispatch Program	DDP
Dynamic Transfer (Transmission) Capability	DTC
Electric Generating Unit	EGU
Electric Power Research Institute	EPRI
Emission Rate Credit	ERC
Endangered Species Act	ESA
Energy and Environmental Economics, Inc.	E3
Energy Efficiency	EE
Energy Facility Siting Council (Oregon)	EFSC
Energy Imbalance Market	EIM
Energy Information Services	EIS
Energy Services Supplier	ESS
Energy Trust of Oregon	Energy Trust
Engineered Geothermal System	EGS
Environmental Protection Agency (U.S.)	EPA
Environmental Quality Commission	EQC
Expected Unserved Energy	EUE
Federal Energy Regulatory Commission	FERC
Floating Surface Collector	FSC
Heating Degree Day	HDD
House Bill	HB
Idaho Power Company	IPC
Industrial Customers of Northwest Utilities	ICNU
Integrated Resource Plan	IRP
Internal Revenue Service	IRS

Agency/Entity/Term	Acronym
International Swaps & Derivatives Association	ISDA
Investment Tax Credit	ITC
Investor Owned Utility	IOU
Kilowatt	KW
Kilowatt hour	KWh
Megawatt	MW
Megawatt Average	MWa
Mid-Columbia	Mid-C
Mid-Term Strategy	MTS
Miscellaneous	Misc.
National Renewable Energy Laboratory	NREL
New Source Complement	NSC
North American Electric Reliability Corporation	NERC
Northwest Energy Coalition	NWEC
Northwest Gas Association	NGA
Northwest Intermountain Power Producers Coalition	NIPPC
Northwest Natural	NWN
Notice of Alleged Violation	NOAV
Notice of Proposed Rulemaking	NOPR
Occupational Safety and Health Administration	OSHA
Open Access Same-time Information System	OASIS
Open Access Transmission Tariff	OATT
Operation and Maintenance	O&M
Oregon Clean Electricity and Coal Transition Plan	OCEP
Oregon Department of Energy	ODOE
Oregon Department of Transportation	ODOT
Oregon Office of Economic Analysis	OEA
Oregon Public Utility Commission	OPUC
Oregon State Bar	OSB
Pacific Northwest Utilities Conference Committee	PNUCC
PacifiCorp, dba Pacific Power	PAC
People's / Public Utility District	PUD
Photovoltaic	PV

Agency/Entity/Term	Acronym
Polychlorinated biphenyl	PCB
Portland General Electric Company	PGE (or the Company)
Portland Public Schools	PPS
Power Cost Adjustment Mechanism	PCAM
Production Tax Credit	PTC
Qualifying Facility	QF
Renewable Development Fund	RDF
Renewable Energy Capacity Planning	RECAP
Renewable Energy Certificate	REC
Renewable Portfolio Standards	RPS
Request For Proposals	RFP
Securities & Exchange Commission	SEC
Senate Bill	SB
U.S. Energy Information Agency	EIA
United Nations Framework Convention on Climate Change	UNFCCC
United States Department of Energy	USDOE
United States Fish and Wildlife Service	USFWS
United States Forest Service	USFS
Western Canadian Sedimentary Basin	WCSB
Western Electricity Coordinating Council	WECC
World Trade Center	WTC

Our goal is to be our customers' trusted energy partner, meeting their need for safe, reliable, affordable electricity at home and in their businesses with increasingly sustainable energy solutions.

PGE's integrated resource plans have always offered detailed technical analyses of our strategy for supplying the electric power our customers need. The analysis is an invaluable tool to help PGE, our regulators and our stakeholders evaluate the choices available to us, both near and long-term, as we strive to find the least cost, least risk path for delivery of reliable power while reflecting our customers' values and complying with public policy and regulatory mandates.

This IRP reflects an ongoing evolution of our efforts to continuously improve. In this plan, you'll see that we're adapting to changing policy as we look to Oregon's energy future.

In no small part, this is driven by the adoption of the 2016 Oregon Clean Electricity Plan. PGE was part of the diverse coalition of utilities, customer groups, and advocacy organizations that helped develop and support passage of the legislation. The OCEP puts us on a path to achieve the state's goals for carbon emissions reductions in the electricity sector by requiring us to serve 50 percent of our customers' demand for electricity from qualifying renewable resources by 2040 and eliminate coal from our customer energy mix by 2035.

The OCEP also reflects the direction we've seen unfolding for at least a decade, as concerns around global warming and other environmental issues have intensified. In 2006, PGE acknowledged that the utility industry needs to be part of the global warming solution and called for carbon regulation at the national level. In 2007, we joined with stakeholders to craft and support adoption of Oregon's original renewable energy standard. And, our acknowledged 2009 IRP incorporated the discontinuation of the operation of Boardman on coal by the end of 2020, taking a broader view of likely future costs and risks associated with a generating resource that not long ago was viewed as a low-cost choice.

So how has all of this driven adaptation in our IRP? In short, we've changed the focus from meeting projected demand for power with acquisition of conventional resources we know we can deploy today, to achieving a significantly more renewable resource mix for tomorrow, based on new technologies and ambitious goals we've agreed are a priority for the communities we serve.

This doesn't mean we've compromised our commitment to an IRP that is based upon the best data, careful analysis, and realistic, workable options available. The action plan in this 2016 IRP is still firmly grounded in the practical balance of least cost and least risk actions that will meet our customers' energy needs. It does mean we've lifted our long-term vision to take full advantage of new technologies and markets for a smarter, more renewable and more flexible generating portfolio and grid – and to create more active partnerships with our customers – so we can meet the mandates of the OCEP and fulfill our customers' expectations of us as a utility that is pursuing our shared goals and vision for Oregon's more sustainable energy future.

The IRP is still a complex, technical document and the action plan still reflects a defined set of executable actions. I hope as you review the IRP, you'll agree that we've kept customers and community at the heart of our commitment to provide safe, reliable, and sustainable electricity at an affordable price, both today and tomorrow.

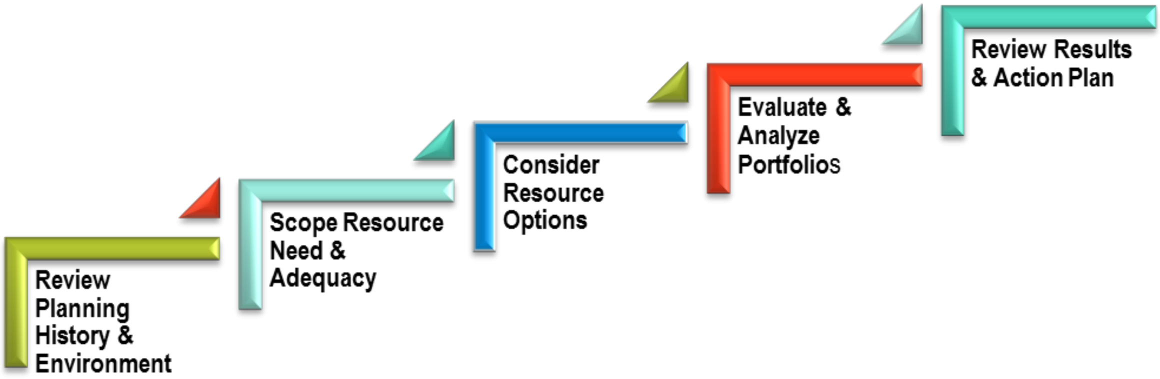
We thank everyone who participated in our public meetings and discussion during the development of the 2016 IRP, and look forward to a robust review of our conclusions and recommendations.

Sincerely,

Jim Piro

Jim Piro | President and Chief Executive Officer

Executive Summary



2016 IRP Executive Summary

Overview

Planning for a renewable, reliable, affordable energy future

The future of energy in Oregon, the nation and the world is undergoing dramatic change. As our state's population and economy continue to grow, so does the demand for energy. At the same time, PGE and its customers are committed to reducing greenhouse gas emissions that contribute to climate change.

The 2016 Integrated Resource Plan is a strategic road map that reflects a future focused on more renewable sources of energy and fewer carbon-producing resources. Our 2016 IRP also retains our essential focus on providing our customers with safe, reliable, and affordable energy, using increasingly sustainable energy solutions.

This IRP puts PGE on track for achieving the state's carbon greenhouse gas reduction goals for the electric power sector through at least 2040, and ahead of schedule for integrating additional renewables.

PGE was part of a diverse coalition of utilities, customer groups and advocacy organizations that developed Oregon's Clean Electricity and Coal Transition Plan (Senate Bill 1547), passed by state lawmakers in March of 2016. The law sets goals for increasing renewable resources and eliminating coal as an energy source for our customers. PGE embraces those goals.

Under the law, 50% of the energy PGE delivers to customers must come from qualifying renewable resources by 2040. Today, about 15 percent of our energy comes from qualifying renewables. To meet this aggressive timeline for renewable power expansion, and to take advantage of production tax credits to keep costs lower for our customers, the plan calls for adding 175 average megawatts of new renewable resources, which is equivalent to 515 MW nameplate of new wind resources.

The new law also transitions Oregon off coal-fired electricity. The Oregon Public Utility Commission (Commission) previously acknowledged PGE's plans to stop burning coal at our Boardman Plant by year-end 2020. Under the new law, PGE will stop using any coal resources to serve our customers no later than 2035. This IRP, and future IRPs to follow, will address strategies for filling the shortfall created by this transition, increasingly using renewables to do so.

Planning Process

The 2016 IRP uses new approaches and considerably more planning complexity to tackle challenging questions regarding the future of PGE's power supply. It is responsive to valuable recommendations we received from stakeholders following the 2013 IRP planning process, many of which challenged established thinking and required new analytical techniques.

PGE is committed to building stakeholder trust in its analysis and recommendations. We have been meeting with stakeholders for the past 18 months to discuss the strategies outlined in this IRP. This plan addresses their input, either by incorporating changes or providing more information to respond to questions, concerns, and suggestions.

This commitment to sharing information and building trust does not start and end with the 2016 IRP, but is integral to PGE's business. Just as the 2016 IRP has built off the recommendations and environment changes from the 2013 IRP, future IRPs will continue to benefit from a shared desire to continuously improve.

In order to better assess needs and capabilities for a system with more variable resources, PGE updated its modeling methodologies for determining capacity need and resource capacity contribution. The Company now bases its capacity need assessment on a robust reliability-based model, using an industry-standard loss of load expectation (LOLE) target. For all resource types, PGE uses the same model for estimating the capacity contribution of incremental resources to capture variability, correlation with load, benefits of locational diversity, portfolio effects, and declining marginal value.

Integrating the next generation of resources requires another evolution of planning processes and methods. As demand response and energy storage increase in scale and maturity, PGE is proactively developing ways to incorporate innovations into its integrated resource planning framework. As a leader in this effort, PGE continues to implement tools that improve our responsiveness to change, while allowing decisions to be made today based on the best available information to support resource decisions necessary to meet customers' long-term needs.

Scenario and Portfolio Analysis

Scenario analysis provides the framework for assessing the economic risks associated with the different portfolios. Commission guidelines state the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.[1]

As a result of its scenario analysis, PGE identified one portfolio, called the Efficient Capacity 2021 portfolio, as the Preferred Portfolio. The Preferred Portfolio represents the set of resources that provides the best combination of expected cost and risk for PGE and its customers under the assumptions used in the modeling. However, any plan faces uncertainty and the Preferred Portfolio is not a pre-determined course of action. Alternative portfolio strategies may prove cost effective in future procurement analysis. In fact, four of the top-ranked portfolios had relatively comparable performance to one another. The precise resources modeled in the 2016 IRP will not be the exact resources available in the market at the time of acquisition, nor will they be offered at the same prices assumed in the modeling.

Action Plan

The Action Plan in the 2016 IRP projects significant increases in energy efficiency, customer-side demand response, and renewable energy. As it does today, PGE will prioritize the implementation and dispatch of these sources before other generating resources.

Still, PGE will have a significant and growing gap between the power capacity needed to meet our customers' needs reliably and the resources available to do so. Much of the deficit is due to the

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[1] Commission Order No. 07-047.

need to generate power when renewable resources are unavailable, continued load growth, expiring long-term power purchase agreements, and ceasing coal-fired operations at Boardman.

Given PGE's obligation to reliably meet customers' needs, this IRP calls for a strategic use of new or existing dispatchable resources to complement and enhance our ability to add more renewable resources. New technologies give these plants the capability to quickly turn on and off to support the variability of renewable generation.

PGE has submitted an Action Plan that adheres to the Commission's procedural and substantive IRP Guidelines and complies with the requests and directives that the Commission issued in its order acknowledging PGE's 2013 IRP (see Appendix A, Compliance with the Commission's IRP Guidelines, and Appendix B, PGE's Compliance with 2013 IRP Order (Order 14-415)). After testing diverse portfolios under alternative projections, PGE is confident that the recommended Action Plan provides for the best combination of expected costs and associated risks, while retaining the flexibility to take advantage of market-driven resource innovations. It provides PGE the best opportunity to deliver safe, reliable and affordable energy to our customers in an increasingly sustainable way. The Action Plan takes full advantage of technologies and markets to enable a smarter, greener, more flexible generating portfolio and distribution system.

Load Growth

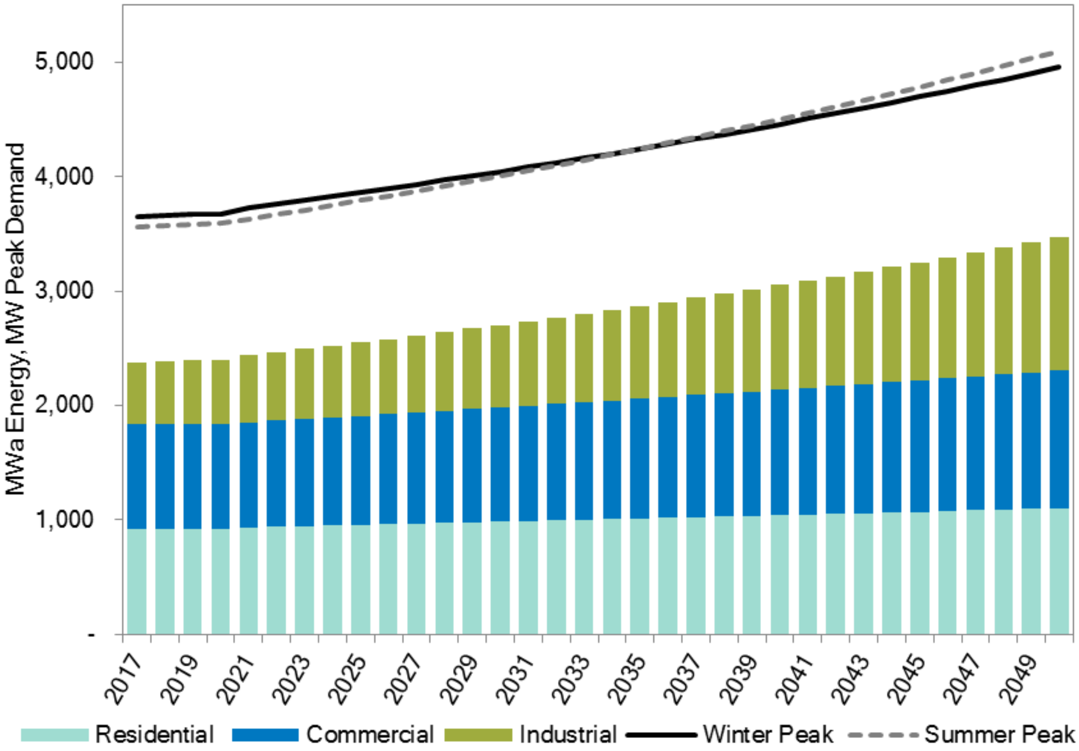
Oregon's economy is a key driver of load growth projections. The state's economy has continued to improve since the filing of the last IRP, with employment surpassing pre-recession peaks and reaching growth rates over 3%. PGE's industrial sector performance and strong in-migration also have driven load growth projections above national averages.

In the short-term (2017 to 2021), PGE's load growth reflects the pace of economic growth in Oregon as forecast by the Oregon Office of Economic Analysis (OEA). It also reflects expansions currently underway among certain large customers. The long-term outlook for future economic, population and load growth in Oregon and PGE's service territory is also positive.

Energy efficiency and demand response have contributed significantly to reducing load growth. In recent years, PGE estimates that energy efficiency has reduced its deliveries approximately 1.5% per year.

The chart below shows PGE's projected load growth – 1.2% per year – when energy efficiency and demand response have been factored in.

FIGURE ES-1: Reference case forecast by class: 2017 to 2050



A detailed discussion of the load forecast and methodology is provided in Section 4.1, Load Forecast.

Resource Needs

A key objective of the IRP process is to identify the gaps between existing resources and additional resources needed to achieve a sustainable, reliable and affordable energy future.

Our first task in assessing resource needs is to identify the contribution that energy efficiency and demand response can make.

Adding energy efficiency — minimum of 135 MWa

Energy efficiency is a top priority resource in our portfolio planning, and it is the first resource PGE turns to for meeting customer needs. PGE is committed to helping our customers reduce their energy use, and we have a long history of working with the Energy Trust of Oregon to identify and acquire all available cost-effective energy efficiency measures. Through the combined efforts of the Energy Trust, customers and utilities, Oregon is a national leader in capturing energy efficiency.

From 2017 through year-end 2020, PGE plans an additional 135 MWa of EE savings on top of what has already been achieved, with continued EE growth in later years.

Energy efficiency is discussed in detail in Section 6.1, Energy Efficiency.

Adding demand response — 77 MW

Demand response (DR) is another important way customers can help reduce PGE's resource need by reducing peak customer demand. Demand response will be an important part of PGE's total resource portfolio as we move to greater use of renewable resources.

Beyond PGE's own efforts in recent years to increase use of DR in our service territory, Senate Bill 1547 authorizes the OPUC to direct utilities to plan for and acquire cost-effective DR. PGE hired the Brattle Group to complete a comprehensive DR potential study. This study was used to develop an aggressive but attainable goal for DR acquisitions used in this IRP. These goals will be achieved through a diverse set of programs that target residential, commercial, and industrial customers. PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years.

Section 6.3, Demand Response, provides information about PGE's DR programs and the DR potential study.

Adding renewables to meet Oregon's 50% RPS requirement — 175 MWa

As the annual requirement for renewable energy increases from the current 15% to 50% in 2040, PGE will need to significantly expand its portfolio of RPS-compliant resources. RPS-compliant renewable resources can be in the form of energy production, Renewable Energy Credits (RECs), or both.

This IRP contains a robust analysis of all options for compliance, including the advantage of taking early action on physical compliance to secure tax credits and manage the use of unbundled RECs. The analysis shows that acting early, ahead of RPS requirements, is in the best interest of customers. For this reason the Action Plan calls for the addition of 175 MWa of new renewables (equivalent to 515 MW nameplate of new wind resources). The Company's strategy for complying with the RPS obligations is discussed in Section 10.6, RPS Compliance Strategies.

Even after capturing all available cost-effective energy efficiency measures, expanding the DR program, and making large renewable additions, PGE faces a deficit in resources to meet customer needs. As customers' energy use continues to grow, existing generation resource contracts expire, renewable requirements increase and coal resources are phased out, PGE's will need to add resources to maintain reliability.

Adding annual dispatchable resources — 375-550 MW

With increasing reliance on renewable generation, PGE faces potential challenges in maintaining enough flexibility to adequately balance renewables and meet customer energy demands in the future. A thorough comparison of the performance of various flexible technology options is presented in Section 5.3, Flexible Capacity. PGE proposes pursuing acquisition of 375 to 550 MW of long-term annual dispatchable resources.

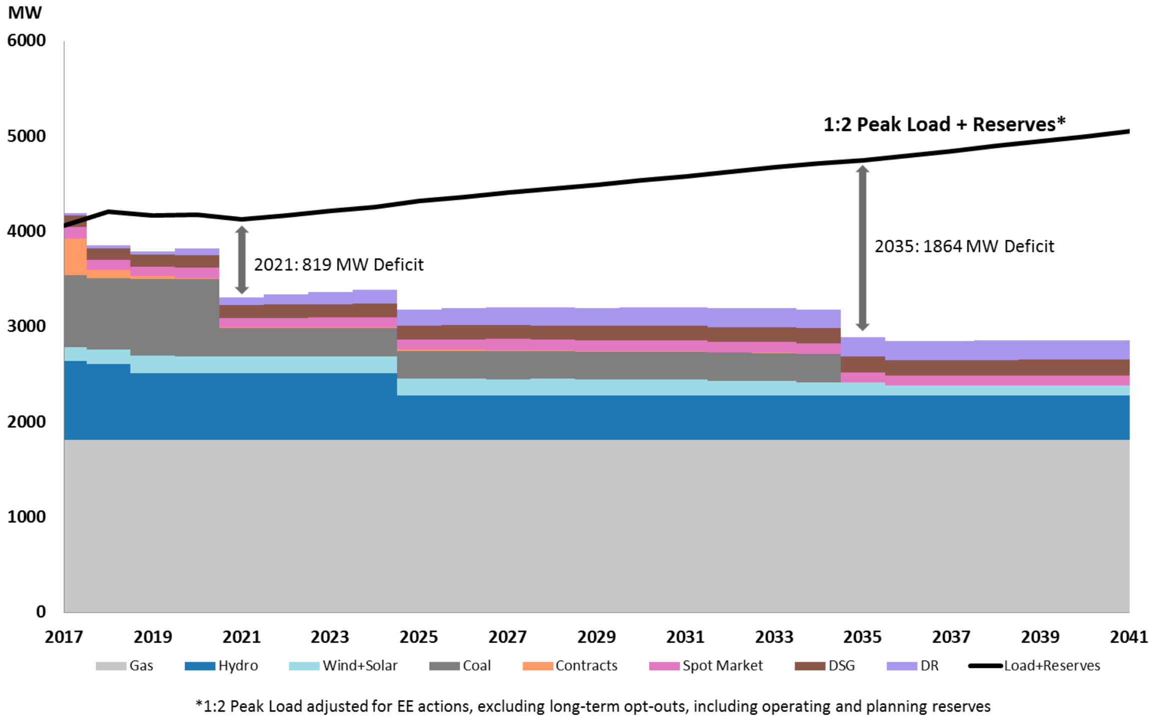
Adding annual or seasonal capacity resources — up to 400 MW

Achieving high standards for providing reliable service to customers and meeting regional reliability requirements are critical priorities for PGE. PGE will consider a mix of annual and seasonal resources to fill the remaining capacity need.

In 2021, after Boardman ceases coal-fired operations, PGE's capacity deficit is 819 MW. Figure ES-2 provides a summary of the capacity deficit from 2017 through 2041.

The capacity adequacy study is discussed in Section 5.1, Capacity Adequacy and Capacity Contribution.

FIGURE ES-2: PGE's estimated annual capacity need



Scenario Analysis

Methodology

PGE designed 23 portfolios to consider various resource strategy questions (e.g., RPS compliance timing) and to identify a Preferred Portfolio. PGE then evaluated the total cost of meeting customer demand with each portfolio under reference case assumptions, yielding the primary cost metric used throughout the IRP. To evaluate the price risks to customers, PGE also designed 23 potential future environments in which key variables deviate from their reference forecasts. These key variables include fuel prices, carbon prices, load growth, capital costs, hydro availability, and renewable resource performance. Risk metrics were designed to characterize variability (how much the cost may swing due to uncertain conditions), severity (how high costs may rise under worst case assumptions), and durability (how consistently well or poorly a portfolio performs relative to the other portfolios across the futures). These metrics are described in Chapter 11, Scoring Metrics.

Guiding Principles

To meet future resource needs, PGE designed candidate resource portfolios and developed a methodology for evaluating these portfolios with four factors in mind: Policy, Reliability, Technology, and Price.

Policy — PGE designed all portfolios to comply with existing state and federal regulations, including the Clean Power Plan (CPP) and SB 1547. In addition, portfolio evaluation incorporated the impact of renewable policies in other states on the performance of PGE's resources and the projected impact of the CPP on carbon prices. See Chapter 3, Planning Environment, for more information.

Reliability — PGE designed portfolios to meet a reliability target that ensures a loss of load probability not exceeding one day in 10 years and to meet a flexibility requirement of approximately 400 MW of dispatchable resources to accommodate the variability and uncertainty of renewable resources on the system. Reliability requirements are discussed in Chapter 5, Resource Adequacy.

Technology — PGE included a diverse set of technologies in portfolio analysis, including demand-side resources like energy efficiency, demand response, dispatchable standby generation, and supply-side resources like large-scale wind, solar, biomass, geothermal, and natural gas. These resources are discussed in Chapter 6, Demand Options, and Chapter 7, Supply Options. In addition, PGE undertook more detailed studies of emerging technology potential and value, including energy storage and demand response, to inform both the current and future IRPs. These studies can be found in Chapter 6, Demand Options, Chapter 8, Energy Storage, and Appendix I, Demand Response Programs, respectively.

Price — PGE's evaluation prioritized the need to meet customer's demands at low cost and low risk should future conditions evolve differently than currently anticipated. This least-cost, least-risk framework is the foundation of the portfolio evaluation methodology, and is discussed further in Chapter 10, Modeling Methodology.

Key Findings

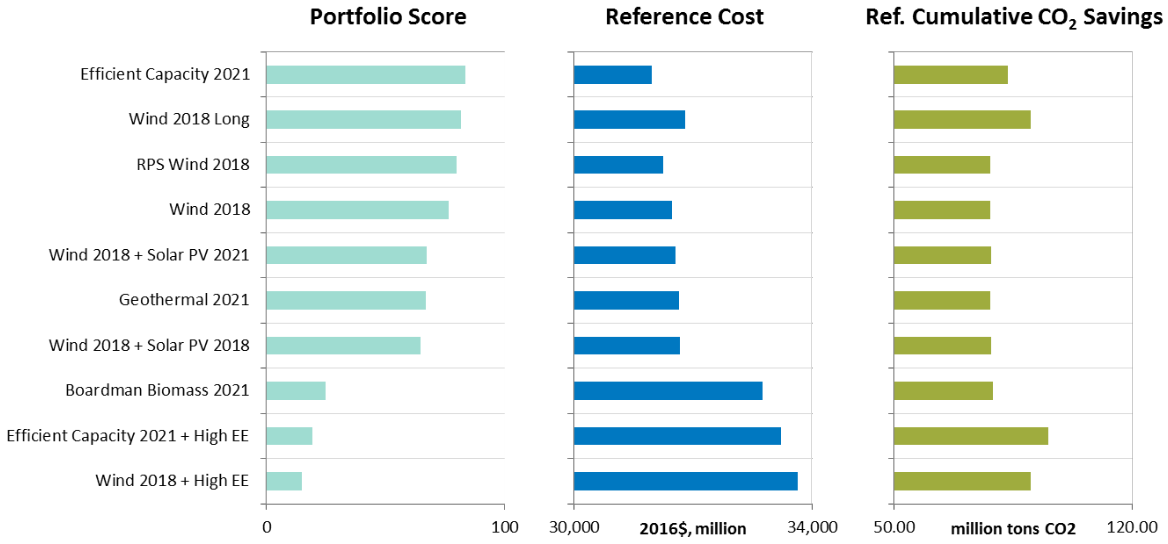
1. All actionable portfolios incorporate the same levels of demand response, conservation voltage reduction, and dispatchable standby generation and include, at a minimum, all cost-effective energy efficiency identified by the Energy Trust.

2. Acquiring a greater quantity resources that qualify for the Production Tax Credit reduces costs to customers, and capturing more of the PTC, by acquiring physical resources earlier, is more affordable than deferring an RPS build to 2025.

3. All actionable portfolios include procurement of flexible resources to meet the capacity need that remains after accounting for the capacity contributions of the renewable, conventional, and energy efficiency resources incorporated into each portfolio.

4. Portfolios that include cost-effective EE and renewable resources to meet RPS requirements, along with highly efficient flexible generation, perform relatively better than other candidate portfolios, as shown in the chart below.

FIGURE ES-3: Performance of actionable portfolios



Recommended Action Plan

The Preferred Portfolio forms the basis for the recommendations put forward in the Action Plan. The Company's analysis has led to the development of a plan that consists of diverse resources which, when integrated with PGE's existing portfolio, offer a balance of cost and risk and a strategy for PGE to reliably and adequately serve customers into the future while meeting our sustainability goals.

Consistent with the Commission's IRP Guidelines, PGE plans to undertake the major activities of resource procurement in the next two to four years, or by 2020. In addition, planning considerations beyond 2020 also inform the Action Plan, such as the Oregon law requiring 50% renewables by 2040.

The Action Plan allows PGE to effectively respond to continued load growth, increasing system variability, and existing resource expirations. The Company will complete its resource acquisitions through a combination of actions related to both existing and new resources. The Action Plan spans diverse technologies in three categories of resource actions: demand-side, supply-side, and integration.

More specifically, demand-side actions include continuing the support of cost-effective energy efficiency and pursuing Demand Response and Conservation Voltage Reduction programs. Supply-side actions include RPS compliant renewable resources, capacity resources (both annual and seasonal) and Dispatchable Standby Generation. In addition, PGE will attempt to renew expiring hydro contracts and plans to submit a proposal for the development of energy storage systems. To inform the next IRP or IRP Update, PGE also suggests Enabling Studies in the Action Plan. The key elements of the Action Plan are discussed in the following sections.

Demand-side Actions

Energy Efficiency

PGE supports deployment of cost-effective energy efficiency by the Energy Trust of Oregon (Energy Trust) targeting the addition of 135 MWa (176 MW[2]) from 2017 through 2020.

Demand Response

PGE will pursue the acquisition of Demand Response (DR) targeting the capacity addition of 77 MW (winter) and 69 MW (summer) through 2020.

Conservation Voltage Reduction

PGE will pursue programmatic Conservation Voltage Reduction (CVR) deployment, targeting minimum energy savings of 1 MWa through 2020. To enable that conversion, PGE is pursuing smart meter voltage data bandwidth expansion and data analytics research and development efforts to support system-wide expansion of a dynamic CVR program.

Supply-side Actions

Renewable Resources

PGE intends to issue one or more Requests for Proposals (RFPs) for approximately 175 MWa (equivalent to 515 MW nameplate of wind generation) of bundled RPS-compliant renewable resources (energy and RECs), and/or Renewable Energy Certificates (RECs), with a preference for maximizing available federal incentives (such as sec 45 Production Tax Credit) for the benefit of customers.

Standby Resources

PGE will pursue expansion of Dispatchable Standby Generation (DSG) by 16 MW to meet standby capacity needs (non-spin). PGE will also pursue actions (such as customer site development and contract negotiation) to achieve additional annual standby targets, if needed beyond 2020.

Hydro Contract Renewals

PGE will pursue the renewal, or partial renewal, of expiring hydro contracts, and if cost-effective contract terms are available, acquire them for customers.

Energy Resources

PGE will assess the energy value brought by RPS or capacity resources through the RFP process and capture the merits of high capacity factor resources through reduced exposure to the market.

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[2] Gross value at busbar.

Capacity Resources

PGE's capacity need in 2021, after actions for EE, DR, CVR and DSG, and accounting for imports and executed Qualifying Facility (QF) contracts[3] that are not yet online, is approximately 819 MW.[4]

PGE will issue one or more RFPs to acquire up to 850 MW of capacity that could be a mix of annual and seasonal resources. PGE may also enter into short and/or mid-term contracts (e.g., 2-5 years) to maintain resource adequacy between the time the capacity is needed and the time in which resources can be acquired through an RFP. Of the up to 850 MW, and in alignment with the Preferred Portfolio, PGE proposes pursuing acquisition of 375 to 550 MW of long-term annual dispatchable resources and up to 400 MW[5] of term-limited annual (or seasonal equivalent) capacity resources.

Integration Actions

Energy Storage

Pursuant to House Bill (HB) 2193, and not later than January 1, 2018, PGE will submit one or more proposals to the Commission for developing a project that includes one or more energy storage systems that have the capacity to store at least 5 megawatt hours of energy.

Enabling Studies

Enabling studies provide useful research actions to inform the next IRP. PGE proposes several enabling studies to evaluate:

- The treatment of market capacity
- Continued flexibility and curtailment metrics
- Customer insights
- Others as identified.

PGE will work with stakeholders to develop appropriate scopes of study for these enabling studies.

Conclusion

For decades, American electric utilities have provided the energy systems and infrastructure that underpin the nation's economy. PGE has been part of that history since the Company began serving customers in 1889 with the first long-distance transmission line in the country. This 12-mile line – a connection from Willamette Falls to downtown Portland – started the one-way streamflow of electricity on the Company's system to the customer. Accordingly, PGE evaluated resources in a linear fashion, individually considering generation, transmission, and distribution.

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[3] Some Qualifying Facilities are in early stage development and are at increased risk for delay or cancellation. PGE's capacity need will be greater if QF's under contract fail to come on line as planned.

[4] Annual capacity value.

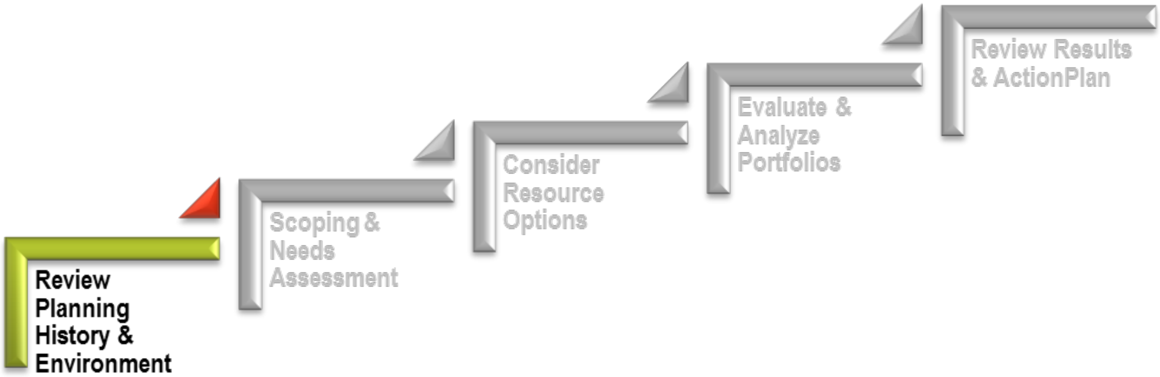
[5] Quantity subject to change based on incremental acquisitions: renewable acquisitions, contract execution, etc. Seasonal capacity products have capacity contribution values of less than 100%. For example, a contract for 300 MW of summer and winter capacity (July-September, December-February, On-peak hours) is equivalent to approximately 240 MW of an annual resource. See Chapter 5, Resource Adequacy, for additional discussion.

Since energizing that first major innovation, PGE has continuously made advances that influence the generation, transmission, and consumption of power in Oregon and the region.

Today, PGE’s commitment to innovation continues as the Company incorporates current technological development with the evolution of the integrated grid in resource planning.

PGE is committed to serving our customers and being their trusted energy partner. The 2016 IRP delivers on that commitment by offering detailed technical analyses of the options for supplying the electric power our customers need. This IRP represents a continuous evolution of PGE's IRP process, which incorporates changes in local, regional, and national planning environments, and adapts to shifts in Oregon's energy future. Comprehensive scenario analysis captures the effects of various potential future states of the world. Combining information from the analysis with the broad experience and expertise of PGE and stakeholders, the Action Plan balances cost and risk measures, and takes full advantage of technologies and markets to enable a smarter, greener, more flexible generating portfolio and distribution system.

Part I. Planning History and IRP Process



CHAPTER 1. Planning History

PGE has a strong integrated resource planning history. For over 20 years, PGE has constructed IRPs that properly consider past trends, make long-term projections for the next 20-30 years, and provide a clear and flexible roadmap for future resource needs. With the help of multiple internal and external stakeholders, the 2016 IRP continues in that tradition.

To orient stakeholders to the plans set forth in this IRP, this Chapter provides a snapshot of PGE's current status as Oregon's primary energy provider and a brief look at critical decisions from the 2009 and 2013 IRPs, all of which set the stage for the 2016 IRP and Action Plan.

Chapter Highlights

- ★ **PGE is working to integrate sustainability in every aspect of its business, particularly in the Company's relationship with its four key stakeholder groups: customers, shareholders, community, and employees.**
- ★ **Energy efficiency, renewables, and the declining coal share in PGE's customers' resource mix, greatly reduce the Company's CO_2 "footprint" over time.**
- ★ **PGE has actively engaged its stakeholders in the preparation of its 2016 IRP by conducting nine public meetings or roundtables, participating in two meetings with the Commissioners of the Public Utility Commission of Oregon (OPUC), and providing responses to over 100 parking lot or feedback questions from stakeholders.**
- ★ **PGE continues to participate in key regional energy planning forums.**

1.1 PGE Today

PGE is Oregon's largest energy company, serving over 840,000 customers in seven counties. The Company's service territory spans 4,000 square miles, allowing it to deliver over one-third of the electricity consumed annually in the state of Oregon. As a leader in Oregon, PGE works collaboratively with the OPUC, customer advocacy groups, and other stakeholders to provide electric service in a safe, sustainable and reliable manner, while providing excellent service at a reasonable price. To maintain this level of service, PGE utilizes a diverse mix of generation resources, including wind, solar, thermal, and hydroelectricity, as discussed more thoroughly in Part III, Resource Options, and Appendix D, Existing Resources. Below, Table 1-1 provides a current, summary look at PGE, its customers, and the demand for power within the Company's service area, while Figure 1-1 provides a map of the Oregon communities PGE currently serves.

TABLE 1-1: PGE quick facts

Population of service area	1,800,000
State-approved service area (square miles)	4,000
Cities served	52
Average number of retail customers	848,452
Residential	742,467
Commercial	105,802
Industrial	255
Megawatt-hours delivered (retail and direct access)*	19,382,000
Average annual kilowatt-hours per residential customer	9,866
Average annual revenue per residential customer	$1,139
Residential price per kilowatt-hour	11.55 cents
National residential average price per kilowatt-hour	12.56 cents
2014 peak load (Feb. 6, 2014)	3,914 MW
All-time peak load (Dec. 21, 1998)	4,073 MW

*Figures based on year-end 2015 calendar data.

FIGURE 1-1: PGE service territory

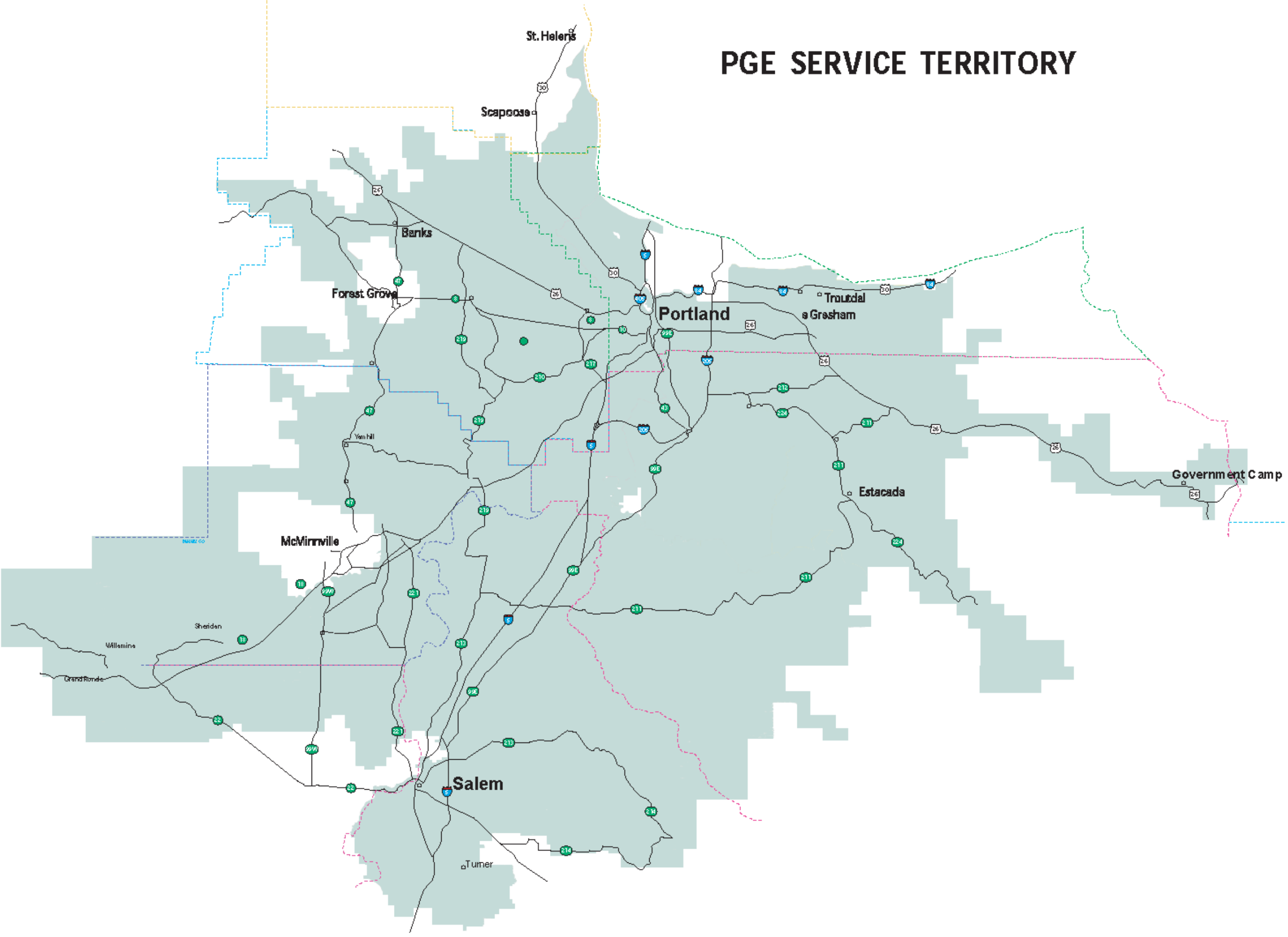
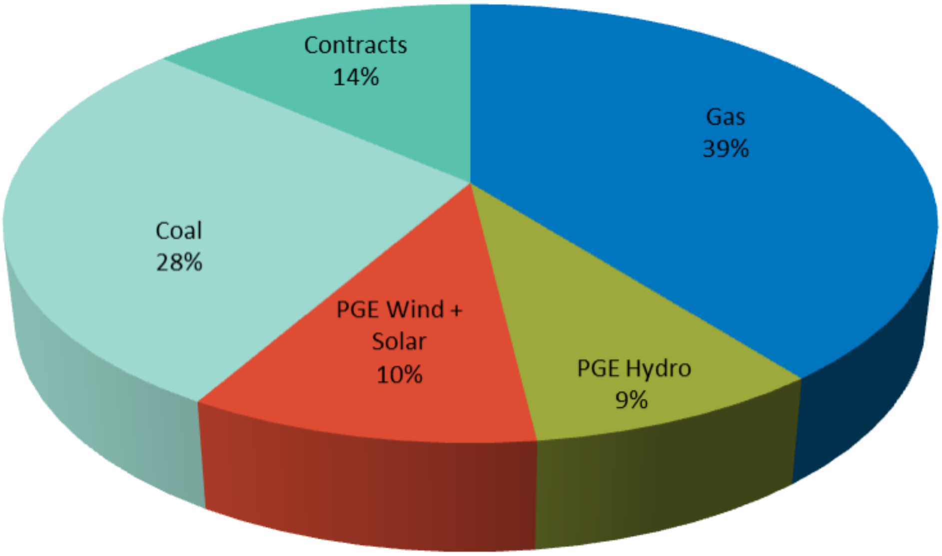


Figure 1-2 shows annual average energy availability of PGE's 2017 resource mix (before any economic dispatch). The Contracts portion includes contracted hydro, wind, and solar resources. The figure does not include energy efficiency (EE), as PGE accounts for EE in its load forecast. Appendix D, Existing Resources, provides descriptions of PGE's existing resources and contracts.

FIGURE 1-2: PGE's 2017 average annual energy resource mix (availability)



1.2 Prior Planning Efforts

With each IRP, PGE takes the opportunity to examine the assumptions made in prior IRPs and determine which assumptions, if any, changed and require updating. Whether it is changes in demand, fuel costs, or market assumptions, each IRP provides the Company the opportunity to reassess its long-term plans and resource mix. PGE begins this reassessment with a look back at prior IRPs, which provide essential information for the development of current and future IRPs, including the identification of areas for future studies.

1.2.1 2009 IRP

In the 2009 IRP, PGE’s analyses identified the need for several new resources.

PGE also highlighted the need for new resources to:

- Maintain system reliability given:
  - PGE's reduced access to hydro, traditionally used to meet peaking needs;
  - PGE's increased reliance on non-dispatchable and intermittent renewable resources; and
  - PGE’s growing summer peak loads combined with the overall summer peaking nature of the Western Electricity Coordinating Council (WECC) region, particularly when the WECC is prone to supply shortages in summer.
- Meet the 2015 Renewable Portfolio Standard (RPS) target.
- Potentially phase out the Boardman plant's coal operation, given the then new Oregon Regional Haze Plan and Oregon Utility Mercury Rule requirements. These restrictive rules caused PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing coal-fired operations.

Ultimately, PGE's 2009 IRP Action Plan proposed to:

- Acquire over 650 MW of gas-fueled thermal plants.
- Acquire 500-600 MW of EE, renewables, demand response (DR), and dispatchable standby generation (DSG).
- Fill the remaining peaking need with long and short-term seasonal contracts.

Additionally, PGE studied the expansion of the transmission system in the Pacific Northwest and the possibility of relieving congestion in the area by building a new line—Cascade Crossing. PGE explored the possibility of building Cascade Crossing, but has indefinitely suspended the project.

1.2.1.1 Commitment to Cease Coal-Fired Operations at Boardman

During the 2009 planning cycle, PGE worked cooperatively with stakeholders and proposed an emission control and operating plan for Boardman to comply with both the federal Regional Haze Best Available Retrofit Technology (BART) requirements and the Oregon Utility Mercury Rule standards. PGE proposed to install emissions abating technologies for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and mercury in order to continue coal operations at Boardman through 2020 and cease coal operations after such date.

In the 2009 IRP acknowledgement order, (Order No. 10-457) the OPUC acknowledged PGE's proposal, also known as the Boardman 2020 plan. The OPUC's acknowledgment was conditional and subject to the Environmental Quality Commission's (EQC) approval of the Boardman 2020 plan. EQC granted approval and PGE proceeded to prepare for the cessation of coal operation by the end of 2020; postponing, however, any decision on how to replace Boardman until the 2016 IRP.

PGE's historical decision to voluntarily cease coal-fired operation at Boardman, the only coal plant operating in Oregon, is further validated by the recent passage and signing into law of SB 1547. More discussion on SB 1547 and the impact on PGE's 2016 IRP proposed resource strategy is available in Section 3.1.1, Oregon Clean Electricity & Coal Transition Plan (SB 1547). Additionally, Chapter 12, Modeling Results, discusses PGE's SB 1547 compliance strategies.

1.2.1.2 The Competitive Bidding Process (2012 RFP)

Following the 2009 IRP acknowledgment, PGE issued requests for proposal (RFP) for renewables, baseload energy, flexible capacity, and seasonal capacity resources. PGE finalized the RFPs in 2013 and selected the following top performing bids:

- **Renewables.** Tucannon wind, approximately 267 MW, which came into service on December 15, 2014.

- **Energy baseload.** Carty Generating Station (Carty), approximately 440 MW[6] CCCT-G, which came into service on July 29, 2016.

- **Flexible capacity.** Port Westward 2, approximately 225 MW reciprocating engines, which came into service on December 30, 2014.

- **Seasonal capacity.** Five-year contracts for the summer and winter supply up to 100 MW of on-peak capacity.

1.2.2 2013 IRP

In the 2013 IRP, PGE did not propose any major action except for the ongoing procurement of demand-side resources and the renewal of expiring hydro contracts. Moreover, PGE was still in the process of procuring the resources selected in the 2009 IRP and the Company's expected incremental needs for 2017 (the action plan year) did not suggest near-term actions to support the need for long-term resource procurement.

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[6] Approximate net capacity, new and clean, 55° F ambient design temperature.

In accordance with the requirements of the 2009 IRP acknowledgment order, PGE completed or updated the following studies:

- Requirement and supply of dynamic capacity.
- Wind integration study.

1.2.2.1 Preferred Portfolio

The portfolio analysis in the 2013 IRP tested alternative strategies to address the cessation of Boardman coal operations in 2020. Following up on a commitment made in the 2009 IRP with regard to the Boardman 2020 plan, PGE worked with stakeholders and a consultant, Energy and Environmental Economics, Inc. (E3), to develop low-carbon portfolio alternatives.

PGE's 2013 IRP evaluated 18 candidate portfolios and identified the *Baseload Gas/RPS only* as the preferred portfolio.

The main features of the 2013 IRP preferred portfolio were to:

- Add all achievable and cost-effective EE identified by the Energy Trust of Oregon (Energy Trust).
- Pursue distributed generation (DG) and dispatchable standby generation (DSG) when economic in PGE's territory.
- Replace Boardman with a high efficiency combined cycle combustion turbine (CCCT).
- Procure renewables to meet the 2020 RPS and maintain physical compliance with RPS thereafter.

1.2.2.2 Action Plan

The identification of a preferred portfolio had no material consequences on the 2013 action plan, as most of the supply-side actions analyzed were after 2017. The OPUC acknowledged the need to proceed with demand-side resource procurement and approved PGE's plans to engage in several enabling studies that would inform subsequent IRPs (see sections below).

1.2.2.3 2013 IRP Update

PGE filed its informational 2013 IRP Update in December 2015. The document provided the Commission with an update on the status of various requirements identified in the 2013 IRP Action Plan, including the numerous studies designed to inform the 2016 IRP. Additionally, PGE revised its RPS compliance strategy, comparing a reliance of banked RECs to physical procurement by the 2020 RPS compliance date. Based on the results of this analysis, PGE concluded that reliance on a REC bank through 2023 and postponement of the acquisition of renewable resources after such date was the best strategy to balance cost and risk.

1.2.2.4 Results of Past Planning Efforts

Thanks to the above-described planning efforts, PGE currently has a diversified set of resources to meet customer's demand. More precisely:

- With the addition of Tucannon River and several wind and solar contracts, PGE's wind and solar fleet includes over 700 MW of installed capacity and meets more than 15% of demand.
- The successful renewal of hydro contracts allowed PGE to retain close to 1,100 MW of regional hydro resources generating, on average, electricity equal to over 15% of the total retail demand in 2015.
- PGE's 814 MW of coal plants are in compliance with all current regulations. In 2015, the Company's coal plants met over 20% of demand.
- Port Westward 2 increased PGE's total gas-fueled fleet to 1,371 MW, providing flexible capacity to accommodate load and renewable generation fluctuations. In 2015, PGE filled about 25% of its demand with gas plants. The completion of Carty in 2016 will increase PGE's total capacity to over 1,800 MW.

On the customer's side, PGE has procured all cost-effective EE identified by the Energy Trust and continues to actively engage customers in demand-response and distributed generation programs. Overall, PGE has met all economic, reliability, and environmental targets highlighted in past IRPs.

1.2.3 Planning Actions since 2013 IRP

The 2016 IRP is PGE's 33-year projection of future power needs and an assessment of how the Company will meet those needs. As in past IRPs, the 2016 IRP contains forecast load growth, analyses of technical and financial issues, and an analysis of the various resource options available to meet the Company's resource needs. Included in the 2016 IRP are near-term and long-term actions that PGE will take in order to begin implementing the 2016 IRP Action Plan.

To develop the 2016 Action Plan, PGE performed critical enabling studies to help inform the 2016 IRP, evaluated its various sustainability actions since the 2013 IRP, and reviewed the results of the studies with stakeholders in over a year of planning meetings.

1.2.3.1 Studies to Inform 2016 IRP

Following acknowledgment of the 2013 IRP, PGE conducted multiple studies and research designed to inform the development of the 2016 IRP. These studies represent a major effort to enhance the Company's long-term models and improve modeling inputs.

Throughout the 2016 IRP public process, PGE shared the process for the development of these studies, as well as the results, with public stakeholders. This section provides a brief summary of each study.

Load Forecast Methodology

The penetration of new technologies coupled with demographic and industrial paradigm shifts affecting Oregon, prompted PGE to conduct a critical analysis of its load forecast methodology. In late 2014, PGE contracted Itron, an independent industry expert, to conduct a review of the Company's load forecast methodology. At the conclusion of this evaluation, Itron found PGE's methodology to be effectively consistent with industry standards. Itron also provided PGE recommendations to further align the Company's methodology and models with industry best practices. During the 2016 IRP public process, PGE discussed its load forecast methodology and results, along with the Itron findings, at four public meetings and technical workshops. Chapter 4, Resource Need, provides a more detailed discussion of the Itron study and PGE's updates to its load forecast modeling and methodology.

Planning Reserve Margin

The retirement of existing power plants combined with the increasing penetration of wind and solar in the Pacific Northwest is triggering reliability concerns. To better address these concerns, PGE engaged Energy + Environmental Economics, Inc. (E3) to complete a planning reserve margin and variable energy resource capacity contribution study. The study provides a statistical assessment of PGE's total resource portfolio and assesses the capacity need in 2021 to meet a resource adequacy target. E3 based the modeling on its publicly available Renewable Energy Capacity Planning model (RECAP). Chapter 5, Resource Adequacy, provides the final results from the study and a detailed discussion as to how PGE incorporated the results into the 2016 IRP.

Flexible Capacity

In 2014 and 2015, PGE engaged in significant work to examine its dynamic capacity needs, alternatives to addressing these needs, and tools to optimize the Company's mix of flexible capacity resources.

Through its Dynamic Dispatch Program (DDP), PGE completed engineering studies of the Company's existing resources to better determine: 1) their abilities to provide flexible capacity; and 2) the associated costs. PGE also installed hardware and software designed to improve the dynamic dispatch of its existing fleet. Finally, the Company integrated the DDP cost and flexibility performance information into the flexibility modeling for the 2016 IRP.

Additionally, PGE worked with E3 to conduct a flexibility capacity analysis of the Company's system with various combinations and amounts of new renewable resources and flexible capacity resources. The study used E3's stochastic production simulation model, REFLEX, to assess the performance and cost of each portfolio, providing information about potential additional flexibility need, by renewable resource type and penetration level, and the suitability of different capacity resources to provide that flexibility. Chapter 5, Resource Adequacy, provides the final results from the study and further discussion as to how PGE used the results in the 2016 IRP.

Distributed Generation

Distributed generation (DG) is a potential least cost way to provide peaking resources. However, in PGE's past IRPs, the Company lacked sufficient data to appropriately project the contribution of emerging DG technologies. To fill this void and in compliance with its 2013 IRP acknowledgement order, PGE conducted studies on the potential to expand the installation of cost-effective distributed generation (DG) for all DG resources, including combined heat and power (CHP) projects. PGE's research included a study on a methodology to assess the value of solar by Clean Power Research (CPR) and a market assessment by Black & Veatch (B&V) of DG solar and other DG resources, under the regulatory structures and incentives that were current at the time of the study. (See Appendix F, Distributed Generation Studies.)

The CPR study focused on assessing the value of DG solar to the energy grid and customers.[7] The B&V study focused on the potential deployment of solar and other DG technologies: 1) Non-Solar Distributed Generation Market Research;[8] and 2) Solar Generation Market Research.[9] The B&V reports examined the potential for DG solar and three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines.

Chapter 7, Supply Options, and Appendix F, Distributed Generation Studies provide greater details on the CPR and B&V studies, and how PGE intends to utilize the information obtained from these studies.

Demand Response Potential

To better inform its own DR initiatives and to establish inputs to its IRP process, PGE contracted with The Brattle Group to develop an updated DR potential study. The purpose of this study was to estimate the maximum system peak demand reduction capability that PGE could realistically achieve through the deployment of specific DR programs in its service territory under reasonable expectations about future market conditions. The study also assesses the likely cost-effectiveness of these programs. Chapter 6, Demand Options, offers additional information on the potential study, its recommendations, and the subsequent actions taken by PGE.

Energy Imbalance Market (EIM)

In the 2013 IRP, the Commission directed PGE to complete an energy imbalance market (EIM) analysis. In response to the Commission's direction, PGE compared the benefits of joining the Western EIM to that of the Northwest Power Pool MC Intra-Hour Energy Market. PGE contracted E3 to conduct this analysis. PGE and E3 completed the EIM analysis and submitted the Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options[10] report to the OPUC on November 6, 2015.

Since submitting the comparative analysis to the OPUC, PGE has made significant progress towards joining the Western EIM. First, PGE and the CAISO signed an Implementation Agreement, which the Federal Energy Regulatory Commission (FERC) accepted on January 19, 2016.[11] The Implementation Agreement identifies six project milestones that culminate in PGE's completion of the EIM System Deployment and Go-Live. PGE completed the first of these milestones, a detailed project

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[7] Benjamin Norris, "PGE Distributed Solar Valuation Methodology," Clean Power Research, July 13, 2015. *See* Appendix F, Distributed Generation Studies; *see also* https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/distributed-solar-valuation.pdf.

[8] Black & Veatch, "Non-Solar Distributed Generation Market Research," September 24, 2015. *See* Appendix F, Distributed Generation Studies; *see also* https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/non-solar_market_research.pdf.

[9] Black & Veatch, "Solar Generation Market Research," September 24, 2015. *See* Appendix F, Distributed Generation Studies; *see also* https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/solar_generation_market_research.pdf.

[10] See filing in Docket LC 56. PGE incorporates that report by reference in its 2016 IRP.

[11] California Independent System Operator. 154 FERC ¶ 61,020. January 19, 2016.

management plan, and is in the process of completing the second milestone, the Full Network Model Expansion.

Climate Change

Included in the 2016 IRP is an update of the climate change study conducted by PGE in 2007. Specifically, PGE contracted the Oregon Climate Change Research Institute (OCCRI) to evaluate how climate change could affect electric demand and hydroelectric generation in the future. Appendix E, Climate Change Projections in Portland General Electric Service Territory, provides the OCCRI report which provides the following information, among other data:

- Summarizes the current science of global climate change as it pertains to the energy sector in the Pacific Northwest (PNW).
- Describes the modeling basis from which future climate projections derive.
- Summarizes observed and projected changes in primary energy relevant climate variables on both a global and regional scale.
- Provides global climate change mitigation options.
- Provides 21st century climate change projections based on the latest available data for the Portland metropolitan area to aid PGE with its planning analysis.

Additionally, Chapter 3, Planning Environment, provides a more thorough discussion of this study and its application in the 2016 IRP.

1.2.3.2 Sustainability Efforts

PGE utilizes an integrated approach to sustainability that allows the Company to balance the environmental, social, and economic impact of all business decisions. Three key factors drive PGE's approach to sustainability: **People**, **Planet**, and **Performance**.

These factors guide the Company's long-term approach to business planning and decision-making. With People, Planet, and Performance as its driving principles, PGE employs a balanced approach in addressing the environmental issues affecting its customers, shareholders, and the community. As a result, responsible protection of the environment is compatible and aligned with cost-effective business practices. Moreover, sustainability is an embedded part of all of the Company's business decisions.

The subsequent sections discuss actions taken by PGE since the 2013 IRP, and future actions the Company plans to take in order to be more sustainable.

PGE's Activities in Support of a Sustainable, Diversified Future

PGE has taken numerous actions to ensure a more sustainable, diversified future for the Company's customers, shareholders, and the surrounding community, including actions stemming from the 2013

IRP. Through regular engagement with stakeholders, PGE is able to drive or support technological, regulatory, legislative, and business initiatives that help the State of Oregon and the Pacific Northwest in the continuous development of a sustainable infrastructure. An ongoing objective for PGE is to undertake cost-effective actions that are environmentally responsible, while retaining the right mix of resource diversity. The following demonstrate PGE's commitment to sustainability—particularly to People, Planet, and Performance:

PEOPLE

- Since 2009, the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) has ranked PGE number one in the nation for the number of renewable energy customers participating the Company's renewable power program.[12] In 2015, PGE's voluntary green power programs sold more renewable energy than any other voluntary energy company in the U.S.[13] As of December 2015, PGE had over 125,000 customers participating in its program, representing a 14.65% participation rate among eligible customers.
- In fall 2015, PGE launched the Green Future Solar program, which allows residential and business customers to purchase 1kW blocks of solar energy from a solar project in Willamina, Oregon. In April 2016, PGE successfully completed new enrollments with the program reaching its maximum capacity.
- PGE's Renewable Development Fund (RDF)[14] continues to support local renewable power projects, including the Portland Public Schools Solar Installation project in 2015. In collaboration with other parties, PGE installed more than 4,000 solar panels on six Portland Public Schools, making it possible for these schools to generate renewable energy and provide energy education opportunities for students.

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[12] U.S. Department of Energy, *Top Ten Utility Green Power Programs*, http://apps3.eere.energy.gov/greenpower/resources/tables/topten.shtml (retrieved on July 13, 2016).

[13] Id.

[14] PGE customers who purchase renewable energy support the development of new renewable power projects through the PGE Renewable Development Fund. In 2016, a new RFP process became available to distribute these funds for local renewable projects. Third-party vendors review applications for project funding and award funding based on return on investment, innovative technology, and public education potential. The Portfolio Options Committee, a group of stakeholders representing local advocacy groups, the OPUC, and the Oregon Department of Energy, oversee the process.

- PGE partnered with Nest and Energy Trust to pilot demand response technology, allowing customers to save energy and money and helping lower demand during peak hours.
- PGE invested in public safety awareness and outreach by participating in multiple school fairs and festivals, and launching Incident Management for Utilities Training Center to aid emergency preparedness.

PLANET

- PGE worked with stakeholders and legislators to propose legislation that ultimately led to the passing of the Oregon Clean Electricity and Coal Transition Plan (Senate Bill (SB) 1547), which includes requirements for PGE to: 1) generate 50% of its power from renewables by 2040, and 2) be coal-free by 2030 (with the exception of Colstrip which will be out of PGE's portfolio by 2035).
- PGE met Oregon's 2015 RPS requirement to supply 15 percent of the electricity PGE's customer's use from qualified renewable resources.
- PGE received the Envison® Sustainable Infrastructure Gold Award for the Tucannon River Wind Farm.
- With the cessation of coal-fired operations at PGE's Boardman facility at the end of 2020, the Company continues to assess the feasibility of biomass as a resource at the Boardman facility.
- To ease fish migration and improve river flow while generating electricity, PGE invested in projects on the Clackamas River system, including the North Fork Floating Surface Collector (FSC). The FSC is the main project in a collective group of projects aligned to achieve 97% safe passage of Endangered Species Act (ESA) listed juvenile salmonids. PGE built the FSC in compliance with its Clackamas River licensing requirements, which required the Company to build pumped FSC delivering a flow of 1,000 cubic feet per second. PGE invested just over $55 million in the project, and the FSC became operational on September 30, 2015. Since that time, the North Fork FSC has successfully attracted and escorted ESA-listed juvenile salmonids and other species of fish.

PERFORMANCE

- PGE fully owns and operates two wind farms—Biglow Canyon and Tucannon River—which have a total installed capacity of 717 MW.

- According to the American Wind Energy Association (AWEA), as of the end of 2015, PGE's 717 MW of owned wind ranks 3rd in the nation among utilities with owned or contracted wind capacity.[15]
- In 2015, PGE committed 5% of its annual fleet budget to the purchase of electric and plug-in vehicles. PGE also established Electric Avenue—a street of four DC Quick Chargers[16] and two Level 2[17] charging stations—outside the Company's headquarters in downtown Portland.

- In 2015, PGE effectively managed its power supply and business operations to partially offset the financial impact of weather, by maintaining a system reliability of 99.986 percent and average generating system availability of 92.5 percent.

Principles for Addressing CO_2 Emissions

Policy and political leaders at the regional, national, and international levels continue to grapple with how to implement carbon reduction regulation with minimal economic disruption. As the solutions for carbon reduction unfold, PGE is being prudent and taking reasonable steps to reduce greenhouse gas emissions and mitigate potential environmental impacts in Oregon.

The following principles guide PGE's efforts to sustainably reduce its CO_2 footprint:

- Continue to provide customers with reliable and affordable electric power while adhering to the OPUC IRP principle of balancing cost and risk in the selection of resource options.
- Continue to support acquisition of all cost-effective EE within the Company's service area through the Energy Trust.
- Continue to support federal action to achieve carbon emission reductions equitably across all sectors of the economy.
- Continue to support public policies that seek out lower-impact resources while striving to optimize generating portfolio diversity and maintaining reliability.

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[15] *The Top 10 U.S. Wind Energy Utilities Of 2015: AWEA*, http://nawindpower.com/the-top-10-wind-energy-utilities-of-2015-awea (retrieved July 13, 2016).

[16] DC Quick Chargers will charge an electric vehicle to 80 percent capacity in less than 30 minutes. DC quick-charge systems are typically installed in high-traffic public areas and strategic locations to allow drivers to charge on the go and extend their driving range.

[17] Level 2 chargers provide faster charging, using a 240-volt charger — the same voltage used for a clothes dryer. Level 2 charging systems are typically located in public and commercial locations.

- Continue to advocate for tax policy and incentives that help mitigate the cost to utility customers for energy efficiency and renewable power.

To deliver on these principles, PGE will continue to collaborate with regulators and stakeholders to ensure that Oregon's regulatory and statutory structures are sustainable and supportive of these principles.

CHAPTER 2. IRP Public Process

The Public Utility Commission of Oregon's (OPUC) Integrated Resource Planning guidelines and related orders frame PGE's IRP public process. Throughout the process, PGE's primary goal is to identify a resource action plan that provides the best combination of expected costs and associated risks and uncertainties for the Company and its customers. PGE does this by performing cost and risk analysis on a diversity of candidate portfolios over a planning horizon of 34 years. The portfolios consist of new and existing supply- and demand-side resources, which PGE evaluates under a variety of potential future environments.

For the 2016 IRP, PGE hosted several public meetings to discuss its modeling methodologies and the results of the numerous analyses conducted during development of this plan. At each public meeting, the Company shared the results of its research, analysis, and findings with external stakeholders at each public meeting. Specifically, PGE shared the anticipated resource requirements and alternatives for serving the Company's customers' future electricity needs, and sought feedback from stakeholders in return. Chapter 2 briefly discusses the IRP regulatory requirements and the public dialogue that helped shape the 2016 IRP.

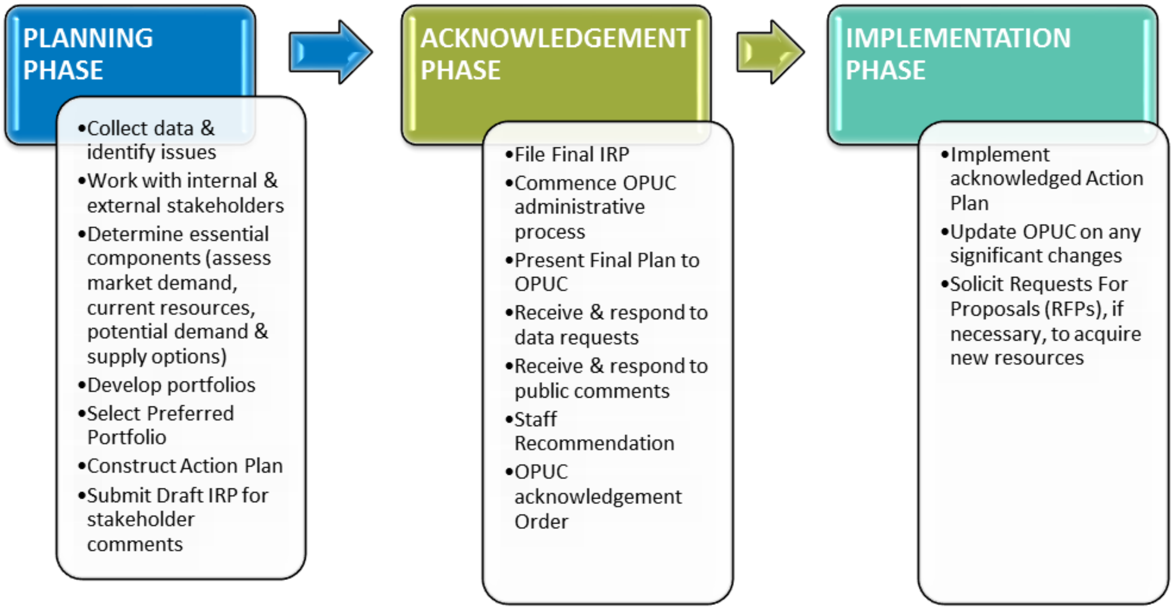
Chapter Highlights

- ★ **The primary goal of the IRP is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.**
- ★ **PGE actively seeks input from customers, OPUC staff and other stakeholders throughout the IRP process.**
- ★ **PGE hosted nine public meetings to discuss with stakeholders its future energy needs, modeling assumptions and methodology, and analytical results.**
- ★ **PGE also participates in a number of regional forums and work groups that inform and influence the Company's planning.**

2.1 Overview of Public Process

PGE's integrated resource planning public process is a collaboration of multiple parties, including customers, regulators, stakeholders, and independent consultants. Throughout the planning process, PGE shares the results of related research, analyses and findings with participating parties. PGE continuously engages with these various groups during the three-phase process shown below: 1) **Planning Phase**; 2) **Acknowledgement Phase**; and 3) **Implementation Phase**.

Using this process, PGE is able to produce and implement a resource plan—and an action plan—that balances expected costs, risks, and uncertainties to the benefit of the Company and its customers.



2.1.1 Planning Phase

The scope of the planning phase is to work with stakeholders and solicit input on assumptions, options, and techniques to best simulate resource procurement strategies or portfolios, for meeting future electricity demand. For the 2016 IRP, this phase began in 2014 and continued through 2016.

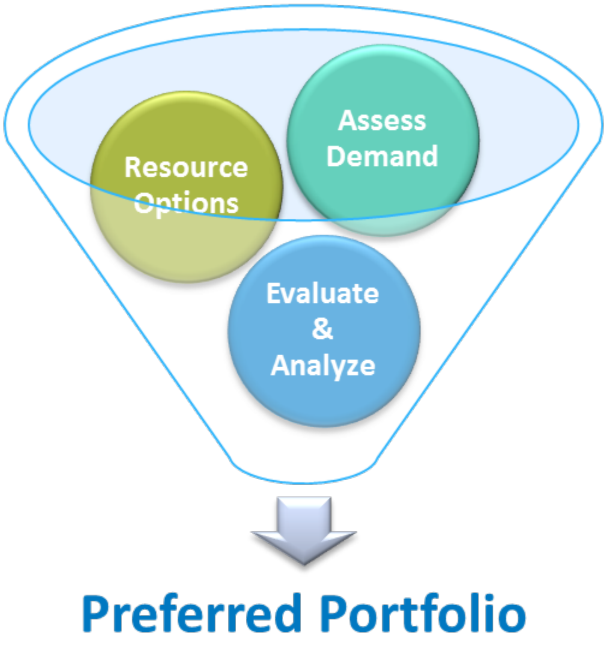
PGE began the process by reviewing the requirements of the Commission's 2013 IRP Acknowledgement Order (i.e., Order No. 14-415). The Company then assembled its internal, cross-functional planning team to collaborate regarding the appropriate studies and analyses needed to inform the 2016 IRP.

Subsequently, the Company reached out to OPUC staff and external residential, industrial, commercial, and renewable stakeholder groups to attend public meetings and provide input on the policies, methodology, and assumptions underlying the 2016 IRP.

PGE then gathered and reviewed the essential components of its analytical work, including modeling tools, research, and necessary data. The essential components of resource planning include:

- Evaluating environmental and other policy issues (Chapter 3, Planning Environment);
- Forecasting and assessing future customer demand (Chapter 4, Resource Need, and Chapter 5, Resource Adequacy);
- Reviewing existing resources (Appendix D, Existing Resources);
- Reviewing resource options that can meet future demand (including emerging technologies) (Chapter 6, Demand Options, Chapter 7, Supply Options, Chapter 8, Energy Storage, and Chapter 9, Transmission Options);
- Estimating long-term costs and risks of different resource procurement strategies (Chapter 10, Modeling Methodology);
- Identifying the Preferred Portfolio and Action Plan with the best cost/risk trade-off for customers (Chapter 11, Scoring Metrics, Chapter 12, Modeling Results, and Chapter 13, Action Plan).

Chapter 10, Modeling Methodology, provides a detailed explanation of all the analytical steps PGE employed in the development and analysis of portfolios. Chapter 11, Scoring Metrics, discusses the scoring metrics PGE applied to the various portfolios. Finally, Chapter 12, Modeling Results, identifies PGE's preferred portfolio.



After PGE selects a Preferred Portfolio and develops an Action Plan, the Company documents the entire resource planning process in a draft IRP, which PGE shares with external stakeholders for review.

2.1.2 Acknowledgment Phase

The acknowledgement phase begins when PGE files its final IRP with the OPUC. During this six-month process:

- PGE presents the results of its IRP to the Commission.
- Parties engage in a data discovery process.
- Commission staff and parties file their comments and recommendations with the OPUC.

This phase provides the Commission and stakeholders the opportunity to evaluate PGE's IRP and Action Plan to determine whether the assumptions, analysis, and action plan meet the OPUC's Integrated Resource Planning Guidelines. Upon the successful conclusion of this phase, PGE receives an acknowledgment order from the OPUC, which approves all or a portion of the Company's Action Plan. The acknowledgment order may set forth additional requirements or actions the Company should undertake, generally by the filing of the next IRP or IRP Update.

2.1.3 Implementation Phase

The implementation phase consists of the actual procurement of the demand-side, supply-side, and integration resources identified in the Action Plan. Oregon requires competitive procurement of all resources larger than 100 MW and with durations longer than five years. For this purpose, PGE typically issues Requests for Proposal (RFPs), which identify the characteristics of the need the Company intends to meet with new resources.

During the implementation phase, PGE initiates any studies or other actions set forth in the Commission's acknowledgement order. The Company provides a detailed update on these studies and actions to the OPUC in its IRP updates, which are due annually "on or before the acknowledgment order anniversary date."[18]

2.2 Regulatory Requirements

Regulatory orders and guidelines issued by the OPUC help inform PGE's planning process. The OPUC first established Oregon's IRP guidelines in 1989 via Order No. 89-507. In 2007, the OPUC modified the IRP guidelines in Order No. 07-002 (as corrected by Order No. 07-047).[19] The Commission updated the IRP guidelines again in Order No. 12-013, by adding requirements regarding flexible capacity resources. Throughout the 2016 IRP process, PGE collaborated with stakeholders and regulators to ensure its compliance with all guidelines.

PGE worked with stakeholders to ensure the Company fulfilled all the requirements set forth in Commission Order No. 14-415—PGE's acknowledged 2013 IRP order. As shown in Chapter 1, Planning History, PGE completed multiple studies during the planning phase to better inform its 2016 IRP decisions.

PGE's 2016 IRP complies with the guidelines set forth in the above-mentioned orders and all other applicable regulatory requirements. Appendix A, Compliance with the Commission's IRP Guidelines,

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[18] See OAR 860-027-0400(8).

[19] OAR 860-027-0400 also sets forth the OPUC IRP Guidelines.

provides a detailed description of the Company's compliance with all pertinent IRP guidelines. Likewise, Appendix B, PGE's Compliance with 2013 IRP Order (Order 14-415), shows that PGE fulfilled all the requirements of its 2013 IRP acknowledgment order.

2.3 2016 IRP Public Process

The public phase of the 2016 IRP started in the spring of 2015. Between April 2015 and November 2016, PGE:

- Conducted *nine* public meetings or roundtables
- Participated in *two* meetings with the OPUC Commissioners
- Provided responses to *over 100* parking lot or feedback questions from stakeholders.

In compliance with Order No. 14-415, PGE discussed portfolio development at four of the eight meetings.

Public meeting/Roundtable presentations are available online at www.portlandgeneral.com/irp.

Participants in PGE's public meetings included representatives from the following organizations:

- AB Saroka Energy
- Bonneville Environmental Foundation (BEF)
- Bonneville Power Administration (BPA)
- Cardno
- Citizens' Utility Board (CUB)
- Cleantech Law Partners
- Comverge, Inc.
- Small Business Utility Advocates
- City of Portland Bureau of Planning & Sustainability
- Energy Trust of Oregon (Energy Trust)
- EQL Energy
- General Electric Company (GE)
- Industrial Customers of Northwest Utilities (ICNU)
- NW Energy Coalition (NWEC)
- Northwest Power and Conservation Council (NWPCC)
- Oregon Department of Energy (ODOE)
- Oregon Department of Environmental Quality
- Oregon Public Utility Commission (OPUC)

- PacifiCorp dba Pacific Power
- Perennial Power Holdings, Inc.
- Renewable Northwest (RNW)
- Sierra Club
- Sumitomo Electric Industries, Inc.
- SunPower
- Williams Northwest Pipeline

The public meetings and technical workshops included discussion of the following resource planning building blocks, among other topics:

- Load-resource balance (future energy and capacity requirements)
- Capacity Contribution of renewables
- Flexible capacity needs
- Fuel market fundamentals and forecasts (natural gas and coal)
- Energy and capacity resource options, including demand-side and supply-side resources, and energy storage
- Federal and state policy developments, including the Clean Power Plan and Oregon Senate Bill 1547
- Transmission and natural gas transportation considerations
- Modeling approaches and IRP risk metrics.

See Appendix C, Public Process Agendas, for a detailed description of topics covered in PGE's public process.

Throughout the 2016 IRP public process, the Company received valuable stakeholder feedback. PGE used this feedback to develop multiple portfolios designed to meet the Company's incremental capacity and energy needs. PGE also created an online feedback form to provide public stakeholders a convenient method for submitting suggested portfolio options to PGE, or any other comments regarding PGE's 2016 IRP.

2.4 Regional Planning Participation

PGE tracks or participates in nearly 30 regional forums that help inform its planning process. The Company joins in these forums to remain aware of—as well as to guide and shape—regional initiatives focused on resource planning and utility operations. PGE is also able to identify and influence emerging issues and policy developments that could positively or negatively impact future portfolio choices.

CHAPTER 3. Planning Environment

With each IRP, PGE reviews the diversity of external factors that impact the Company's long-term resource planning. Factors such as changes in law and policy, general economic conditions, technological advances, and environmental concerns can influence PGE's overall resource strategy. For the 2016 IRP, PGE identified the following external influences as areas for consideration:

- Legislative and regulatory updates.
- Environmental issues (climate change, carbon reduction).
- Fuel considerations (natural gas prices).
- Energy market changes (subhourly scheduling, Energy Imbalance Market (EIM)).

In this chapter, PGE examines the potential implications of these external influences and provides a description of how the Company considers the effect of these outside factors in the 2016 IRP. PGE also presents information on the:

- Oregon Clean Electricity and Coal Transition Plan (OCEP).
- Impact of natural gas prices on the wholesale energy market.
- Results of the Company's 2015 Climate Change Study.
- Subhourly bilateral market, including PGE's efforts to self-integrate wind and participate in the Western Energy Imbalance Market.

Chapter Highlights

- ★ **Compliance with SB 1547 requires elevated long-term Renewable Portfolio Standard (RPS) procurement and removal of Colstrip 3 and 4 from PGE's portfolio.**
- ★ **The Clean Power Plan compliance introduces a price on carbon. The requirement to purchase and/or retire CO_2 allowances will lower WECC emissions to levels consistent with global climate agreements.**
- ★ **Load forecast and hydro futures account for the risk related to climate adjusted load growth and hydro availability.**
- ★ **Natural gas prices increase over time creating a justification for increased natural gas hedging activities.**

3.1 State and Federal Legislative Considerations

Significant state and federal legislative changes impact PGE’s 2016 integrated resource planning. The following section provides a brief summary of the key legislative changes considered by PGE.

3.1.1 Oregon Clean Electricity & Coal Transition Plan (SB 1547)

On March 8, 2016, Oregon Governor Kate Brown signed Senate Bill 1547 (SB 1547), known as the Oregon Clean Electricity and Coal Transition Plan (OCEP). The bill made far reaching changes to Oregon’s RPS, including increasing the requirement for eligible renewable energy to 50 percent by 2040 and eliminating all coal from Oregon’s allocated electricity supply by 2035.

3.1.1.1 Description

SB 1547 increases the requirement for eligible renewable generation for Oregon's largest utilities (excluding consumer-owned utilities) to 50 percent by 2040. As detailed in Table 3-1, RPS standards increase relative to legacy requirements beginning in 2025, when the standard is elevated from 25 percent to 27 percent. The amended RPS standards increase rapidly to 50 percent in 2040 and beyond.[20] Figure 3-1 depicts PGE’s increased RPS requirements.

TABLE 3-1: SB 1547 RPS requirements

	Legacy RPS Requirement (% of load)	SB 1547 Requirement (% of load)
2015	15%	15%
2020	20%	20%
2025	25%	27%
2030	25%	35%
2035	25%	45%
2040	25%	50%

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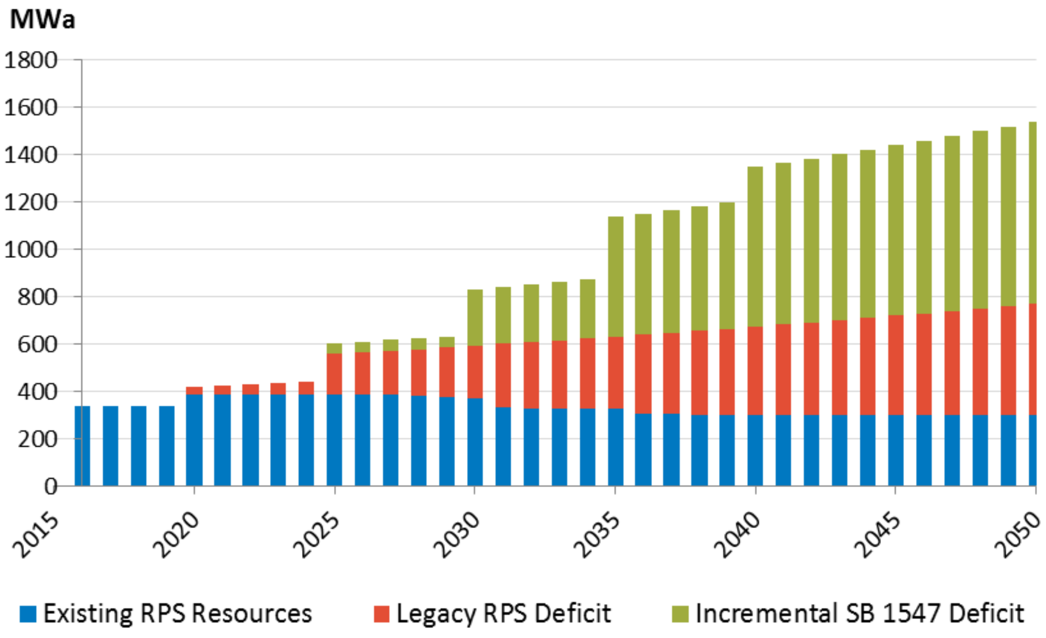
[20] ORS 469A.052.

FIGURE 3-1: PGE's RPS requirements



SB 1547 adjusts the Renewable Energy Certificate (REC) banking rules applicable for compliance with the RPS. Prior to the enactment of SB 1547, utilities could bank a REC indefinitely. Under SB 1547, RECs banked before passage of the act retain their infinite life (infinite life RECs). After the act, utilities must use the RECs generated by existing resources in the contemporaneous compliance year, or in the following five compliance years (five-year RECs).

RECs generated by new resources—brought online after the act, but before year-end 2022—create infinite life RECs for the first five years of generation, and five-year RECs thereafter. All generation brought online after year-end 2022 will create five-year RECs. In order to preserve infinite life RECs, SB 1547 eliminates the requirement for 'First-In, First-Out' retirement of RECs. Compliance entities are free to retire RECs in the order of preference.[21]

Another major element of SB 1547 is the elimination of coal-fired power from Oregon's allocated power supply. By January 1, 2030, Oregon electric utilities must remove from rates, all costs related to coal-fired generation. This provision has the effect of removing all coal-fired generation, both in and out of state, from Oregon ratepayer's power supply.

SB 1547 grants an exception for PGE's share of Colstrip Units 3 and 4, so long as PGE fully depreciates the facility by the end of 2030. As a result, PGE is able to recover the costs and benefits related to the continued operation of Colstrip Units 3 and 4 in the Company's rates until 2035.

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[21] ORS 469A.140.

SB 1547 contains a small-scale renewable[22] goal of 8 percent capacity by 2025. PGE is working with the Oregon Department of Energy (ODOE) and other parties to establish reporting guidelines for the goal.

3.1.1.2 Consideration in 2016 IRP

PGE incorporates the major elements of SB 1547 into the 2016 IRP, as follows:

- **The 2016 IRP fully depreciates Colstrip Units 3 and 4 by year-end 2030.** PGE removes the units from the Company's planned power supply by January 1, 2035.
- **The 2016 IRP elevates PGE's RPS requirements in 2025 and beyond.** PGE models the necessary RPS additions consistent with 50% of retail load in 2040 to reflect the significant RPS additions needed after the action plan period.
- **The 2016 IRP applies new REC banking logic.** PGE designs IRP portfolios to incorporate REC banking logic consistent with SB 1547 language regarding REC life.
- **The 2016 IRP simulated power prices include the effects of new renewables.** PGE's simulation of the wholesale market includes all additional renewables necessary to comply with SB 1547 through 2050. Chapter 10, Modeling Methodology, and Appendix H, AURORA Market Prices provide a discussion of the simulated prices.

Chapter 12, Modeling Results, discusses PGE's strategies for compliance with SB 1547.

3.1.2 Tax Credits

In December 2015, as part of the Consolidated Appropriations Act of 2016, Congress extended the availability of the Production Tax Credit (PTC) and Investment Tax Credit (ITC).

The PTC is a tax-credit awarded for each megawatt-hour (MWh) of generation from a qualifying energy resource for the first ten years of the resource's operation. Historically, the tax credit was available to wind, biomass, hydroelectric, and geothermal energy resources. Beginning in 2017, the tax credit is only available to wind energy resources. The tax credit is inflation-adjusted, and, in 2016, is worth $23 per MWh.

For the first time in the history of the PTC, Congress established a phase-down schedule for the PTC. Projects that commence construction in 2016 qualify for the full value of the tax credit. Projects that commence construction after 2016 receive a reduced tax credit. See Table 3-2 for the specific PTC value available to projects that commence construction, or qualify by other means, for a given year. PGE provides additional discussion regarding the Company's PTC strategy in Chapter 12, Modeling Results.

Facilities may also qualify for the PTC by taking advantage of the Internal Revenue Service's Five Percent Safe Harbor provision, rather than initiating construction. Project owners can take advantage of the safe harbor provision by incurring at least five percent of the total cost of the facility in the qualifying year. After qualifying for safe harbor, project owners have four years to bring the facility online.

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[22] ORS 469A.210.

TABLE 3-2: PTC phase-down schedule

Qualifying Year	% of Full PTC Value	PTC Value
2016	100%	$ 23.00
2017	80%	$ 19.20
2018	60%	$ 14.40
2019	40%	$ 10.00
2020+	0%	$ -

The Consolidated Appropriations Act of 2016 also extends the ITC. The ITC allows for receipt of a tax credit equal to a fixed percentage of eligible equipment costs. The full 30 percent ITC value is available to all solar projects that commence construction by 2019. Projects that commence construction after 2019 receive a reduced tax credit. See Table 3-3 for the specific ITC value available to projects that begin construction in a given year.

In contrast to the PTC, the ITC is continually available to project owners at the 10 percent level after 2021. The ITC is also accessible to geothermal projects at the 10 percent level in all years.

TABLE 3-3: ITC phase-down schedule

Qualifying Year	ITC Value
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%
2022+	10%

3.1.3 EPA Clean Power Plan

On August 3, 2015, the President of the United States announced the release of the prepublication version of the Clean Power Plan (CPP)[23]—promulgated to regulate CO_2 pollutants from qualifying, existing electric generating units (EGUs).[24] On the same date, the EPA also released final rules under

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[23] The CPP is the result of a final rulemaking issued by the EPA under section 111(d) of the Clean Air Act (CAA). *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64661, 64663 (Oct. 23, 2015) (amending 40 C.F.R. pt. 60).

[24] Id.

section 111(b) to regulate new EGUs according to a separate rulemaking.[25] Publication in the Federal Register occurred on October 23, 2015, making the rules final.

In a 5-4 ruling on February 9, 2016, the Supreme Court of the United States ordered the EPA to hold off on any efforts to implement the CPP, until the completion of legal proceedings challenging the rule. The ruling came after the U.S. Court of Appeals for the District of Columbia Circuit denied challenges to stay the regulations in January 2016. Assuming the parties appeal the District of Columbia Circuit's decision to the Supreme Court, analysts do not expect a decision on the CPP until early- to mid-2018. During the stay, states have slowed plan development considerably, with many states choosing to suspend implementation of the CPP.

3.1.3.1 Federal Emission Guidelines

Targets

The EPA issued the CPP under its authority granted by the Clean Air Act (CAA) section 111(d) which relates to existing resources.[26] For this reason, the CPP applies only to existing resources. These rates express the 'Best System of Emission Reductions' (BSER) for CO_2 from existing units.

Under the final CPP, the EPA established a CO_2 emission performance rate for the two subcategories of existing EGUs regulated by the CPP:

- Fossil fuel-fired electric steam generating units (EGUs).
- Stationary combined-cycle combustion turbines (CCCT).

TABLE 3-4: Clean Power Plan emission guidelines

Fossil Fuel-Fired Steam EGU Emission Guideline	Stationary Combined Cycle Combustion Turbine Emission Guideline
1,305 lbs CO_2/ MWh	771 lbs CO_2/MWh

The EPA calculated individual state goals according to the 2012 proportion of steam and CCCT generation. As an example, Montana has no CCCT EGUs and their final state goal is equal to the electric steam EGU emission rate of 1,305 lbs CO_2/MWh. Conversely, Oregon's generation profile includes both electric steam generation and CCCT generation, resulting in a middling goal of 871 lbs CO_2/MWh.

The EPA also translated each state's rate-based goal into a CO_2 mass goal. The EPA defines a rate-based goal as an annual limit on the average emission intensity of qualifying units, but does not limit total emissions.[27] Alternatively, EPA identifies unique mass-based goals for each state. The mass-based goal serves as a limit on the total tons of CO_2 that qualifying units may emit annually. While EPA designed the two standards to be of equivalent stringency, states will likely find compliance

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[25] Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64510 (Oct. 23, 2015), (amending 40 C.F.R. pts. 60, 70, 71, and 98).

[26] 80 Fed. Reg. 64661, 64812.

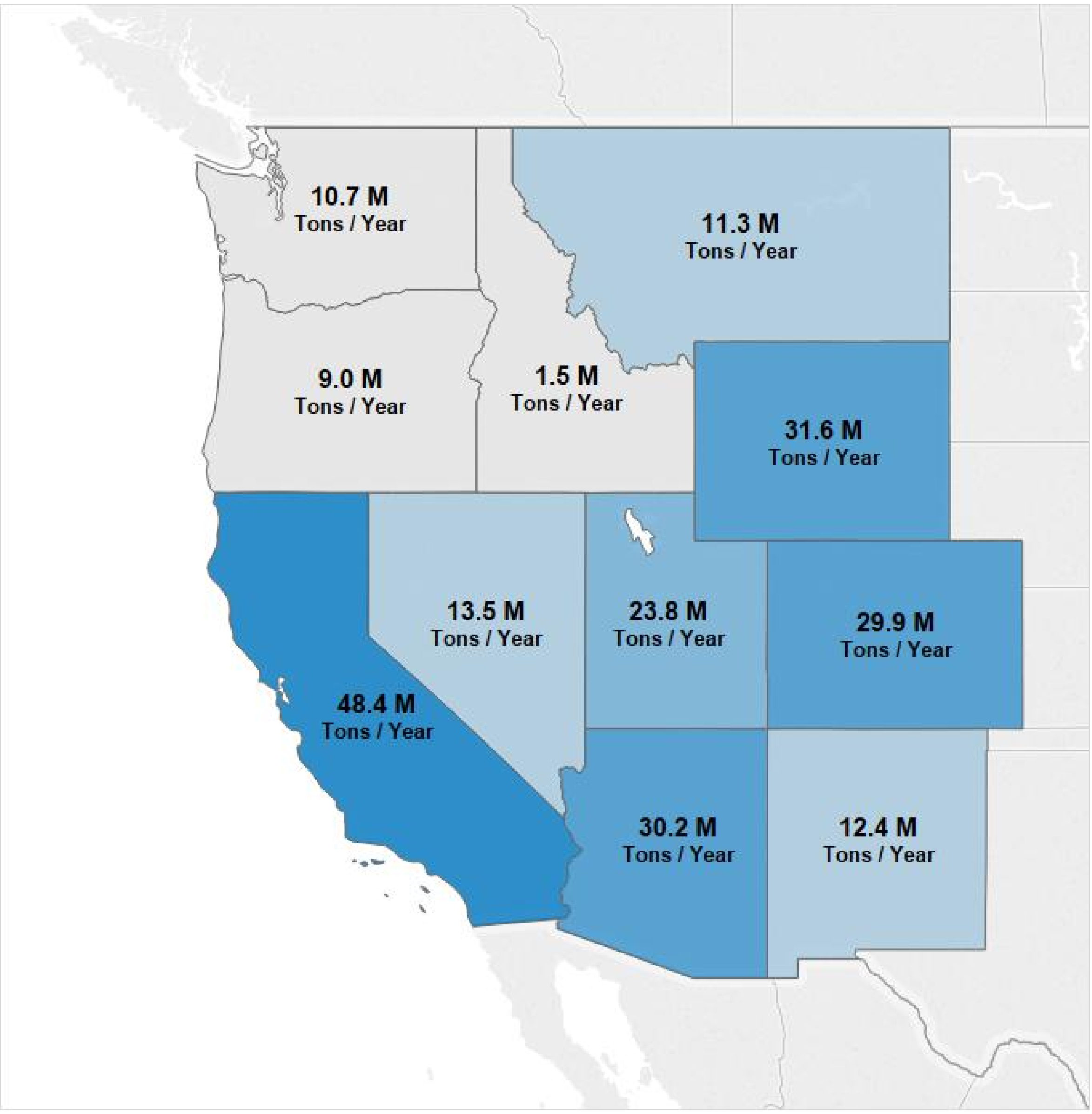
[27] 80 Fed. Reg. 64510, 64527.

with one or another standard preferable. For its CAA section 111(d) implementation plan, a state will determine whether:

- To apply either rate-based or mass-based emission guidelines to each affected EGU, individually or together; or,
- To meet either an equivalent statewide rate-based goal or an equivalent statewide mass-based goal.

The following figure illustrates the final mass-based goals for the western U.S.

FIGURE 3-2: Clean Power Plan final state mass-based goals



Compliance Periods and Goals

As currently written, compliance with the CPP begins on January 1, 2022 (subject to modification pending the outcome of litigation). State plans must require affected EGUs to achieve the chosen emission guideline over the interim period (2022-2030), each interim step, and each final reporting period.[28] "Interim period" means the period of eight calendar years from January 1, 2022, through December 31, 2029. The interim period is composed of at least three "interim steps":

Interim step 1 (January 1, 2022 through December 31, 2024).

Interim step 2 (January 1, 2025 through December 31, 2027).

Interim step 3 (January 1, 2028 through December 31, 2029).

EPA intended the interim steps to each have their own interim goal. A state may design its own emissions reduction trajectory, provided that the state meets the interim goal—on average—over the eight-year period.

State Implementation Plans

EPA envisions four "plan pathways" that could be adopted by states in their implementation plans—although states are free to customize their own pathway. Should a state choose not to submit a state implementation plan, the EPA will require that units comply with one of the proposed model rules.

1. States may establish federally enforceable, mass-based CO_2 emission standards for affected EGUs, complemented by state-enforceable mass-based CO_2 emission standards for new fossil fuel-fired EGUs. This could involve an emission budget trading program that includes affected EGUs as well as new fossil fuel-fired EGUs. Trading may occur without the need for a multi-state plan.[29]
2. States may establish federally enforceable, mass-based CO_2 emission standards for affected EGUs. This would facilitate interstate trading, either through a single-state plan or through a multi-state plan.[30]
3. States may establish federally enforceable, subcategory-specific rate-based CO_2 emission standards for affected EGUs, consistent with the CO_2 emission performance rates in the emission guidelines. This approach provides for interstate trading, through either a single-state or multi-state plan.[31]
4. States may establish federally enforceable rate-based CO_2 emission standards at a single level that applies for all affected EGUs, consistent with the state rate-based CO_2 goal for affected EGUs in the emission guidelines. This provides for interstate trading, through a state plan that meets a single weighted-average, multi-state rate-based CO_2 goal.[32]

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[28] "Final period" means the period that begins on January 1, 2030, and continues thereafter.

[29] Preamble at 882.

[30] Preamble at 882-83.

[31] Preamble at 883.

[32] Preamble at 883-84.

Plans that employ a mass-based emission trading program must also contain requirements that address increased emissions from new sources. This increase is beyond the emissions expected from new sources, if existing EGUs were given standards of performance in the form of the subcategory-specific emission performance rates. EPA refers to this potential for increased emissions from new sources as “leakage.”

CPP Compliance Instruments and Trading

The ability to trade compliance instruments, both intrastate and interstate, has the potential to lower the overall cost of compliance. The EPA encourages interstate trading of compliance instruments; however, a state’s implementation plan must satisfy several criteria. Intrastate trading of compliance instruments is generally permissible under the CPP. To facilitate trading, the EPA requires that state implementation plans incorporate a mechanism to track the creation, transfer, and use of compliance instruments.

Under a rate-based implementation plan, the EPA defines the relevant compliance instrument as an Emission Rate Credit (ERC). One ERC represents one MWh of carbon free generation.[33] An eligible unit must acquire and retire enough ERCs so that the average emission intensity of the unit and ERCs meets the rate-based target.[34]

Under a mass-based standard, the EPA defines the relevant compliance instrument as an allowance. Similar to allowances used in the California and Regional Greenhouse Gas Initiative (RGGI) carbon markets, the holder of a carbon allowance may retire the allowance to permit the emission of one ton of CO_2. Unlike ERCs, resources do not create or generate allowances. There is a fixed quantity of allowances, which states dispense according to a mechanism defined in their implementation plan. States are free to auction allowances or allocate them at no cost on whatever basis they choose.

Interstate trading can only occur between states with compatible state implementation plans. States with mass-based plans cannot trade with rate-based states and states cannot convert an allowance into an ERC (or vice-versa).

3.1.3.2 Incorporation into IRP

In the 2016 IRP, PGE models implementation of the CPP with a mass-based implementation plan—inclusive of the ‘new source complement’ (NSC)—for all western states. PGE assumes that all states (eastern and central states included) engage in both interstate and intrastate trading of mass-based compliance instruments.

NSC mass-based plans are presumptively approvable and the decision to model NSC mass-based plans provides PGE with some assurance that the stringency of the CPP is fully present. PGE believes that other state implementation plans are likely to be more cost-effective for PGE customers. For that reason, PGE supports a subcategory rate-based plan for Oregon, which can deliver zero incremental compliance costs for customers.

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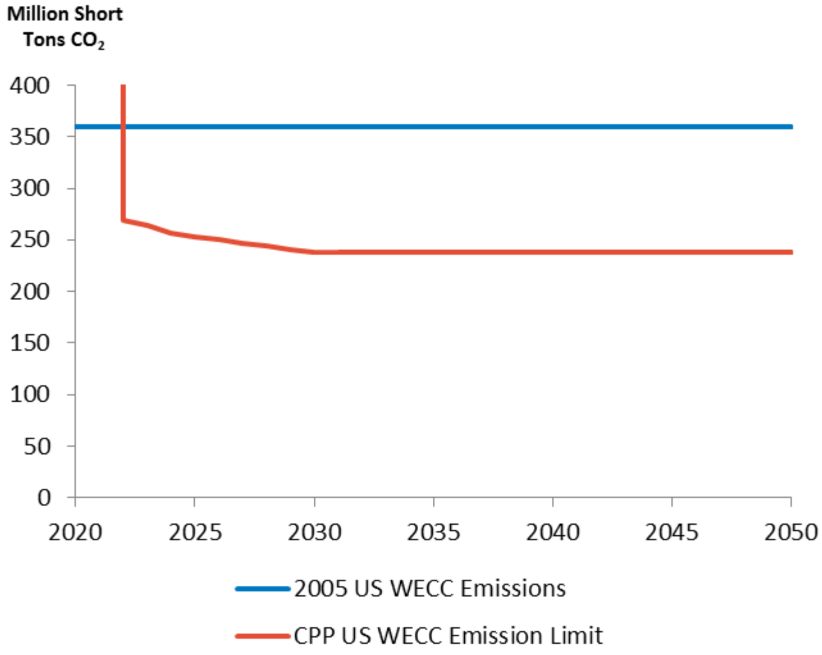
[33] 80 Fed. Reg. 64661, 64949; 40 C.F.R. §60.5790(c)(2)(ii).

[34] Id.

PGE models a mass-based NSC plan within the IRP, due to modeling feasibility and because it fully represents the possible stringency of the CPP. The decision to model a mass-based plan is not—and should not be construed as—an indicator of PGE's support for a mass-based plan for state of Oregon CPP compliance purposes.

Modeling an NSC mass-based plan is largely consistent with legacy planning techniques that apply CO_2 costs to all emitting resources, with the addition of a cap on total CO_2 emissions. In the modeling, PGE assumes that all eligible resources, existing and new, participate in CPP compliance. PGE models all plans as 'trading-ready' and assumes that all states participate in interstate trading of mass-based allowances. The Company does not constrain statewide emissions to the state limit. Rather, PGE constrains total WECC-wide emissions to not exceed the aggregate limit of all western states. While the EPA does not identify allowance limits past 2030, PGE assumes the 2030 limitation persists across the simulation period. Figure 3-3 shows the aggregate CPP emission limit applied to units in the US WECC relative to 2005 emissions.

FIGURE 3-3: CPP emission limits across US WECC



Mass-based allowances have value because they permit emission of one ton of CO_2. Alternatively, an allowance can be sold to a counterparty for fair market value. When simulating the market behavior of a CPP eligible facility, the model must adjust the dispatch cost to account for the need to buy an allowance, or (if the facility was allocated allowances at no cost) the opportunity cost related to forgoing revenue associated with the sale of the allowance.

In the 2016 IRP, PGE assumes that all emitting resources either purchase or forfeit mass-based allowances in order to dispatch. The price of a mass-based allowance in the 2016 IRP is associated with the forecasted trading price of a mass-based allowance in a national CPP compliance marketplace. PGE relies upon third-party forecasts of allowance prices traded in a national marketplace. Specifically, PGE's IRP relies upon the CO_2 price forecast provided by Synapse Energy Economics in its "Spring 2016 National Carbon Dioxide Price Forecast."[35]

Synapse's CO_2 price forecasts reflect a range of fundamentally based effective CO_2 prices that, when applied nationally, would allow for CPP compliance from 2022-2030 and science-based climate goals to be achieved by 2050. Synapse's modeling of the CPP also assumes that states trade mass-based allowances, and that regions of supply can be used to satisfy regions of demand across states and interconnections. As such, Synapse's CO_2 price forecasts are an effective third-party forecast of the clearing price for CPP mass-based allowances or alternative national CO_2 cap and trade policy that complements or replaces the CPP beyond 2030.

The Synapse CO_2 price forecast includes three future cases, of which PGE has modeled the 'high' and 'mid' case. The range of the prices reflects the uncertainty with respect to future policy decisions regarding availability of technology carbon offsets and the stringency of subsequent national carbon policies. Figure 3-4 illustrates the range of Synapse's CO_2 price forecast including:

- **A mid case with a real-levelized CO_2 price of $39 per short ton (2016 dollars).** The mid case begins in 2022 at $20 per ton increasing to $26 per ton in 2030 (2016 dollars). Synapse assumes the implementation of further reasonable federal policies, in addition to the CPP, to achieve—by 2050—science-based climate targets lowering electric sector emissions by 80 percent relative to 2005 emissions. By 2050, CO_2 prices increase to $82 per ton in 2016 dollars ($158 per ton nominal).
- **A high case with a real-levelized CO_2 price of $60 per short ton (2016 dollars).** The high case begins in 2022 at $25 per ton increasing to $43 per ton in 2030 (2016 dollars). The high case includes regulatory requirements more stringent than the CPP beginning in 2027. Beyond 2030, regulations require the electric power sector to lower emission 90 percent below 2005 levels in order to offset continued emissions in other sectors of the economy.[36] By 2050, CO_2 prices increase to $111 per ton in 2016 dollars ($215 per ton nominal).

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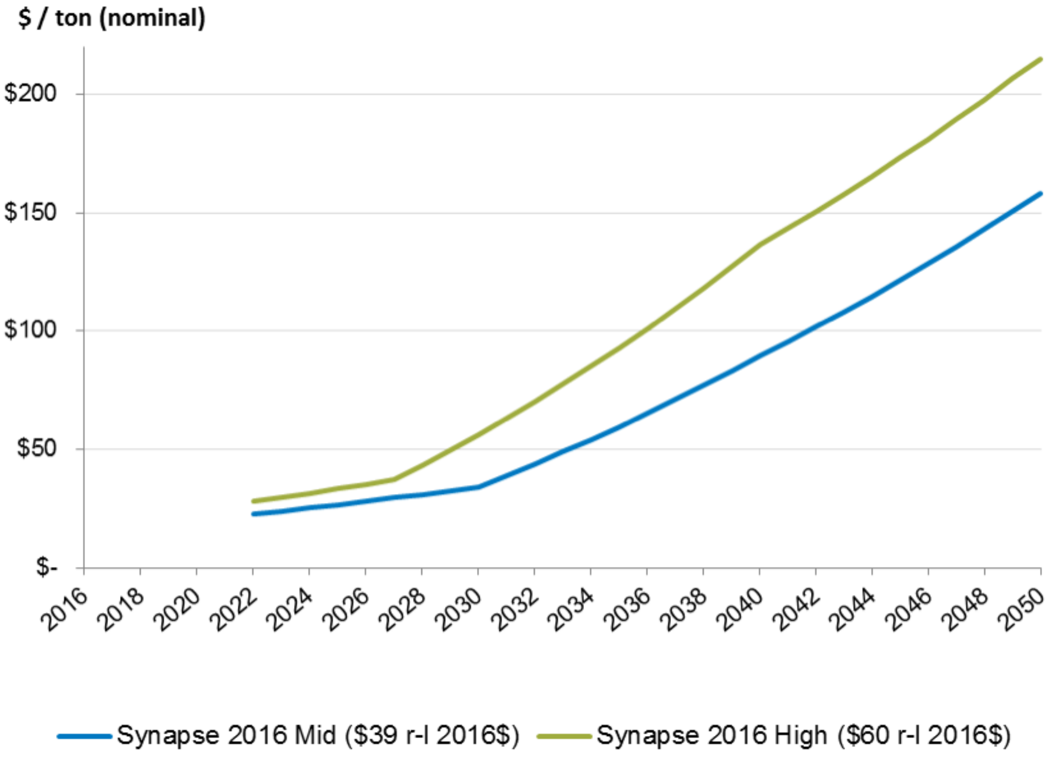
[35] Luckow, Patrick, et al. "Spring 2016 National Carbon Dioxide Price Forecast." Synapse Energy Economics, updated March 16, 2016, accessed on October 23, 2016.

[36] "Spring 2016 National Carbon Dioxide Price Forecast." Dated March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008_0.pdf.

FIGURE 3-4: Synapse CO_2 price forecasts



PGE's 2016 IRP portfolio simulation includes Synapse's mid case CO_2 price forecast as the Reference Case clearing price for mass-based allowances. The IRP models additional futures including zero effective CO_2 price (CPP constraints remain in-place) and Synapse's high CO_2 price case. See Chapter 12, Modeling Results, for additional descriptions of CO_2 prices modeled in the IRP.

The 2016 IRP does not model the potential effects of EPA's Clean Energy Incentive Program. Given the effect of current litigation on the timing of CPP implementation, it is unlikely that many western states will elect to participate in the Clean Energy Incentive Program[37] and submit final implementation plans before the close of the program's 2020-2022 operative period.

3.1.4 Other Greenhouse Gas Regulation

3.1.4.1 Paris Agreement

On December 12, 2015, representatives of 195 countries at the 21st Conference of the Parties (COP21), negotiated and adopted the Paris Agreement (Agreement).[38] As of August 2016, 180 United

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[37] "The EPA is providing a Clean Energy Incentive Program (CEIP) to reward early investments in renewable energy (RE) generation and demand-side energy efficiency (EE) measures that generate carbon-free MWh or reduce end-use energy demand during 2020 and/or 2021. State participation in the program is optional." *See* https://www.epa.gov/cleanpowerplan/fact-sheet-clean-energy-incentive-program, accessed on October 23, 2016.

[38] COP21 operates within the framework of the United Nations Framework Convention on Climate Change (UNFCCC), which deals with greenhouse gas emissions mitigation, adaptation, and finance.

Nations Framework Convention on Climate Change (UNFCCC) members had signed the treaty; 22 of which ratified it. The Agreement will enter into force (i.e., become fully effective) when 55 countries producing at least 55 percent of the world's greenhouse gas emissions ratify, accept, approve or accede to the agreement. The agreement is due to enter into force in 2020.

The agreement sets out a global action plan to put the world on track to limit global warming well below 2°C. Article 2, Section 1(a) – (c) of the Agreement sets forth the objectives of the convention, namely "enhancing the implementation" of the UNFCCC through:

a. *"Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change;*

b. *Increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production;*

c. *Making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development."*[39]

Countries aim to reach "global peaking of greenhouse gas emissions as soon as possible," recognizing that this will take longer for developing countries.

Before and during the Paris conference, countries submitted comprehensive national climate action plans called **intended nationally determined contributions** (INDCs). INDCs help each party "facilitate clarity, transparency and understanding" as to how it will contribute towards achieving the objectives of the Convention. INDCs should include, as appropriate, quantifiable information on the:

- Reference point.
- Time frames and/or periods for implementation.
- Scope and coverage.
- Planning processes.
- Assumptions, and methodological approaches to achieve the Conventions goals.

As an example, the INDC for the United States (US) indicates that the US intends to achieve an economy-wide target of reducing its greenhouse gas emissions by 26-28 percent below its 2005 level in 2025 and to make best efforts to reduce its emissions by 28 percent. The US' INDC states that this target is consistent with a straight line emission reduction pathway from 2020 to deep, economy-wide emission reductions of 80 percent or more by 2050. However, the US does not intend to utilize international market mechanisms to implement its 2025 target.

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[39] *See* United Nations / Framework Convention on Climate Change (2015), Paris Agreement, 21st Conference of the Parties, Paris: United Nations.

Also as part of the agreement, Parties agreed to come together and engage in *global stocktake* every five years to assess the progress towards achieving the purpose of the Agreement, with the first meeting planned in 2023.[40] Each Party must also report to each other—and the public—on how well they are doing to implement their targets and track progress towards the long-term goal through a robust transparency and accountability system.

Parties also agreed to strengthen society's ability to deal with the impacts of climate change and provide continued and enhanced international support for adaption to developing countries. The agreement also recognizes the importance of averting, minimizing, and addressing the loss and damage associated with the adverse effects of climate change and acknowledges the need to cooperate and enhance the understanding, action, and support in different areas such as early warning systems, emergency preparedness, and risk insurance.

3.1.4.2 North American Climate, Clean Energy, and Environment Partnership

On June 29, 2016, at the North American Leaders Summit in Ottawa, Canada, the leaders of the United States, Canada, and Mexico announced the North American Climate, Energy, and Environment Partnership (the Partnership).[41] The Partnership contains an Action Plan that identifies activities the three countries will pursue, including:

- Advancing clean and secure energy
- Driving down short-lived climate pollutants
- Promoting clean and efficient transportation
- Protecting nature
- Advancing science
- Showing global leadership in addressing climate change.

The Action Plan identifies the following activities specific to the electric power industry:

- Strive to achieve a goal for North America of 50 percent clean power generation by 2025, including renewable, nuclear, and carbon capture and storage technologies, as well as demand reduction through energy efficiency (EE).
- Advance clean energy development and deployment (including renewable, nuclear, and carbon capture and storage technologies).
- Support the development of cross-border transmission projects, including for renewable electricity.

3.1.4.3 Incorporation into IRP

The Paris Agreement and the North American Climate, Clean Energy, and Environment Partnership are both major international policies designed to diminish global CO_2 emissions. PGE's IRP does not

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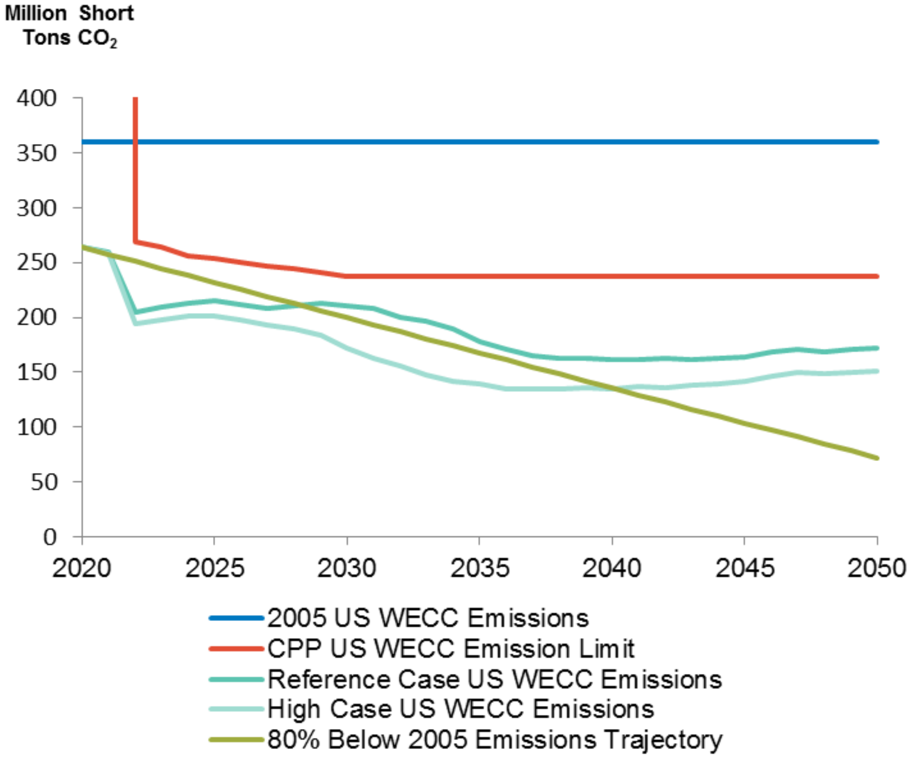
[40] Id. Paris Agreement, Article 14, Section 2.

[41] President of the United States, Barack Obama, Canadian Prime Minister, Justin Trudeau, and Mexican President, Enrique Peña Nieto.

attempt to model global emissions. PGE recognizes these agreements may lead to additional federal policy designed to limit CO_2 emissions from the electric power sector.

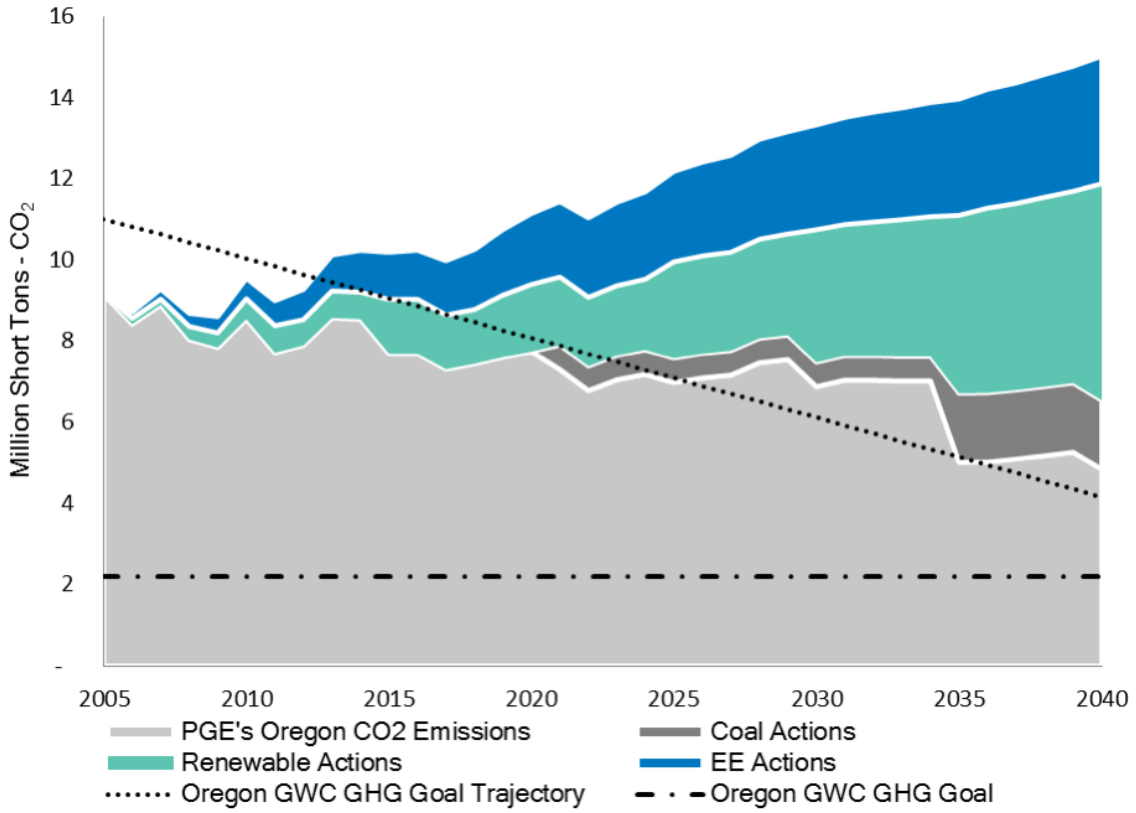
The 2016 IRP reviewed forecasted CO_2 emissions in the Western Interconnect. Under the Reference Case and High CO_2 Case, WECC CO_2 emissions trace the trajectory necessary to achieve an 80 percent below 2005 climate goal through 2040. Figure 3-5 illustrates US WECC emissions relative to CPP targets and more stringent climate goals. Notably, WECC-wide emissions are significantly below the CPP limit indicating that this emission constraint is non-binding for the illustrated futures. As described above and illustrated below, PGE's planning environment includes the potential for ambitious national CO_2, policies and PGE's assumed futures are consistent with this policy landscape.

FIGURE 3-5: Reference Case US WECC CO_2 emissions



When considering PGE's existing resources, forecasted EE adoption, and the need for additional RPS resources, PGE's projected 2025 CO_2 emissions of 7.0 million tons are 24 percent lower than its 2005 CO_2 emissions of 9.2 million tons. The Company's 2025 CO_2 emissions are also 43 percent lower than the 12.2 million ton level which would otherwise occur absent continued EE, new renewable resources, and the planned cessation of coal operations at Boardman. Chapter 12, Modeling Results, discusses the projected emissions associated with portfolios studied in the 2016 IRP.

FIGURE 3-6: PGE carbon dioxide emission profile over time



Whereas Figure 3-6 considers absolute CO_2 emissions, Figure 3-7 considers these emissions relative to customer demand. Specifically, Figure 3-7 measures carbon intensity as CO_2 output divided by load. As shown in Figure 3-7, PGE expects carbon intensity to fall by 61 percent over the 2005 to 2040 period, reflecting both the reduction in total emissions shown in Figure 3-7 and an increase in load over time. In year 2005, PGE emitted 0.49 tons of CO_2 for every MWh served, while in 2040 the Company projects a much lower emissions intensity of 0.19 tons per MWh.

FIGURE 3-7: PGE carbon dioxide intensity over time

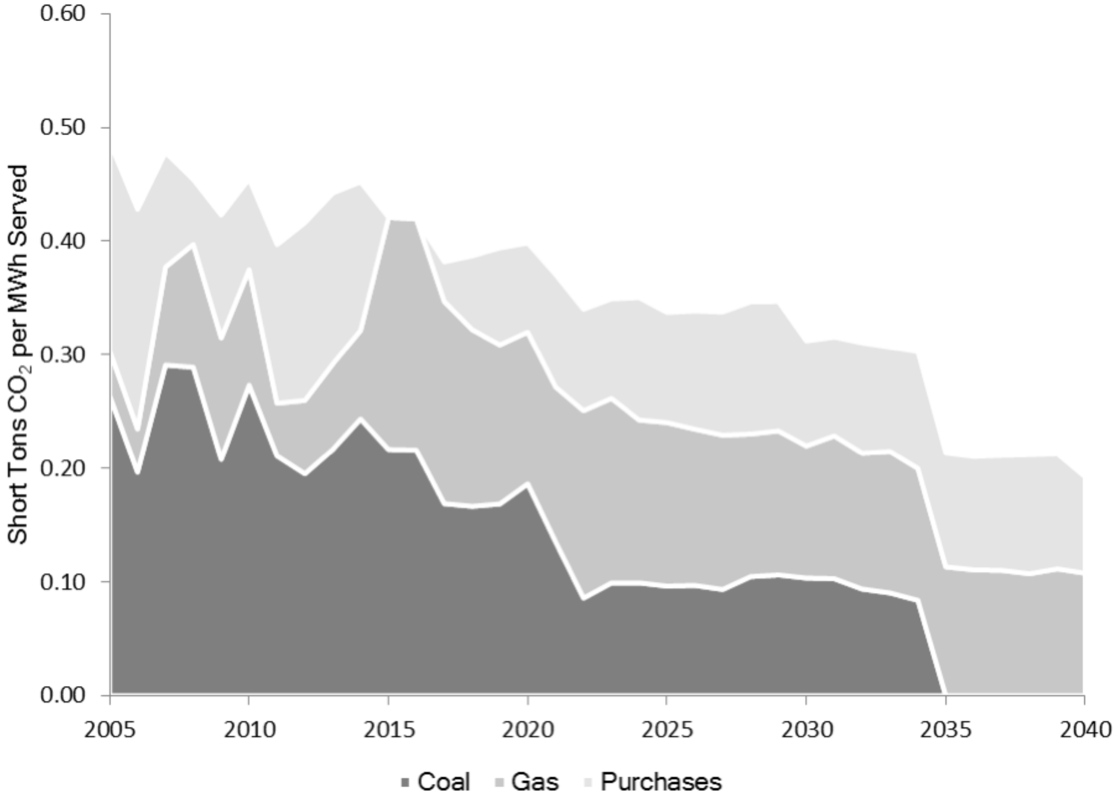


Figure 3-6 and Figure 3-7 show that, over time, EE, renewables, and cessation of coal operations at Boardman combine to substantially reduce PGE's carbon footprint.

3.1.5 Sulfur Dioxide, Nitrogen Oxide, and Particulates

New Resources

For new resources considered in the 2016 IRP, the Company assumes all new fossil fuel plants meet 'Best Available Control Technology' (BACT) standards. All generic plants enter service compliant with the current emissions requirements and overall capital costs for new resources contain the embedded compliance costs. Natural-gas-fueled plants have only small amounts of NO_X and SO_X emissions and are not subject to mercury emission rules. All PGE portfolios for new resources reflect the most likely regulatory compliance futures for state and federal emissions requirements for CO_2, SO_X, NO_X, and mercury.

Existing Resources

All existing PGE thermal plants are currently in compliance with emissions standards for sulfur oxides (SO_X), nitrogen oxides (NO_X), and airborne particulates. Table 3-5 below shows upcoming major investments for existing PGE resources to help remain in compliance with current state and federal requirements.

For existing thermal plants, PGE projects the following investments, as summarized in Table 3-5, for ongoing compliance with projected environmental standards.

TABLE 3-5: Major planned environmental investments, $ millions

Facility	PGE Share	Projected PGE Cost ($ Million) 2017–2020	2021–2025	2026–2033	Notes
Boardman	90%	$0.4	$0.0	$0.0	CCR landfill monitoring O&M, well and stormwater structure; coal combustion to cease 2020
Colstrip 3 and 4	20%	$1.8	$0.0	$0 to 40	Pond lining by 2020, potential SCR by 2027
Beaver	100%	$3.4	$0.0	$0.0	Replace cooling tower fill, gas line corrosion protection, GT8 CEMS, recovered oil tank
Port Westward	100%	$1.4	$0.0	$0.0	Replace CO, SCR catalysts
Carty	100%	$0.0	$0.0	$0.0	New facility 2016
Coyote Springs	100%	$2.5	$0.0	$0.0	New aux boiler, replace SCR catalyst
Total		$9.5	$0.0	$0 to 40	

Natural Gas-fired Power Plants

As stated above, the Company's natural-gas-fired plants have only small amounts of NO_X and SO_X emissions that are within air emissions requirements and not regulated by MATS rules.

Colstrip Unit 3 and Unit 4

PGE has a 20 percent ownership interest in Colstrip Units 3 and 4. The construction of these plants occurred approximately ten years after Colstrip Units 1 and 2 and five years after Boardman came into service. Units 3 and 4 use low-sulfur coal and scrubbers to reduce sulfur dioxide emissions. In recent years, PGE and the plant co-owners installed low-NO_X burners and mercury controls such that the units will remain in air emissions compliance until approximately mid-next decade. As mentioned above, SB 1547 governs the rate treatment of PGE's interest in Colstrip Units 3 and 4, requiring depreciation by 2030 and removal from rates by 2035.

The "reasonable progress" improvement requirement under U.S. EPA Regional Haze Program could trigger the need for additional NO_X controls, such as a selective catalytic reduction (SCR) retrofit by 2027.[42] However, to help with the State Regional Haze goals SmartBurn Technology will be installed by 2017.

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[42] No additional equipment or costs are required immediately for the mercury and air toxics rule or the EPA Regional Haze Federal Implementation Plan (FIP). However, the Reasonable Progress requirement of the Regional Haze Rule will likely require addition of selective catalytic reduction (SCR) systems for each unit by 2027.

A proposed revision to the coal combustion residual (CCR) rule will have a small cost impact to Colstrip 3 and 4. The CCR rule has various compliance dates. The pond lining identified in the above table reflects that requirement going out to 2020.

Boardman

In 2011, PGE installed low NO_x burners and mercury retrofits, which produced the expected emissions reductions. In 2014, PGE installed a dry sorbent injection (DSI) system to further reduce emissions of SO_2. The Boardman plant is fully compliant with NO_x, SO_2, and mercury requirements. PGE plans to cease coal-fired operations at Boardman by year-end 2020.

Compliance with Guideline 8 (Order 08-339)

Guideline 8 requires that PGE's portfolio planning reflect the most likely regulatory compliance future for CO_2, NO_x, SO_x, and mercury emissions. The Guideline directs that "the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection." Previously in this Chapter, and in Chapter 12, Modeling Results, PGE discusses how its planning reflects a likely range of CO_2 compliance cost scenarios. As discussed above, PGE's emissions levels of NO_x, SO_x, and particulates do not have a material impact on the Company's resource decisions, because new resources enter service compliant with emissions requirements, while existing thermal resources are compliant with reasonably predictable compliance futures. This extends to mercury and air toxics as well. As such, PGE did not conduct sensitivity analyses on these emissions.

3.2 Fuel Considerations

PGE relies on third-party consultant Wood Mackenzie for long-term fundamental fuel price forecasts (e.g., natural gas and coal), which serve as inputs to the IRP analyses.

3.2.1 Natural Gas Price Forecast

Natural gas prices are major drivers of wholesale electricity prices and the economic performance of power plants in the WECC. All of PGE's candidate resource portfolios include gas-fired resources to meet the Company's capacity needs. Thus, natural gas prices are a primary focus when assessing the performance of resource portfolios.

PGE derived the Reference Case natural gas forecast from market forward prices for the period 2017 through 2020 and the Wood Mackenzie long-term fundamental forecast for the period 2022 through 2035. A transition from the market price curve to Wood Mackenzie's long-term forecast is made by linearly interpolating for one year (2021). To develop western market prices, the long-term Henry Hub price forecast is input and the basis differentials for Sumas, AECO, and other WECC gas supply trading hubs are applied. Wood Mackenzie's forecast horizon is to 2035; after 2035, the trend from the end of this forecast period is extended for the duration of the IRP analysis time horizon through 2050.

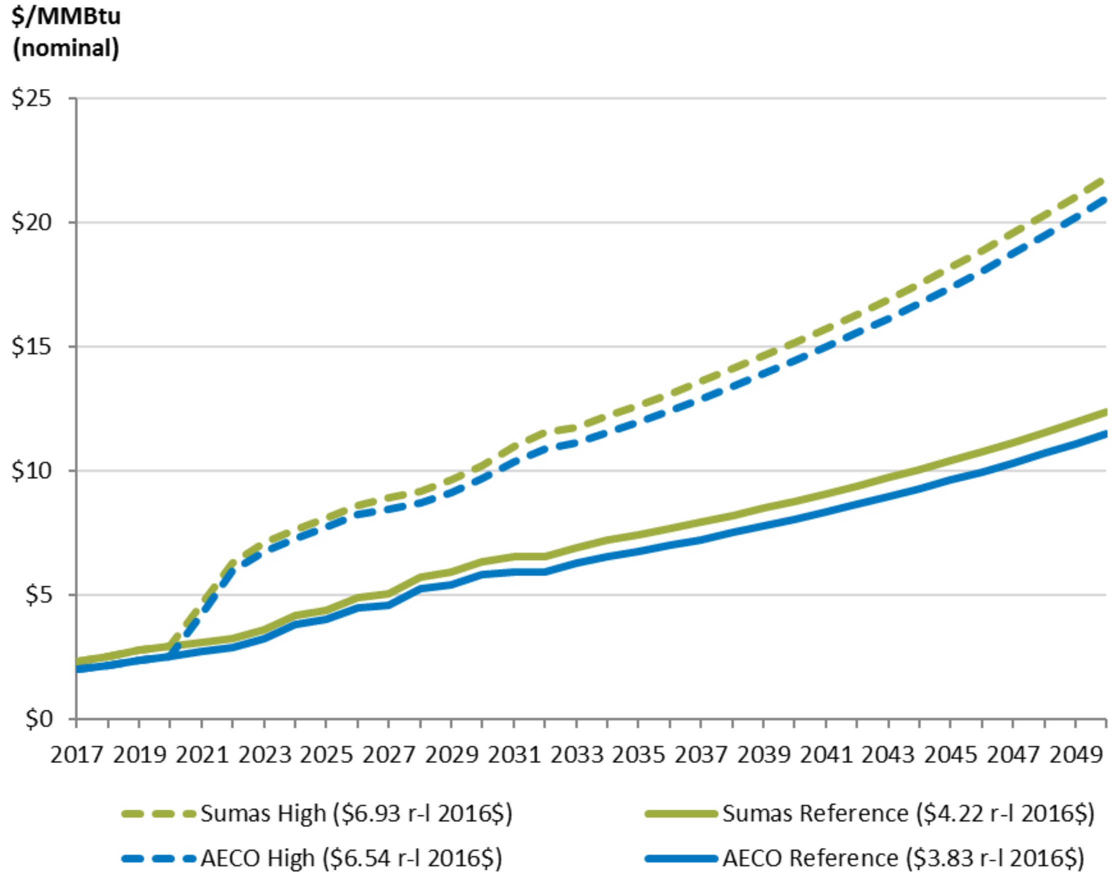
Wood Mackenzie provides semi-annual updates of its long-term fundamentals forecast. The fourth quarter of 2015 forecast update was the most recent update available for use in the IRP analysis. The following elements summarize this forecast:

- **Supply.** Expected reductions in production costs reduce breakeven costs and in-turn increase the potential long-term supply. Given low production costs, incremental pipeline capacity shapes the cost of bringing gas to market.
- **Demand.** Generally, demand will come from both domestic and export markets. Industrial consumption will help to drive domestic demand. Liquefied Natural Gas (LNG) export projects will tap overseas markets and pipeline exports to Mexico.
- **Price.** Pipeline capacity, relative reductions in associated gas production, and less efficient incremental sources of supply will drive prices upwards in the long-run.

In addition to this Reference Case forecast, the IRP analysis includes a high natural gas price case that represents a substantial increase in long-term prices relative to the Reference Case assumptions. PGE developed the High Case for this IRP by combining the Wood Mackenzie Reference Case forecast and the "High Oil" Price scenario from the Energy Information Administration's (EIA) Annual Energy Outlook 2015 (AEO 2015). The Company selected this scenario from the AEO 2015 because it results in the highest Henry Hub price (in real dollar terms). PGE combined the forecast Henry Hub prices from this AEO 2015 scenario with the western hub basis differentials forecast by Wood Mackenzie in the Reference Case to create a long-term price assumption for each of the points included for regional modeling. The High and Reference Case forecasts are identical through 2020. By 2050, however, the High Case results in a price for the AECO hub that is approximately 180 percent of the Reference Case (nearly $21 per MMBtu vs. $11.50 per MMBtu in nominal dollars for the High Case and Reference Case, respectively).

Figure 3-8 shows the Reference Case and High Case forecasts for AECO hub prices over the IRP analysis period.

FIGURE 3-8: Reference Case and High Case forecasts for Sumas and AECO hub prices



3.2.2 Coal Price Forecast

Coal prices remain important determinants of the regional supply stack. The market share of coal-fired resources declines across the analysis time horizon, likely as a result of a number of factors including the proliferation of renewables, natural gas prices, and the assumed cost of CO_2 emissions. PGE's analyses incorporate Wood Mackenzie's fundamental coal price forecasts for western markets from the same long-term release in Q4 2015 as the Reference Case natural gas price forecast.

The following factors summarize this coal price forecast:

- **Supply.** Continued reductions in mining costs are unlikely.
- **Demand.** Low natural gas prices displace coal generation and reduce coal demand. Export potential arising from demand in the Chinese market is not expected to be strong.
- **Price.** Competition with natural gas and limited potential for demand growth either domestically or internationally result in prices that are essentially flat in constant dollar terms over the longer-term.

3.2.3 Natural Gas Acquisition, Transportation, and Storage Strategy

3.2.3.1 Overview

With the addition of the Port Westward 2 (PW 2) and Carty power plants, PGE's natural gas-fired generation portfolio totals roughly 1,900 MW of nameplate capacity. This capacity represents a mixture of flexible gas resources. With gas-fired power plants representing a significant proportion of the Company's resource portfolio, managing the effects of natural gas prices and supply are key elements of PGE's overall strategy to supply reliable power at reasonable prices.

Figure 3-9 shows the locations of the Company's current gas-fired resources; Port Westward (PW 1), PW 2, Beaver, Coyote Springs, and Carty. The figure also shows the locations of transport pipelines and storage facilities. PGE holistically manages transportation, storage, and plant dispatch as components of a portfolio.

FIGURE 3-9: Gas-fired plants, pipelines, and storage

3.2.3.2 Existing Natural Gas Transportation and Storage

PGE currently acquires and delivers natural gas to the PW 1, PW 2, Beaver,[43] Coyote Springs, and Carty plants. PGE collectively refers to PW 1, PW 2, and Beaver as the PW-Beaver Complex.

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[43] Beaver 8 is not included due to its relative size (24 MW of nameplate capacity). The gas transportation and storage strategy discussed for the PW-Beaver Complex can also serve the needs of Beaver 8 when necessary.

No-Notice Service is a pipeline delivery service which allows customers to receive gas on demand without making prior nominations to meet peak service needs and without paying daily balancing and scheduling penalties.

NW Pipeline provides gas transportation services for the PW-Beaver Complex from Sumas, Washington, and various points in the Rocky Mountain Region. The K-B Pipeline provides the final link from the main NW Pipeline interconnect to these plants.

PGE contracts for use of Northwest Natural Gas Company's (NW Natural) Mist Storage Facility, which connects to the PW-Beaver Complex. The current Mist storage contract expires in 2017. To replace the Mist agreement and provide for resource fueling needs, PGE entered into a Precedent Agreement with NW Natural for firm storage at NW Natural's North Mist Expansion project, located north of the Mist Storage Facility. The North Mist Expansion agreement will provide PGE approximately twice the storage volume the Company currently has at Mist as well as No-Notice Service.

TABLE 3-6: North Mist Expansion storage rights

Contract Provision	Size/Scope
Withdrawal Rights	120,000 Dth/day
Injection Rights	56,000 Dth/day
Flexibility	No-Notice Service

Gas Transmission Northwest (GTN) provides gas transportation services from Alberta, Canada, (AECO) to supply Coyote Springs and Carty.

3.2.3.3 Supply

PGE's general gas procurement strategy is to use financial instruments to hedge price risk and then purchase physical gas at index. This is a least cost approach to achieving two important goals with respect to fueling the Company's natural gas-fired plants:

1. Reliable physical supply;
2. Price risk mitigation.

PGE uses market instruments such as financial swaps to hedge gas price exposure. This allows the Company to fix the price of gas without buying the physical commodity until it is required. Over time, the overall gas market has transitioned from long-term physical purchases to a combination of shorter-term physical purchases (at index)[44] and financial instruments to lock in prices over longer periods of time. Specifically, PGE's Mid-Term Strategy employs a layering approach to gas price hedging. Under this approach, the price customers pay—for gas expected to be used in a particular year—is determined by the aggregate financial transactions made for that year during the preceding

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[44] Under an index contract, the price paid is the market price for gas at the time of delivery.

five-year period. Section 3.2.4, Natural Gas & Wholesale Electric Market Hedging Strategy, provides a detailed discussion of PGE's natural gas and wholesale electricity hedging strategy.

Physical gas supply contracts for winter, summer, and annual delivery periods trade in a liquid wholesale market. PGE transacts in this market to secure physical gas at the AECO Sumas, and Rocky Mountain trading hubs. In addition to seasonal and annual purchases, PGE uses day-ahead purchases, off-system sales, and storage to balance the portfolio. In making unit commitment and dispatch decisions with respect to the Company's gas-fired plants, PGE compares market electric and gas prices, operating the plants when the market price for electricity is greater than the cost of purchasing gas and burning the fuel to produce power. This economic dispatch approach, enhanced by transportation and storage flexibility, reduces overall power supply costs.

3.2.3.4 Ongoing and Future Developments

Canadian sources—more than half of which are located in the Western Canadian Sedimentary Basin (WCSB)—will likely be the source of much of the future shale gas production. PGE will be able to access this WCSB gas through the Spectra and TransCanada Pipelines. Furthermore, increases in shale gas production in the Marcellus region (Northeast U.S.) will displace Canadian exports which have historically supplied that region. These shifts will likely impact flow patterns and result in additional gas supplies in Pacific Northwest markets.

Two possible expansion projects could impact PGE in the future. First, NW Pipeline is considering the Washington Expansion, which would increase capacity from Sumas southward along the I-5 corridor. Second, NW Natural is evaluating interest in the Trail West Pipeline, which would run between Madras and Molalla.[45] Both projects depend on firm customer commitments and would not see completion until 2018 or 2019 at the earliest. Given the high level of uncertainty with regard to the execution of these projects, PGE is monitoring developments at this time.

The combination of rapidly evolving gas supply and uncertainty about the pace and extent of economic expansion, oil prices, electric demand and fuel switching, emissions regulations, and other factors make future gas prices uncertain. PGE's Mid-Term Strategy's layering approach addresses these uncertainties, working to reduce year-to-year customer rate impacts associated with natural gas fuel costs.

Compared to firm pipeline transportation, storage provides much greater fueling flexibility for gas-fired resources. Storage at North Mist Expansion will allow PGE to maximize the capabilities of PW 2 to follow rapid changes in wind production and customer electricity demand. PGE is not aware of any other new storage facilities under development in the region.

In recent years, various entities have engaged studies to assess potential new gas storage development sites, as well as the more general topic of gas-electric interdependence. For instance, in 2013, the Western Gas-Electric Regional Assessment Task Force, under the Western Interstate Energy Board selected Energy and Environmental Economics (E3) and DNV GL to perform a study assessing the adequacy of the natural gas infrastructure in the western U.S. to meet the needs of Western utilities over a 10-year period. The two-phased study centered around two main questions:

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[45] The project previously operated under the name Palomar Pipeline and included other potential partners.

1. Will there be adequate natural gas infrastructure to meet the needs of the electric industry in the West approximately 10 years in the future?
2. Will the gas system have adequate short-term operational flexibility to meet increased volatility in hourly electric sector natural gas demand due to higher penetrations of variable renewable resources in the Western Interconnection?

E3 and DNV GL completed phase 1 in February 2014, and phase 2 in July 2014.[46] Generally, the studies found that under base case conditions, natural gas infrastructure was adequate to meet upcoming demand in the electric sector.

As discussed below, PGE also considers longer-term procurement of physical gas supply as a means of minimizing price risk for customers.

3.2.4 Natural Gas & Wholesale Electric Market Hedging Strategy

In past years, the Company, in cooperation with stakeholders, addressed near- and mid-term volatility through hedging using its mid-term strategy (MTS).[47] PGE has been executing transactions under the MTS since the first year of its implementation in 2007. The increasing reliance on gas as a long-term resource necessitated a fresh look at the gas planning approach. Beginning in 2015, PGE undertook a robust assessment to examine potential strategic and market approaches available for hedging and procurement options. The results of this analysis pointed to long-term hedging as an approach to reduce customer price variability associated with increasing natural gas generation. PGE defines long-term hedging as using hedging products with durations greater than five years—a strategy not currently deployed by PGE on behalf of customers. Current market factors presently make this an optimal approach.

Market prices are at relatively low historical levels. The shale revolution and the advent of efficient hydraulic fracturing technology dramatically impacted the aggregate supply-demand balance, market price, and gas flows. Of particular note, Western Canadian and U.S. Rockies gas production has outpaced increases in demand.

The confluence of low gas, oil, and liquids prices has created a favorable climate to pursue long-term transactions. The current market conditions will moderate over time. Supply surplus will drive demand via increased exports, gas-fired electric generation, and other uses. If supply surpluses continue despite increased demand, the market could see producers shutting in uneconomic wells.

To address this increasing exposure to gas commodity markets, PGE commissioned a study from the Berkley Research Group (BRG).[48] PGE defines long-term hedging as using hedging products with

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[46] For additional information on E3 and DNV GL study, see "Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective. Phase 1 Interim Report, March 2014," https://www.ethree.com/documents/E3_WIEB_Report_3-17-2014.pdf (retrieved on Sept. 15, 2016); *see also* Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective. Phase 2 Report, July 2014, https://www.ethree.com/documents/E3_WIEB_Ph2_Report_full_7-28-2014.pdf (retrieved on Sept. 15, 2016).

[47] This section only provides a quick overview of PGE's basis for conducting a gas strategy and hedging study. For a more thorough discussion of PGE's proposed long-term gas hedging strategy, see application, testimony, and exhibits in UE 308, PGE's 2017 Annual Power Cost Update Tariff docket.

[48] Berkeley Research Group, "Insights on Long-Term Natural Gas Hedging Strategies," report prepared for Portland General Electric May 2016.

durations greater than five years—a strategy not currently deployed by PGE on behalf of customers. Current market factors presently make this an optimal approach.

PGE also conducted broad market outreach to evaluate commercially available hedging options. Based on extensive feedback from the market, PGE concluded that a non-operating working interest—owned by the Company—is the best opportunity to hedge its long-term needs.

The non-operating working interest option allows PGE to provide customers a cost of service option for natural gas supply which provides insulation from structural changes in market prices. Limitations to alternative structures include either: (1) insufficient contract duration to provide an effective hedge beyond PGE's current Mid-Term Strategy; or (2) price levels that do not make them competitive with PGE's view of long-term gas prices.

A **non-operating working interest** is an ownership interest in a gas or oil well (or other mineral extraction business) that does not include participation in or any responsibility for the actual operation of the well or mine.

PGE's 2017 Annual Power Cost Update Tariff (UE 308) proposed four guidelines for long-term natural gas hedging:[49]

Guidelines 1 and 2 relate to any of the long-term gas hedging alternatives discussed in the filing:

1. Establish that the "Long-Term Projected Cost" must be at or below the comparable "Long-Term Benchmark Price".
2. Establish a maximum gas purchase commitment.

Guidelines 3 and 4 relate only to the non-operating working interest form of long-term gas hedging as discussed in the AUT filing:

3. Enter into transactions for properties that contain "Proved Reserves" or "Probable Reserves". Proved reserves are those quantities of gas, which can be estimated with reasonable certainty to be economically producible from known reservoirs and under existing economic conditions, operating methods, and government regulations. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.[50]
4. Establish limits within which the unit cost of the long-term gas is incorporated into PGE's annual power cost update (i.e., AUT filing).

With these framing guidelines, PGE investigated long-term hedging options including asset acquisitions in the United States and Canadian Rockies, or areas where the Company purchases its physical supply. PGE focused on the US Rockies because:

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[49] As part of the UE 308 proceeding, PGE agreed that it does not require approval of the guidelines.

[50] Netherland, Sewell, and Associates, Inc. at http://netherlandsewell.com/resources.html.

- PGE purchases gas from the market at hubs located in that region.
- PGE maintains long-term gas transportation agreements from this area.
- PGE views it as a mature, well-understood gas producing region.

Assuming a favorable regulatory decision from UE 308, the Company plans to pursue these cost-effective opportunities when they are available.

3.3 Environmental Considerations

3.3.1 Hydro Availability

PGE's hydro resources provide clean, carbon-free energy to customers. Additionally, hydro reservoirs bring valuable flexibility to the system across various timesteps, from automatic generator response for instantaneous fluctuations, to energy shifting between days.

In 2021, PGE projects hydro resources to be approximately 17 percent of the Company's fleet on an available energy basis. The quantity has declined since 2005, primarily due to the expiration of the original contracts for the Mid-Columbia (Mid-C) hydro projects. Regionally, however, hydro generation remains a dominant factor in determining market power prices.

Due to short and long-term weather patterns, streamflow changes have impacted the regional hydro system's generation and flexibility. Historical streamflow data shows a wide variation in the quantity and timing of flows in the Pacific Northwest. As discussed in Section 3.3.2, Climate Change Study, analysts expect changes to global temperatures and weather patterns to impact the timing, quantity, and characteristics (rain vs. snow) of regional precipitation, as well as the timing of the snowmelt.

In addition to impacting power prices, a shift to timing of precipitation and snowmelt can alter the ability of the hydro system to provide flexible capacity. A reduction to the flexibility of the system may increase the potential for renewable curtailment.

Many factors can impact regional hydro generation, including habitat, flood control, and recreation requirements. The operation of Canadian reservoirs under the Canadian Entitlement Allocation Extension Agreement (which expires in 2024) may also affect hydro generation.

3.3.1.1 Incorporation into IRP

As in previous IRPs, PGE examines the impact of very low hydro conditions on market prices through the Low Hydro Future analysis in AURORA, which uses the EPIS PNW Hydro based on 1937 streamflows, a common view of regional critical hydro. PGE applies the Low Hydro profile to the region for 2020-2050, including the Company's plants. See Chapter 10, Modeling Methodology.

The capacity assessment incorporates an estimate from E3 of the impacts of variability of Mid-C capacity due to hydro conditions. The RECAP model incorporates this data as discussed in Chapter 5, Resource Adequacy.

3.3.1.2 Future Planning Considerations

PGE will continue to review the hydro assumptions and prioritize projects for future IRP cycles. A few of the items PGE is reviewing include:

- Potential impacts on regional hydro generation, regional prices, and PGE's hydro resources due to changes in precipitation and snowmelt patterns.
- Assumptions for 1937 critical hydro used in the Low Hydro future.
- Potential impacts due to the expiration of the Canadian Entitlement Allocation Extension Agreement.

3.3.2 Climate Change Study

PGE commissioned a study titled “Climate Change Projections in Portland General Electric Service Territory” (Climate Study) from the Oregon Climate Research Institute (OCCRI) to better understand how climate change may affect local electrical demand and hydro streamflows. The Climate Study, included as Appendix E, Climate Change Projections in Portland General Electric Service Territory, documents the robust evidence regarding the anthropogenic forces on the Earth’s climate system increasing the Earth’s average temperature.

3.3.2.1 Climate Adjusted Streamflows

The Climate Study examined how streamflows may be impacted at watersheds where PGE operates, or contracts for, hydro generation. Relying on a survey of previously published work, the Climate Study documents how experts expect streamflows to generally shift from spring to winter, as winter rain at high elevations diminishes snow available during spring runoff.

Figure 3-10 projects change in combined monthly average total runoff and baseflow in inches (the primary determinants of streamflow) over the entire basin for the Deschutes River at Round Butte (left), Clackamas River at Mills Dam (center), and Columbia River and Wells Dam (right) for a medium emissions scenario and three time periods (2020s, 2040s, 2080s).[51]

The Climate Study projected climate change induced declines in April 1 snowpack across the Columbia River Basin. Regions where average winter temperatures are close to the freezing level are particularly sensitive to the streamflow impacts. These regions include the Cascade Range.

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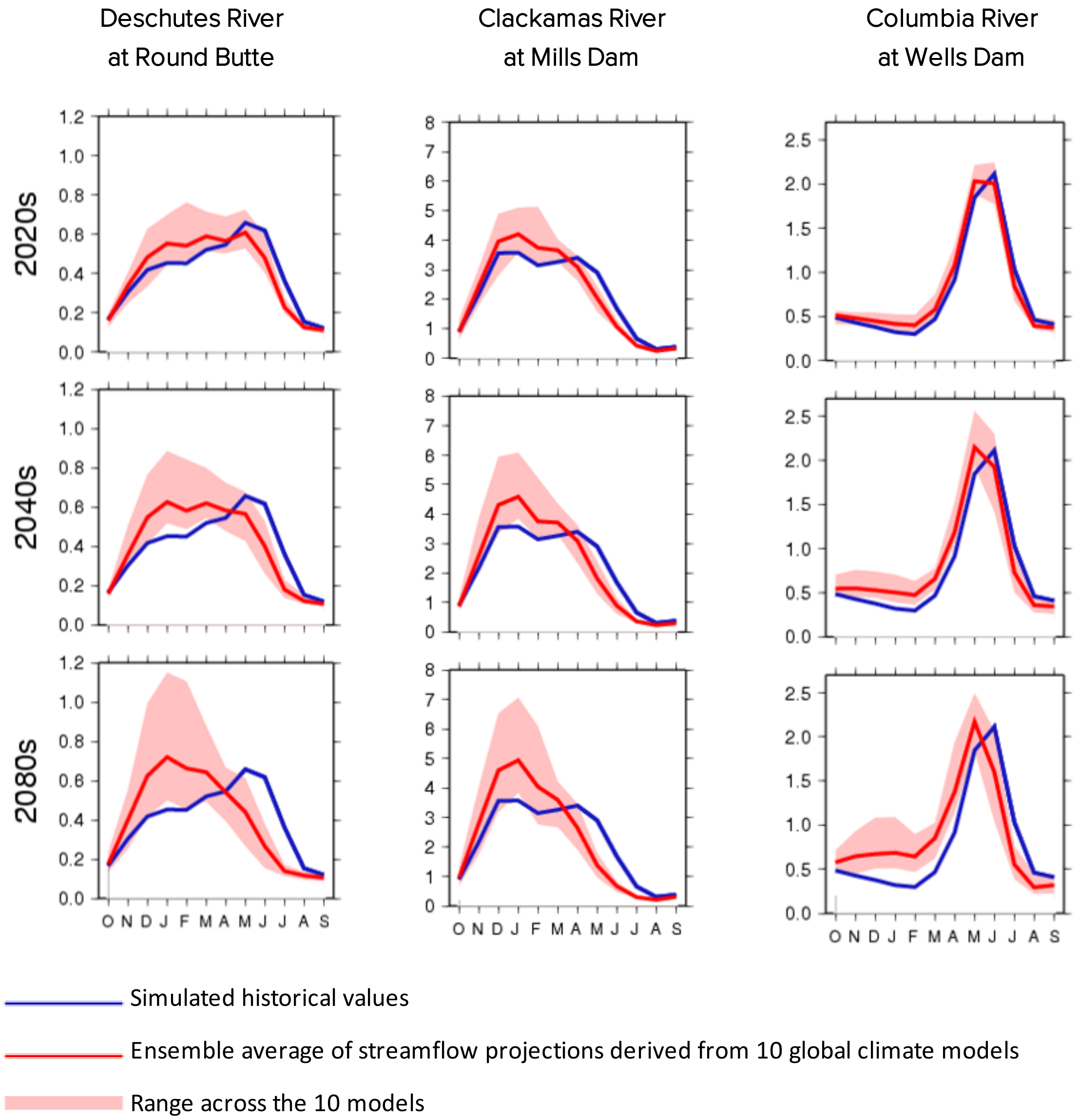
[51] Columbia Basin Climate Change Scenarios Project, http://warm.atmos.washington.edu/2860/.

FIGURE 3-10: Climate adjusted streamflows



3.3.2.2 Climate Adjusted Loads

The Climate Study included daily temperature forecasts focused on PGE’s service territory. The temperature profiles are the result of global climate modeling under two emission scenarios focused on the Pacific Northwest. The two emission scenarios include a ‘business as usual’ referred to as representative concentration pathway (RCP) 8.5, and a second scenario, RCP 4.5, in which a moderate effort to curb global emissions leads to reduced annual emissions relative to present levels. Under RCP 8.5, the researchers estimate that average Pacific Northwest temperatures will increase by eleven degrees (F) by 2100. Under RCP 4.5, the average increase to Pacific Northwest temperatures is limited to six degrees (F).

OCCRI researchers generated simulated temperature data specific to PGE’s load service area by using statistical downscaling techniques. Downscaling resolves global climate modeling results to spatial resolution of 6-km while recognizing the climactic effects of local topology and weather.

OCCRI delivered to PGE the daily temperature results from twenty downscaled models for both emission scenarios for years 1950-2100.

PGE has used OCCRI's data to study how changes in climate 1950-2100 would affect system energy and peak load requirements. PGE characterized the OCCRI data according to the relevant heating degree day and cooling degree inputs for PGE's energy and peak load forecast models. The effect of climate adjusted weather trends can be compared to the simulated normal conditions (defined using OCCRI data from 2000-2014, consistent with PGE's current load forecast model assumptions of a rolling 15 year weather normal).

Figure 3-11 shows how climate change may affect PGE's normal system load conditions under RCP 8.5 business as usual emission scenario. The figures display, in MWa, the deviation from normal annual and seasonal loads that would occur on today's system given adjusted climate trends 1950-2100. The energy output (in blue) shows the average system load produced from the twenty downscaled models. The simulated energy output includes both the impact of long term climate change and the cyclical nature of shorter weather cycles. The trend line (in red) fits to the average output. The Min and Max trends (in teal) illustrate the confidence intervals in the simulation. Specifically, the trends are fitted approximations of the annual maximum and minimum from the downscaled ensemble.

Of note in Figure 3-11, is the decrease in winter energy requirements and the increase in summer energy requirements. On an annual basis, given PGE's current system, PGE forecasts these climate trends to largely offset each other leading to minimal changes in annual energy requirements.

FIGURE 3-11: Climate adjusted PGE energy requirements

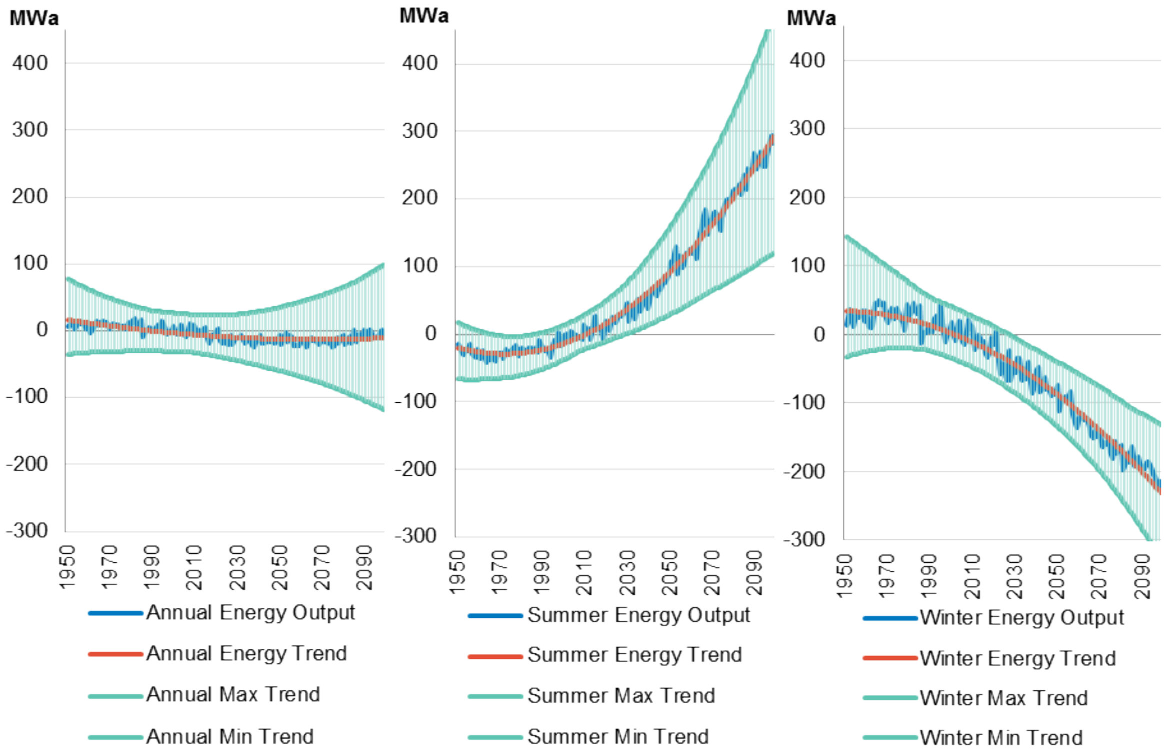
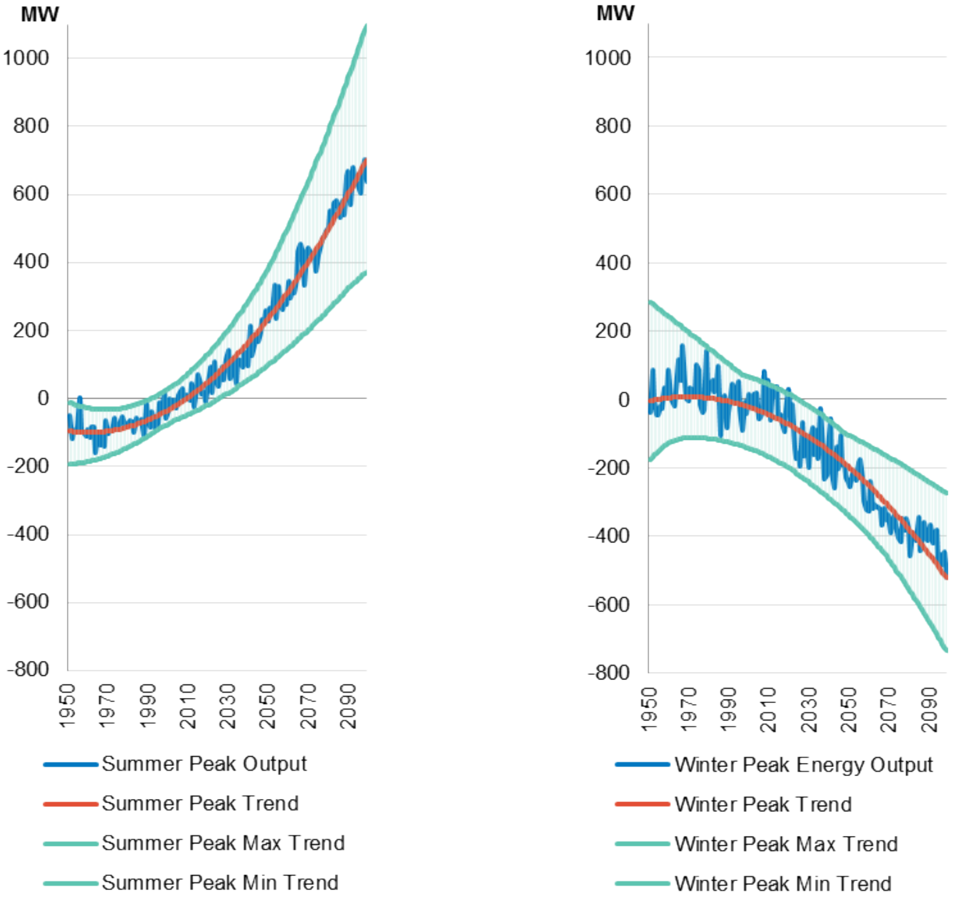


Figure 3-12 shows how climate change might affect PGE's normal system peak load conditions under the RCP 8.5 business as usual emission scenario. The figures display, in MW, the deviation from normal seasonal peaks that would occur on today's system given adjusted climate trends 1950-2100. The magnitude of summer peaking events would increase by approximately 600 MW by 2100. Winter peaks, would decrease by approximately 500 MW by 2100.

FIGURE 3-12: Climate adjusted PGE peak demand



3.3.2.3 Incorporation into IRP

PGE identified load futures in which energy and peak forecasts capture the magnitude of potential demand introduced by climate change. As illustrated in Figure 3-13 and Figure 3-14, the IRP High load scenario includes a significantly higher annual energy demand and peak than either the RCP annual trend or the RCP summer only trend. PGE created these futures to capture a range of potential load drivers including economic and population growth, increased electric vehicle adoption and greater electrification.

FIGURE 3-13: PGE energy futures compared to climate trends

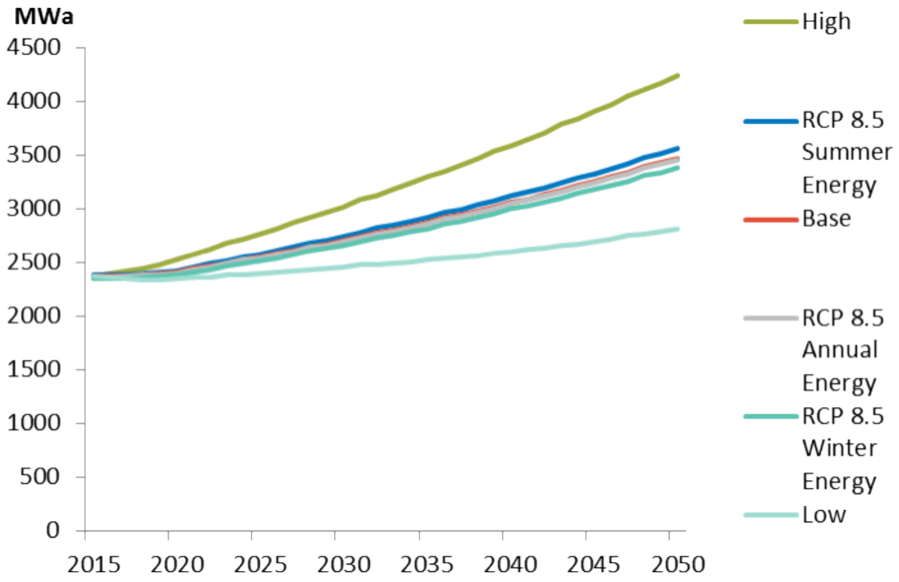
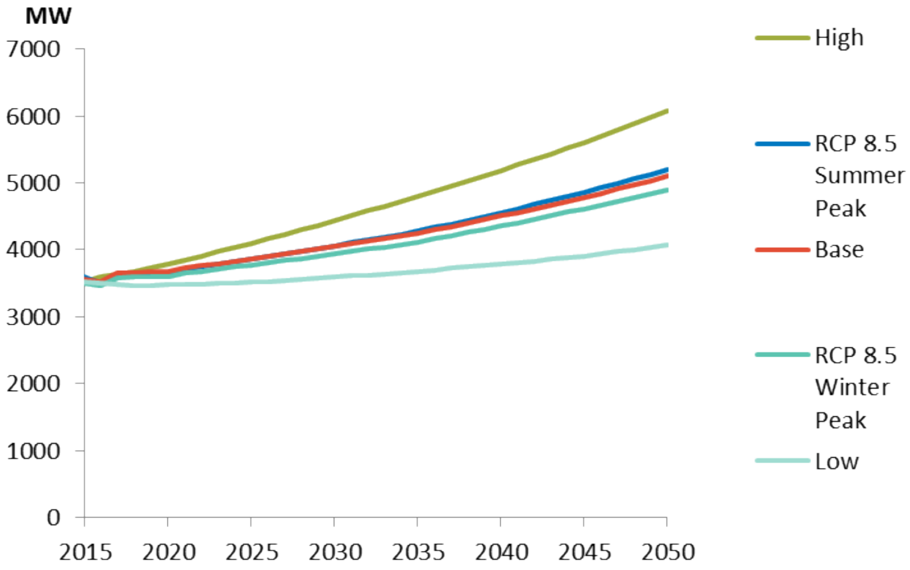
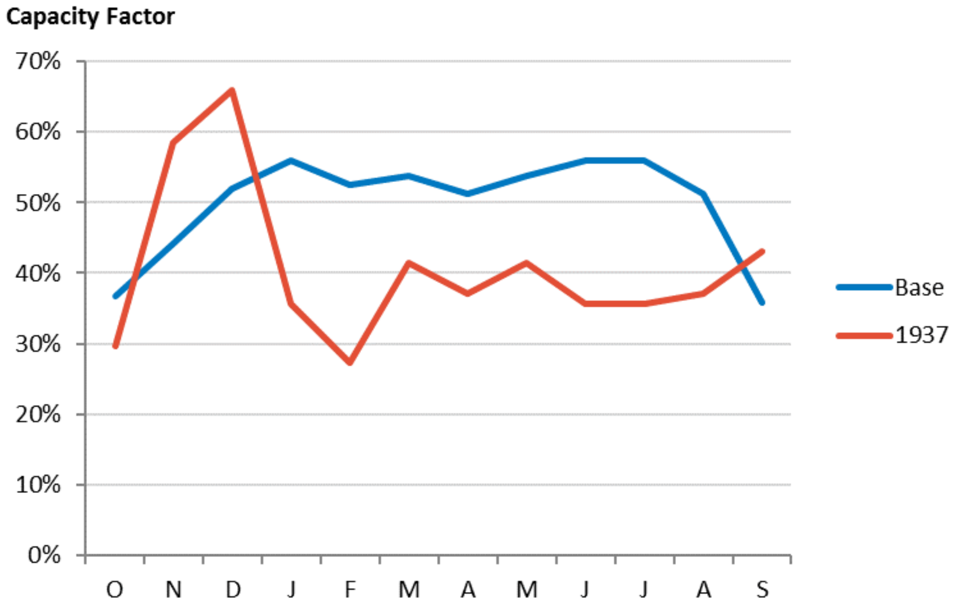


FIGURE 3-14: PGE peak futures compared to climate trends



PGE identified hydro futures that capture the declining hydro production associated with climate change. Figure 3-15 shows the capacity factor at Clackamas River dams in 1937 compared to the base case assumption. The 2016 IRP tests this hydro future to see, amongst other things, how reduced availability of hydro generation (and a different runoff shape) will affect PGE's generation portfolio.

FIGURE 3-15: Clackamas 1937 hydro shape vs. base shape



3.4 Market Considerations

Energy markets are undergoing major operational changes to maintain system reliability while accommodating increasing shares of renewables and growing demand. PGE is an active player is such efforts which will eventually result in lower transaction costs to deliver electricity. This section describes PGE's progress so far in three major regional programs:

- Northwest bilateral subhourly market,
- Western Energy Imbalance Market (EIM),
- Western ISO market.

3.4.1 Bilateral Subhourly Market

The subhourly bilateral market in the Northwest offers PGE the option of buying, selling and transmitting energy on shorter time intervals than the traditional hourly market. This market has the potential to allow PGE to access additional flexibility to respond to unexpected changes in power generation and demand. However, this potential has yet to materialize as the subhourly market in the Northwest continues to suffer from a lack of liquidity.

3.4.1.1 BPA Support for Subhourly Scheduling

On October 21, 2014, Bonneville Power Administration (BPA) made it possible for transmission customers to schedule energy on a 15-minute basis in addition to the historical hourly scheduling and trading windows. By offering 15-minute scheduling, BPA conformed to the Open Access Transmission Tariff requirements included in FERC Order 764, which PGE and other FERC-Jurisdictional transmission service providers were required to meet, and helped remove barriers to integrating variable energy resources (VERs) on their system.

As BPA's transmission system facilitates the majority of bilateral transactions in the Northwest, their offering of 15-minute scheduling was critical in allowing a subhourly market to develop. Unfortunately, while BPA continues to offer 15-minute scheduling, it remains underutilized and a robust bilateral subhourly market has yet to develop in the Northwest.

3.4.1.2 PGE Participation in BPA Subhourly Scheduling for Wind Integration

PGE's owned wind resources, Biglow Canyon Wind Farm (Biglow) and Tucannon River Wind Farm (Tucannon), are physically located, and also electrically metered, inside BPA's BAA. For the BP-16 rate period, PGE elected to purchase BPA's "30/15 committed scheduling" variable energy reserve balancing services (VERBS) product.

Under the 30/15 committed scheduling option, PGE makes four wind schedule changes per hour. PGE submits a schedule 30 minutes prior to each 15-minute schedule interval for the forecast of each plant's output. PGE bases the forecast on BPA's persistence forecast, which is a one-minute average of generation from 31 to 30 minutes before each scheduling period. For example, PGE would submit a schedule for Biglow at 2:30 p.m. for generation that will occur from 3:00 p.m. to 3:15 p.m. The Company bases the schedule on a forecast that derives from the 1-minute average of Biglow's generation from 2:29 p.m. to 2:30 p.m.

PGE selected 30/15 committed scheduling to implement a step-wise approach toward more frequent scheduling and dispatch of the Company's plants. Under 30/15 committed scheduling, PGE uses Company hydro and thermal resources to manage the intra-hour variability of Company wind resources on a 15-minute basis. This increased dispatch activity gives Operators experience in moving the power output across multiple resources (including thermal resources) for system flexibility. This experience has been complementary to the within-hour markets that are developing in the region.

3.4.1.3 Self-Integration of Wind

After October 1, 2017, PGE intends to dynamically transfer via pseudo-tie its owned wind resources out of BPA's Balancing Authority Area (BAA) and integrate the variability using PGE's own resources (i.e., full self-integration). The Company expressed this intent publicly, beginning with BPA's Generation Inputs Workshop. PGE formally requested dynamic transfer capability from BPA on November 11, 2015. Then, in January 2016, the Company made the necessary formal requests to BPA to begin the process of establishing the dynamic transfer of both the Biglow and Tucannon resources out of the BPA BAA.

The Company is taking all steps to attain a reasonable level of confidence in BPA's ability to complete its pseudo-tie request by October 1, 2017. Particularly, PGE is advocating for inclusion in three seasonal studies/reviews that require completion prior to establishment of a pseudo-tie:

1. BPA's Dynamic Transfer Capability Study (typically completed in the spring)
2. WECC's Remedial Action Scheme Review (typically completed in the fall)
3. BPA's Local Integration Test (typically completed in the fall)

PGE will continue to work with BPA to accomplish the pseudo-tie needed for the Company's self-integration of its owned resources.

3.4.2 Western Energy Imbalance Market (EIM)

In September 2015, PGE announced its intent to explore next steps for participation in the Western Energy Imbalance Market (EIM). On November 20, 2015, the California Independent System Operator (CAISO) filed the Implementation Agreement executed by PGE and the CAISO with the Federal Energy Regulatory Commission (FERC). Pursuant to the Implementation Agreement, PGE is preparing for a market entry date of October 1, 2017.

The Western EIM is a voluntary, balancing energy market operated by CAISO that optimizes generator dispatch within and between BAAs every 5 minutes. The Western EIM's operations began November 1, 2014. PacifiCorp and Nevada Energy are active participants in the CAISO-operated market. Puget Sound Energy and Arizona Public Service announced planned market entries in 2016.

In general, the Western EIM can facilitate subhourly optimization of load-resource balancing across a wide-area footprint. In this market, CAISO, the market operator, receives load-resource plans from each market participant for each market scheduling interval. Along with this load-resource plan, each participant also submits the dispatchable range and associated price curve for each resource it can make available to the market operator for dispatch within each market interval. Using this information, the market operator re-dispatches the resources made available to it, while respecting available transmission flows and individual resource economics.

In its IRP Updates and future IRPs, PGE will provide more details regarding its participation in the EIM and the benefits produced by the Company's involvement in this market.

3.4.3 Proposed Western ISO Market

CAISO is currently moving forward with plans to develop and implement a regional energy market. The proposed regional energy market would offer the opportunity to extend the boundaries of CAISO's current day-ahead and real-time energy market and forward resource adequacy assessments, as well as their transmission and balancing authority operations, to encompass additional balancing authorities, participating transmission owners, and market participants in the Western Interconnection. The market would be an expansion of scope beyond the real-time Energy Imbalance Market. CAISO's proposed regional energy market targets reducing energy costs for consumers, enhancing coordination and reliability of western electric networks, facilitating the least-cost integration of renewable resources, reducing carbon emissions, and enhancing regional transmission planning and expansion.

PacifiCorp and CAISO signed a memorandum of understanding in April 2015 committing the two entities to explore these benefits, as well as the governance, tariff structures, implementation costs, and other frameworks that would need to evolve in order to implement the initial regional market across their respective systems. Since the passing of Senate Bill 350[52] in October 2015, CAISO and PacifiCorp have launched an in-depth stakeholder and benefits-study process[53] to inform that

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[52] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[53] https://www.caiso.com/informed/Pages/BenefitsofaRegionalEnergyMarket.aspx

exploration. When beginning the initiative, CAISO and PacifiCorp targeted January 2019 as the go-live date for the expanded regional energy market and committed to provide biweekly updates to interested parties on interim implementation milestones.[54]

As PGE is currently a participant in CAISO's day-ahead and real-time energy markets and a future participant in the Western EIM, a co-owner of transmission facilities with PacifiCorp, and an adjacent balancing authority and member of reserve sharing and transmission planning bodies with PacifiCorp, the implementation of a regional market between CAISO and PacifiCorp will affect PGE's operations; however, at this stage in the market development, it is not clear to what extent. PGE will continue to monitor the market developments and assess impacts as the regional energy market implementation details evolve.

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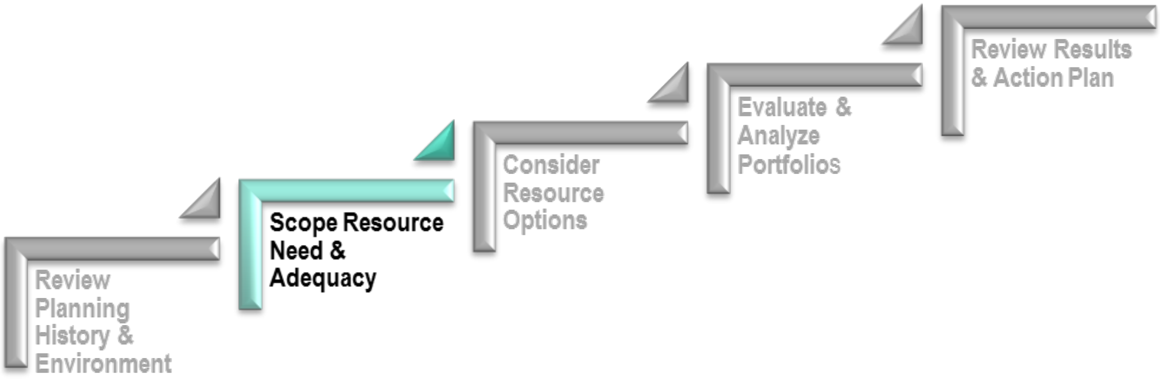
[54] https://www.caiso.com/Documents/Bi-WeeklyRegionalIntegrationUpdateCallsStartingJanuary5_2016.htm

Part II. Resource Need Assessment



CHAPTER 4. Resource Need

In this chapter, PGE describes its reference case load growth forecast, the methodology to develop this forecast, and high and low load growth scenarios. Chapter 4 also includes discussions regarding the treatment of five-year opt-out customers in the IRP, the potential impact of electric vehicle adoption, and the types of operating reserves PGE must meet on the system in addition to meeting demand.

Chapter Highlights

- ★ **The Company's reference case load forecast shows long-term energy demand growth rates of 1.2 percent annually in the long-term, with peak demand growing 1.0 percent in winter and 1.2 percent in summer.**
- ★ **Current plug-in electric vehicles (PEV) adoption trends suggest that load associated with PEVs will not be a near-term driver of additional load growth.**
- ★ **PGE's resource need includes the need to supply operating reserves for three percent of its load and three percent of its generation, as required by Western Electricity Coordinating Council Standard BAL-002-WECC-2.**
- ★ **PGE does not plan long-term resources for five-year opt-out customers.**

4.1 Load Forecast

PGE's assessment of resource need relies on expected energy and capacity requirements identified in the load forecast. This chapter provides an overview of the forecast used for this IRP filing and the methodology used in its development, including refinements made in response to a third-party review of PGE's forecast methodology.

4.1.1 Overview

PGE's resource need analysis for this IRP uses the June 2015 long-term system load forecast.[55] For IRP purposes, PGE identifies annual energy needs under its reference case (i.e., most likely case) load growth. The Company also assesses its annual energy needs under high-load growth and low-load growth sensitivity forecasts based on standard error from the reference case.

A key determinant of load growth is the economic landscape of PGE's service territory. For Oregon, the economic landscape has continued to improve since the filing of the last IRP, with Oregon employment surpassing prerecession peaks and reaching growth rates over 3 percent. PGE's industrial sector performance and strong in-migration[56] have driven energy deliveries growth rates above those seen at a national level.[57]

In the short-term (2017 to 2021), PGE's load growth reflects the pace of economic growth in Oregon as forecast by the Oregon Office of Economic Analysis (OEA). It also reflects expansions currently underway among certain large customers. The long-term outlook for future economic, population and load growth in Oregon and PGE's service territory is also positive. The pace of employment growth slows somewhat in the long-term as demographic trends, including an aging population, weigh on labor force growth; however, the OEA expects Oregon employment and population growth to outpace the national average and be particularly strong in urban areas.

Figure 4-1 displays annual load and peak winter and summer demand under PGE's reference case forecast from 2017 through 2050.[58] Annual energy growth averages 1.2 percent in the long-term (2022-2050). In PGE's reference case, summer peak demand grows at a somewhat faster rate than winter peak demand (1.2 percent vs. 1.0 percent for 2022-2050) based, primarily, on the changing behavioral response of PGE's customers to warm summer temperatures. The expected summer peak demand surpasses the expected winter peak demand in 2035. PGE represents annual peak demand using 1-in-2, or expected (normal) weather conditions, meaning that there is a 1-in-2 or 50 percent probability that the actual peak load will exceed the forecasted peak load during any given period. PGE load forecast, as presented in this chapter, includes estimated EE savings.

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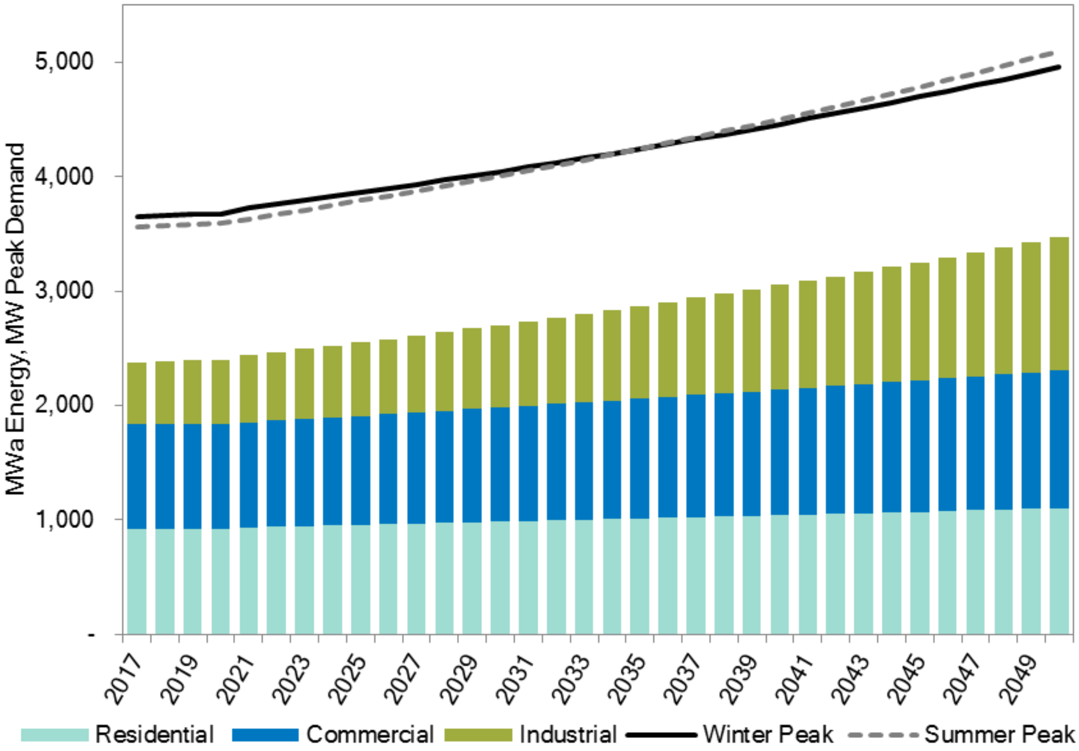
[55] PGE based its reference case load forecast on the Oregon Office of Economic Analysis May 2015 Economic Forecast, Global Insight's May 2015 U.S. Economic Forecast and actual energy deliveries through April 2015.

[56] In-migration refers to relocation of residents to a new area. In PGE's service territory, this includes migration from other states (and countries) as well as rural to urban migration within the state of Oregon.

[57] PGE and national level growth rates described in detail in Section 4.1.4, Class Level Trends and Forecasts.

[58] The load forecast in Figure 4-1 includes long-term opt-outs, which are not included in the IRP analysis.

FIGURE 4-1: Reference case forecast by class: 2017 to 2050



4.1.2 Third Party Review of Forecast Methodology

PGE has used its load forecast model for many years with only relatively minor changes. The load forecast model has an established history and has performed well; however, the relationships between energy deliveries and drivers for demand change over time. Consistent with its 2013 IRP Action Plan, in late 2014, PGE issued a Request for Quote (RFQ) and selected Itron to evaluate the existing load forecast model and make recommendations based on industry practice to improve PGE models, relationships in models, and forecast processes. Itron's evaluation focused on modeling weather in short-term energy models, PGE's long-term energy forecast approach, PGE's peak demand forecast approach, and overall complexity of models and processes.

Itron found PGE's general approach to be consistent with industry standards and made several recommendations to improve alignment with industry practice. The recommendations seek to reduce complexity in the models and increase interpretability; not to alter the trajectory or magnitude of the forecast.

The following information provides a description of PGE's general approach to each segment of its load forecast and the results of Itron's review pertaining to that segment.

Itron presented their findings at the April 2, 2015, IRP Public Meeting. See the Itron Presentation for more details.

4.1.2.1 Short-Term Forecast Models

PGE's short-term (five-year) models are regression-based equations, which predict energy deliveries for 25 forecast groups as a function of weather and economic drivers. For six of the seven residential customer groups, these models consist of use-per-customer and customer equations. PGE estimates total energy deliveries directly for each of the non-residential forecast groups.

The load forecast models estimate energy deliveries to their respective forecast groups as a function of weather and group-specific economic drivers. PGE reestimates the load regression equations at least once per year to incorporate recent historical deliveries and economic data into the forecast. Each forecast update uses the most recent economic data available in tandem with the coefficients from the load regression models to develop the retail energy forecast. In addition, customers who are large energy users provide specific operational information, direct inputs, and, if available, forecasts of energy use. PGE uses this customer information along with company and industry data from third-party sources to augment the regression model forecast.

PGE made refinements to the energy models with respect to recommendations on the characterization of weather response[59] .The Company also extensively analyzed the forecast drivers and estimation periods to capture changing relationships between energy consumption and the sector drivers. The basis for most models is now shorter estimation periods to align with changes in the trajectory of energy consumption or changes in relationships with respect to the economic drivers and end-use appliance saturations.

4.1.2.2 Long-Term Forecast Models

Historically, PGE based its long-term forecasts on energy growth rates derived from averaging the growth occurring in the long-term historical series with that of the mid-term historical series. The concept of long-term growth rates is to capture the convergence as growth in energy deliveries becomes agnostic to business-cycle trends and customer specific expansions. In lieu of this simplified approach to the estimation of long-term growth rates, Itron recommended the development of long-term regression models for higher level customer groupings than used in the short-term models. PGE developed these models by service delivery voltage – Residential, Secondary, and Primary – and incorporate long-run economic (equilibrium) growth rates, which reflect structural changes in employment levels due to long-term demographic trends, but do not predict future business cycles. PGE assumes energy deliveries to Transmission and Street Lighting voltage service customers are constant into the future.

4.1.2.3 Peak Demand Forecast Model

PGE refined its peak demand forecasting model by implementing a regression-based approach to the modeling of monthly net system peak demands. Previously, PGE estimated peak demands using a class load factor build-up approach[60] . The regression approach estimates monthly and seasonal

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[59] Specifically, the use of varying set points on heating and cooling degree days to be included in multi-part weather splines allows for a non-linear response. Varying set points also allows for differences in response between customer classes based on a "comfort" index.

[60] The load factor build-up approach estimates peak demands by applying the historical ratio of peak demand to average demand (or load factor) to the energy (average demand) forecast. This approach applied by voltage delivery class by month.

peak demand as a function of daily peak heating degree days, cooling degree days, lagged cooling degree days, average wind speed and monthly energy interacted with season. Incorporation of weather variables allows for scenario analysis and normalization of historical peaks. Forecast assumptions of normal peaking weather are consistent with energy models, using a 15-year average of historic peaking events.

Itron's recommendations to incorporate regression analysis into long-term class level deliveries and peak demand models are particularly relevant to the IRP process. PGE made these changes beginning with the June 2015 forecast used for this IRP analysis. PGE discussed this methodological change in detail at the Load Forecasting Technical Workshop on July 15, 2015 and presented results at the second Public Meeting held on July 16, 2015.

4.1.3 Key Assumptions and Drivers

The following are the key assumptions and trends supporting PGE's forecast:

4.1.3.1 Weather

Weather, specifically ambient temperature, is the largest factor affecting customer electricity demand in the residential and commercial sectors. Industrial loads tend to be less weather sensitive. PGE uses rolling 15-year average weather assumptions as inputs to both the energy and peak models and for the weather-normalization of actual deliveries.[61] PGE also uses a number of specific weather variables in the energy and peak models, including heating and cooling degree days (HDD and CDD) at varying set points, for current and lagged periods, and average wind speeds.

4.1.3.2 Economic Outlook

PGE relies primarily on OEA and IHS Global Insight for economic forecast inputs.

- Real GDP[62] Growth. The current IHS Global Insight economic forecasts project real GDP increasing at 2.6 percent through 2020 before reverting to a longer-term average of 2.3 percent.[63]
- Oregon nonfarm payroll (employment) growth is a fundamental economic driver. The OEA forecast projects a 1.5 percent average annual growth rate over the next ten years, with growth as high as 3 percent in the very near-term, slowing to 1 percent to reflect long-term demographic trends.

4.1.3.3 Population Forecast

The OEA expects Oregon's position as a magnet state and the general trend of Western states growing faster than the U.S. national average to continue. The OEA currently forecasts population growth of 1.4 percent in PGE's seven-county region and 1.2 percent state-wide compared to 0.8 percent for the nation.

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[61] PGE based the 2016 IRP load forecast on the 15-year average weather observed from 2000 through 2014 at the National Oceanic and Atmospheric Administration's (NOAA) Portland International Airport weather station.

[62] Gross Domestic Product.

[63] IHS Global Insight Long-Term Forecast 30-Year May 2015.

4.1.3.4 Industrial Customer Trends

PGE bases large industrial customer expansions and new manufacturing facilities on the best known information and expectations for its customers and their industries in the short-term. The Company embeds this information in the primary service growth rates for the long-term growth rates.

- A key driver of future industrial loads is growth in the high-technology sector, particularly led by semiconductor manufacturing.
- The OEA forecasts that Oregon will outpace the national average with respect to manufacturing employment in the coming decade.
- The short-term forecast (2017-2021) reflects current customer expansions and planned future projects. PGE's forecasting team coordinates with internal resources, including Key Customer Managers and PGE's Corporate Finance Group, which perform credit-risk analysis for these large customers to inform energy deliveries assumptions.

4.1.3.5 Energy Efficiency (EE)

Oregon has a long history of EE with programmatic savings back into the 1990s. Historic energy usage data used in regression models, therefore, capture the impact of this "embedded" historical EE. As a result, PGE's approach to accounting for EE is two-fold:

- PGE determines incremental savings, above and beyond those embedded in historical trends, as those programs enabled by SB 838.[64]
- PGE uses forecasts provided by the Energy Trust to subtract these savings from the regression model results in the short-term model.

4.1.3.6 Plug-in Electric Vehicles (PEVs)

PGE's load forecast does not include any explicit adjustments to capture the potential for accelerated adoption of PEVs. The Company implicitly incorporates PEV charging loads are implicitly incorporated into the load forecast as components of the load in sectors where charging occurs. Currently, load related to electric vehicle charging in PGE's service territory is small due to the low PEV saturation rate. Section 4.2, Plug-in Electric Vehicles, discusses PEVs in more detail.

4.1.3.7 Customer-sited Solar

PGE's load forecast does not include any explicit adjustment to historical loads to account for customer-sited solar, nor does the forecast contain assumptions about the potential for accelerated growth rates of this resource. Similar to the treatment of PEVs, PGE implicitly incorporates customer-sited solar resources into the load forecast as load modifiers in the sectors in which solar systems have been installed. Chapter 7, Supply Options, discusses PGE's distributed solar market potential study performed by Black and Veatch and efforts underway to update the data in that study. (See also Appendix F, Distributed Generation Studies.)

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[64] In 2007, Senate Bill 838 extended funding for energy efficiency beyond the 3% level enacted by 1999's SB 1149 for additional cost-effective electric efficiency. This represents an incremental increase in the program levels applied to PGE customers beginning at this point in time.

4.1.4 Class Level Trends and Forecasts

PGE's service territory encompasses primarily metro areas positioned for strong long-term growth compared to other regional and rural economies. Historically, there were brief periods (one to five years) during which demand for electricity in PGE-served areas declined due to boundary changes, business cycles, or departures of large customers from the system. PGE's overall demand has rebounded and grown over time based on macroeconomic and fundamental drivers. The Company expects this trend to continue in the future.

The load forecast reflects the expected continuation of the following trends which will, over time, alter the composition and characteristics of various customer sectors:

4.1.4.1 Residential Sector

Customer growth of 1.1 percent offset by declining use-per-customer of -0.5 percent is driving the residential sector energy deliveries. PGE expects customer growth to continue in response to population growth in the Company's service area. Declining use per customer reflects Oregon's history of energy efficiency and end-use trends as determined by customer preference as well as market forces. Since 1990, residential use per customer has fallen 22 percent, or an average of 0.9 percent per year. Changes in end use – primarily increasing air conditioning penetration combined with declining heating penetration – will alter diurnal and seasonal load shapes. PGE's long-term model forecasts residential energy deliveries to grow at an annual average rate of 0.6 percent. The Company is forecasting the residential sector to be its slowest growing sector. This impacts the sector's share of system load, which fell from 43 percent to 39 percent between 1985 and 2015, and is forecast to decline to 36 percent by 2030.

4.1.4.2 Commercial Sector

Commercial sector loads move alongside residential customer growth as demand for services, particularly healthcare and education, as well as general retail, food stores, and restaurants continues to expand with population growth. Energy efficiency programs targeting the commercial class and equipment standards dampen growth. PGE bases its long-term commercial forecast model upon Oregon total non-farm employment growth. The energy deliveries forecast is 0.9 percent. As a share of deliveries, commercial loads made up approximately 38 percent of system loads in 2015 and are forecast to decline, although very slowly, as industrial growth outweighs growth in the commercial and residential sectors.

4.1.4.3 Industrial Sector

Industrial sector energy demand exhibits more load volatility and uncertainty, as industrial customers react to changing market conditions and business cycles. PGE's 20 largest industrial customers account for approximately three-quarters of industrial load. The Company forecasts industrial energy deliveries to grow at an annual average rate of 2.6 percent. Due to this relatively faster growth rate compared to other sectors, the forecast projects the industrial share of deliveries to grow from 23 percent in 2015 up to 26 percent by 2025, and 30 percent by 2040.

4.1.4.4 Street Lighting

The street light energy forecast assumes no growth in long-term energy deliveries, which reflects conversion to LED-based lamps offsetting growth in street lamp count.

4.1.4.5 Seasonality

PGE has historically been winter peaking; however, in 2002, the Company experienced its first summer annual system peak. Since 2002, PGE has experienced five additional summer peak years. PGE's forecast reflects summer demand growing faster than winter demand, due to increasing cooling system penetration, and decreasing electric space and water heat penetration. Load composition also influences seasonal peaks as industrial loads, which are growing more quickly than the system total, may be sensitive to cooling needs but rarely impacted by heating degree days. While the expected summer peaks do exceed winter peaks within this forecast horizon, a shift to higher overall energy consumption in the summer is not expected as the forecast continues to reflect the expectation for more heating days than cooling days in the Pacific Northwest driven by both intensity and duration of the heating season.

4.1.5 Load Growth Scenarios

The Commission's IRP Guideline 4b, as set forth in Order No. 07-002, requires an analysis of high- and low-load growth scenarios in addition to stochastic load risk analysis, with an explanation of major assumptions. PGE addresses stochastic load risk analysis in Chapter 5, Resource Adequacy, and describes load growth impacts for PGE in Chapter 12, Modeling Results.

In addition to a reference case forecast, PGE projects high and low long-term growth cases. Monthly energy demand by sector is individually forecast to grow at the mean (average) rate, with the high- and low-load growth cases constructed using plus one (+1) standard error for the high case and minus one (-1) standard error for the low case[65].

TABLE 4-1: 2021 Forecast case

Forecast Case	Energy (MWa)	Growth Rate	Winter Capacity	Growth Rate	Summer Capacity	Growth Rate
Base	2,439	1.2%	3,730	1.0%	3,634	1.2%
High	2,530	1.7%	3,784	1.6%	3,701	1.7%
Low	2,348	0.6%	3,481	0.4%	3,446	0.5%
High (+2)	2,625	2.3%	3,946	2.2%	3,837	2.3%
Low (-2)	2,253	-0.4%	3,338	-0.7%	3,321	-0.4%

These cases do not reflect specific changes to assumptions for customer usage patterns or consumption rates, or shifts in aggregate demand due to fundamental pattern changes (e.g., sustained out-migration, rebound in space heat penetration or renaissance of certain industries).

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[65] PGE develops two additional growth scenarios using plus and minus two standard errors.

Rather, these high and low cases serve as demand boundaries, or “jaws”, and are sufficiently large to incorporate a departure from the reference forecast caused by changes to the broad economic character of the region, other long-term trends, or technologies that may affect future load growth. Brief excursions outside the boundaries could still occur in the short run due to the cyclical nature of the economy.

In addition, PGE created a scenario analysis reflecting the impacts of changes in long-term climate change as predicted by the Oregon Climate Change Research Institute (OCCRI) in the climate change study provided in Appendix E, Climate Change Projections in Portland General Electric Service Territory. Chapter 3, Planning Environment (with the OCCRI analysis), discusses this climate change analysis; however, for purposes of IRP analysis, the standard error based "jaws" provided in Table 4-1 appropriately bookend load forecast scenarios outside of anticipated climate change scenarios.

4.1.6 Cost of Service and Opt-out Load

Under Oregon law, PGE must offer its cost-of-service (COS) rates to all customers.[66] COS rates are PGE's regulated, cost-based tariffs, as approved by the OPUC in PGE's general rate case and annual update tariff filings. The Company must offer to all non-residential customers the choice of leaving COS rates and electing either:[67]

- PGE’s daily or monthly index rates (i.e., variable price options or VPO); or
- A registered Electricity Services Supplier (ESS) as a supplier for one or five years.[68],[69]

Past experience suggests that some of the one-year (and previously three-year) opt-out customers may default back to PGE’s rates over time. These loads are included in PGE’s IRP planning. The Commission directed that the Company not plan for long-term resources to meet potential demand from five-year opt-out customers in IRP Guideline 9 of Order No. 07-002. When the OPUC adopted this guideline in 2007, long-term direct access participation was much smaller than the current participation. Long-term direct access participation is now close to 200 MW. Figure 4-2 shows a detailed, historic break-out of non-COS customers by year and by duration of election.

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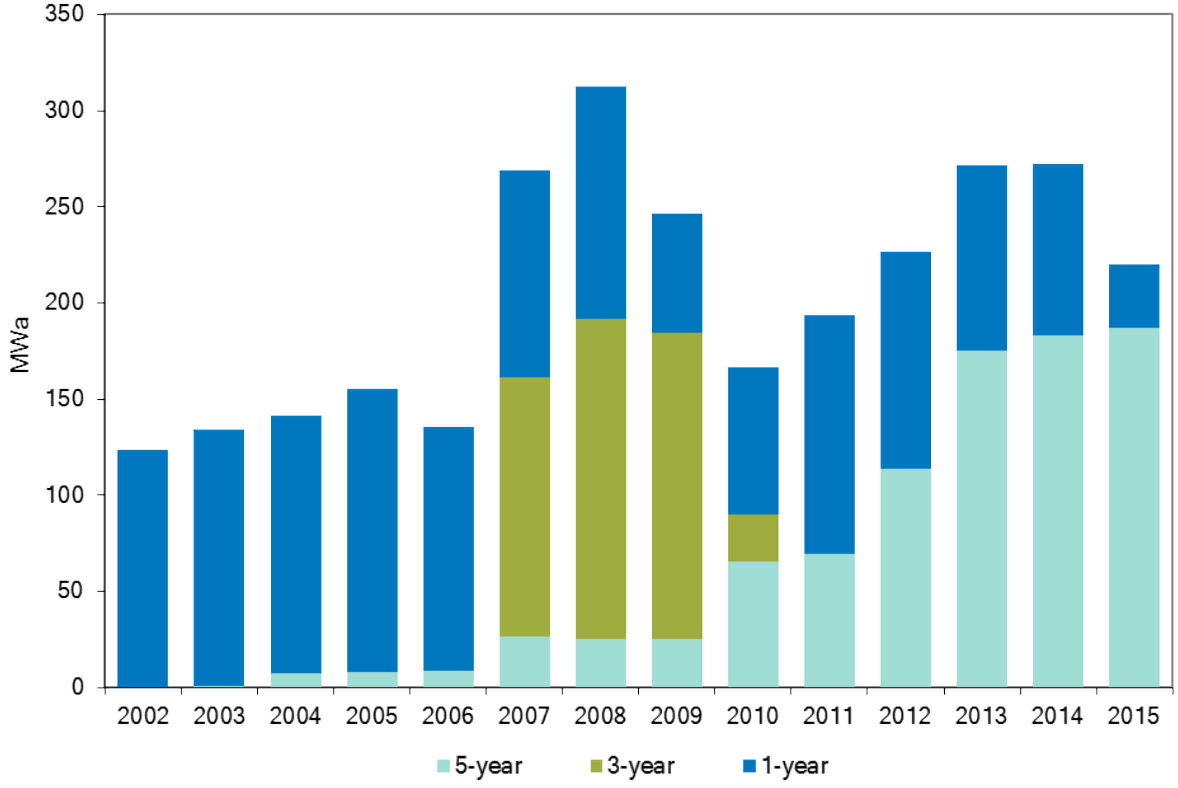
[66] See ORS 757.6031(a) and OAR 860-038-0240.

[67] See OAR 860-830-0275, Direct Access Annual Announcement and Election Period.

[68] A three-year opt-out option is also available; however, no customers are currently electing that option.

[69] Customer load eligible for the five-year ESS option is limited to an aggregate cap of 300 MWa of PGE’s electric tariff. See Schedule 485, Large Non-Residential Cost of Service Opt-out (201-4,000kW), PGE Tariff PUC Oregon No. E-18, Fifth Revision of Sheet No. 485-1; see also Schedule 489, Large Non-Residential Cost of Service Opt-out (201-4,000kW), PGE Tariff PUC Oregon No. E-18, Fifth Revision of Sheet No. 485-1.

FIGURE 4-2: Non cost-of-service customer load by duration of election



Five-year opt-out customers must complete the five-year opt-out election before becoming eligible to elect COS rates and must provide a two-year notice to PGE before returning. While Guideline 9 does not allow long-term opt-out load in IRP planning, according to Oregon law and related OPUC rules, PGE remains responsible for providing default emergency service (i.e., serving as provider of last resort) for all jurisdictional customers, including long-term direct access customers in its system.[70]

Currently, PGE would address this risk by attempting to procure the emergency capacity needs through the short-term market. Should these direct access customers return to PGE with little notice, and PGE not be able to procure emergency capacity, curtailment could ensue, and PGE would be required to curtail cost of service customers on the same basis as five-year opt-out customers. This issue, and whether PGE should plan for that emergency capacity obligation, requires study. PGE intends to engage in further discussions with Commission Staff and stakeholders on these issues.

4.2 Plug-in Electric Vehicles

From 2011 to early 2016, cumulative U.S. plug-in electric vehicle (PEV) sales exceeded 400,000[71] vehicles. In Oregon, PGE estimates that number to be close to 9,000 vehicles.[72] PEVs include:

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[70] See ORS 757.622 and OAR 860-038-028; see also Rule G (1)(B), "Direct Access Service and Billing," PGE Tariff PUC Oregon No. E-18, First Revision of Sheet No. G-1.

[71] Insideevs.com monthly scorecard.

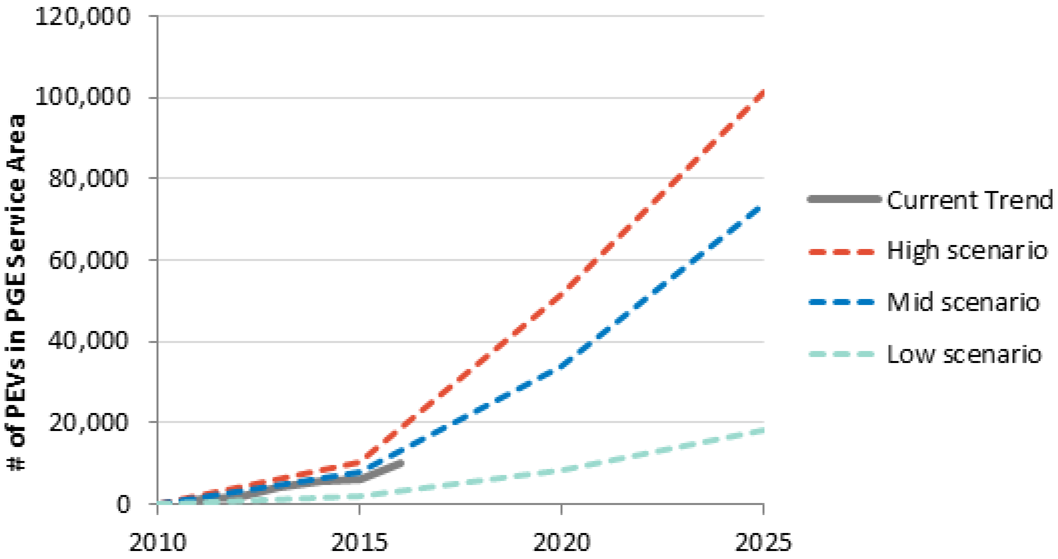
[72] Data from 12/31/2015. The Oregon Department of Transportation (ODOT) infrequently references Oregon numbers. However, PGE is working with Portland State University to get more accurate numbers with quarterly or semi-annual updates.

- **Battery electric vehicles** (BEV) that run entirely on a battery and do not use any fossil fuel;
- **Plug-in hybrid vehicles** (PHEV) that have an all-electric range before relying on fossil fuel; and
- **Extended range electric vehicles** (EREV) that run on electricity for a certain time before switching to an onboard generator to provide electricity for running the vehicle.

Early EV charging infrastructure development—spurred in part by the federally-funded EV Project and the West Coast Electric Highway Project—helped facilitate early PEV adoption in Oregon. PGE's support of both of these initiatives has also encouraged the early adoption of PEVs by Oregonians. Analysts anticipate that future availability of longer range and lower cost vehicles will further accelerate adoption.

In the 2013 IRP, PGE relied on Edison Electric Institute (EEI) forecasts for US PEV sales to approximate PGE service territory sales. Figure 4-3 reviews the performance of this estimate, showing the current trajectory of sales in PGE's Service territory compared to the previously developed scenarios.

FIGURE 4-3: Projected number of EVs in PGE's service area based on EEI scenarios

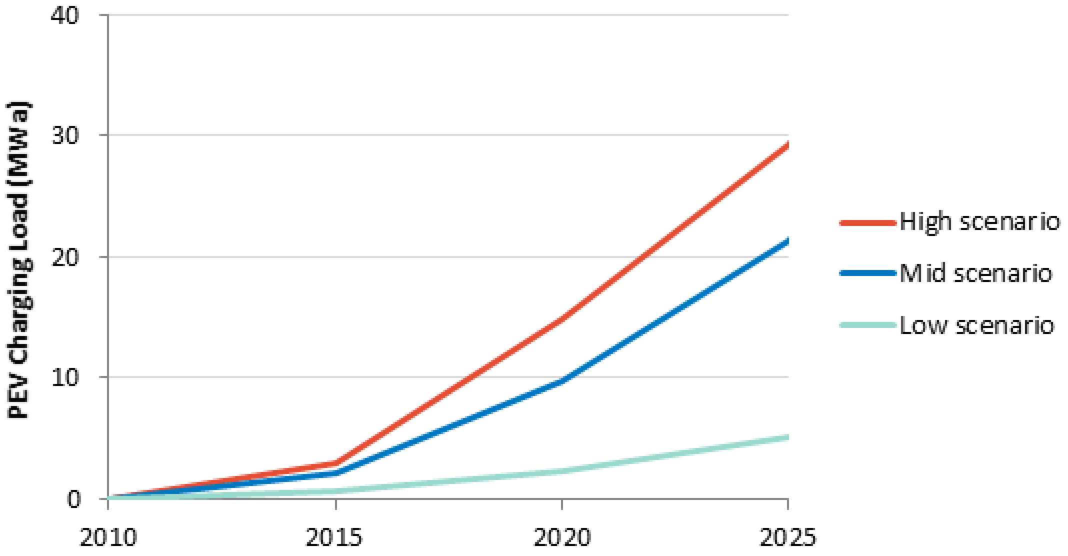


Currently, the actual number of vehicles in the PGE service area is tracking slightly below the medium scenario (see Figure 4-3). PGE believes the three scenarios developed for the 2013 IRP still represent a reasonable range on future PEV adoption through the IRP Action Plan window. Nonetheless, there are a number of events or activities that could influence these trends, including:

- **Technology costs.** More rapid reductions in the costs of electric vehicles due to manufacturing innovations and scale may drive additional adoption.
- **Gasoline prices.** High prices could drive adoption more towards the high scenario, while lower prices could slow adoption.
- **Tax credits.** Higher personal tax credits for electric vehicles or home charging infrastructure would likely increase adoption while lowering these credits is likely to reduce adoption.
- **Public charging infrastructure reliability.** A more expansive and more reliable public charging infrastructure may encourage increased adoption, while a low number of poorly maintained charging sites may negatively impact adoption.
- **Utility Transportation Electrification plans.** PGE will provide further information about its Transportation Electrification efforts once the OPUC finalizes proposed rules currently under development in Docket AR 599. The OPUC opened this docket in response to Section 29 of SB 1547, requiring Oregon utilities to submit Transportation Electrification program proposals by December 2016.

Figure 4-4 shows the forecasted load associated with the PEV adoption above-described scenario, based on EEI scenarios.

FIGURE 4-4: Projected PEV load in PGE's service area



The projected PEV load levels are relatively modest compared to the range of load growth scenarios described in Section 4.1.5, Load Growth Scenarios. PGE recognizes the potential for PEV adoption rates to exceed the EEI forecasts in future years. With this technology potential in mind, PGE is currently engaged in developing a more comprehensive PEV strategy through OPUC Docket AR 599.

4.3 Required Reserves

As a member of the Northwest Power Pool Reserve Sharing Group, PGE is required to carry reserves equal to three percent of its load and three percent of its generation to comply with Western Electricity Coordinating Council (WECC) Standard BAL-002-WECC-2 (WECC BAL-002).[73] The Federal Energy Regulatory Commission (FERC) approved WECC BAL-002 on November 21, 2013, and it became an enforceable requirement in October 2014.

The reserves required by WECC BAL-002 serve to provide upward capacity to stabilize the regional electricity grid during events such as when a generator trips offline. Operating Reserves – Spinning ("spinning reserves") must supply a minimum of half of the reserves, while Operating Reserves – Supplemental ("non-spinning reserves") may meet the remainder. Resource providing either type of operating reserve must be able to reach their assigned reserve capacity within ten minutes or less. If deployed for an event, a balancing authority must replace its reserve requirements within 60 minutes from the start of an event.

Spinning reserves must be "immediately and automatically responsive to frequency deviations through the action of a governor or other control system immediate and automatic responses to signals."[74] Generators synchronized to the grid—but not fully loaded—commonly provide spinning reserves. By contrast, non-spinning reserves may be offline, if they are capable of responding within the ten minute window. Dispatchable standby generators (DSG) (discussed in Chapter 7, Supply Options) are a key resource for meeting PGE's non-spin requirements.

The operating reserves required by WECC BAL-002 are part of PGE's capacity adequacy assessment discussed in Chapter 5, Resource Adequacy. PGE must also carry additional reserves with the ability to both increase and decrease generation (or serve as a load) in order to respond to load and generator changes across a variety of different time-steps. Section 5.3, Flexible Capacity, and Chapter 8, Energy Storage, discuss these flexibility-related considerations and the associated operating reserve requirements.

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[73] WECC Standard BAL-002-WECC-2 – Contingency Reserve.

[74] WECC Standard BAL-002-WECC-2 – Contingency Reserve, B.,R2.,2.1.

CHAPTER 5. Resource Adequacy

This chapter provides the results of studies to assess the ability of PGE's existing resources and future resource options to provide the capacity and flexibility needed to reliably serve the Company's future obligations for customer demand and operating reserves. The chapter describes the methodologies, assumptions, and findings of PGE's capacity adequacy study, an investigation into the capacity contribution of variable renewables, and a flexible capacity study. Additionally, the chapter includes a discussion of the regional reliability outlook, PGE's forecast Renewable Portfolio Standard (RPS) renewable energy credit (REC) obligations and production, and PGE's energy load-resource balance (LRB).

Chapter Highlights

- ★ **PGE updated its capacity need and capacity contribution assessments to a comprehensive methodology based on loss-of-load-probability (LOLP).**
- ★ **The company has an annual capacity need of approximately 819 MW in 2021. Seasonal resources may be suited to meet a portion of this need.**
- ★ **Capacity contributions from intermittent resources vary by technology, location, and load correlation. Capacity contribution generally declines as more of the same resource is added to the system.**
- ★ **PGE has a flexibility need of approximately 400 MW of dispatchable resources. PGE's flexibility needs will increase with increasing RPS levels.**

5.1 Capacity Adequacy and Capacity Contribution

5.1.1 Capacity Adequacy Overview

Over time, PGE projects that its loads will grow, existing contracts will expire, and there will be changes to the generating fleet, such as when Boardman ceases coal-fired operations at the end of 2020. In order to continue to maintain the ability to reliably serve load and supply required operating reserves, PGE must obtain additional capacity resources.

The Company completed a capacity adequacy study for this IRP to determine the capacity needed in each year of the planning horizon to maintain the targeted reliability level. The study assessed the need for traditional capacity from a long-term planning perspective. It did not examine flexible capacity issues related to subhourly variability, forecast errors, regulation reserves, or flexibility constraints on conventional technologies. These considerations are addressed in the flexible capacity study discussed in Section 5.3, Flexible Capacity.[75]

Figure 5-1 provides a summary of the annual capacity need.[76] The Company has a relatively small capacity deficit in the initial years, increasing to an 819 MW deficit in 2021 when Boardman ceases coal-fired operations. Due to load growth and contract expirations, the deficit continues to grow, reaching 1,864 MW in 2035, when PGE removes Colstrip Units 3 and 4 from its resource stack.[77] The following sections describe the capacity adequacy model and inputs used for this assessment. Appendix P, Load Resource Balance Tables, provides this information in tabular format.

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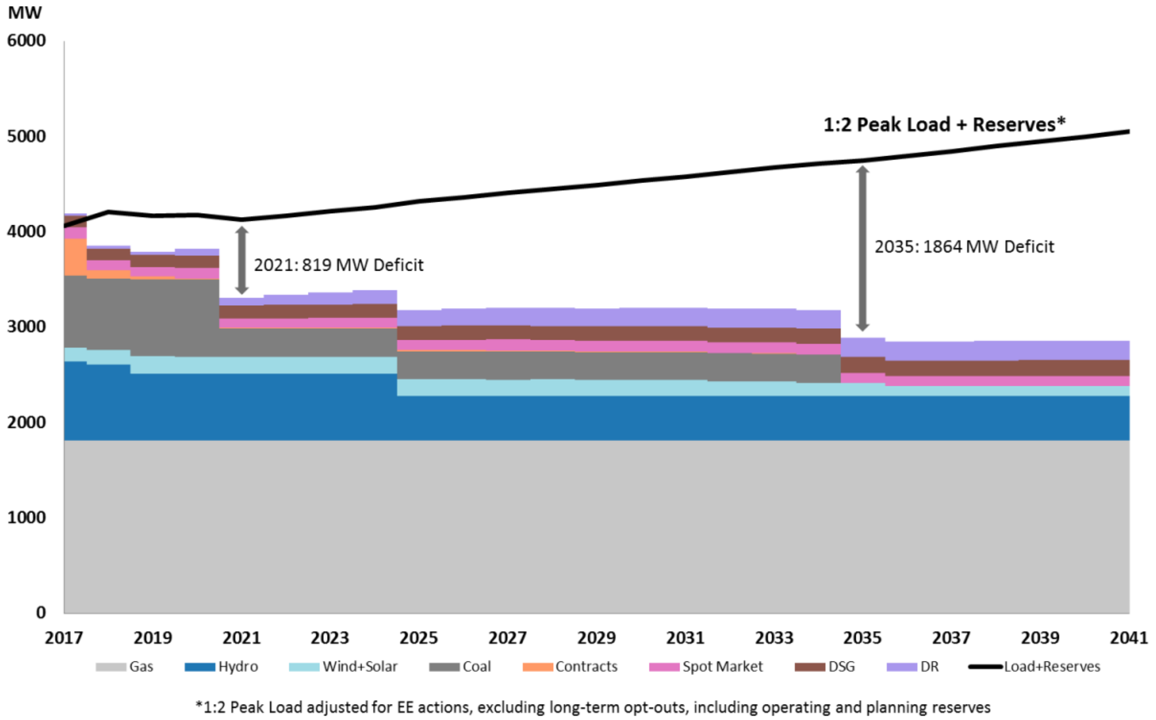
[75] Additionally, PGE's decision to join the Western EIM did not impact this study. As an EIM participant, PGE will need to show resource sufficiency for each hour (CAISO Tariff, § 29.34 EIM Operations).

[76] Figure 5-1 depicts the capacity need after incremental actions for energy efficiency (EE), demand response (DR), and dispatchable standby generation (DSG). The need is also incremental to the spot market assumptions.

[77] Per SB 1547, Colstrip Units 3 and 4 are removed from the resource stack prior to January 1, 2035. SB 1547 is discussed in Chapter 3, Planning Environment.

FIGURE 5-1: PGE's estimated annual capacity need



5.1.2 Status of Methodology from 2013 IRP

In the 2013 IRP, PGE assessed separate winter and summer seasonal capacity needs based on forecast one-in-two seasonal peak loads plus additional reserves. The Company planned for approximately 12 percent reserves composed of:

- Six percent operating reserves (spinning and non-spinning reserves) as required by the Western Electricity Coordinating Council (WECC); and
- Six percent reserve margin for load excursions due to extreme weather events and unplanned generator and transmission outages that extend beyond the time to be covered by operating reserves.

During the development process for the 2016 IRP, the Company determined that it needed a loss-of-load assessment to re-benchmark the capacity need, given the changes to the resource stack. PGE also concluded that its process would be improved by developing a single comprehensive and internally consistent loss-of-load model for assessing capacity need, determining renewable capacity contribution, and evaluating portfolio reliability. In addition, the Company sought to improve the resource evaluation process and address stakeholder concerns raised in the 2013 IRP process by developing capacity contribution calculations with the ability to capture impacts of technology, load correlation, portfolio benefits, and declining marginal value.

Updating the modeling methodology to a loss-of-load probability (LOLP) model involved a substantial amount of complexity, preparation time, and computing time compared to the previous heuristic method. In order to accomplish the update under a short timeline, PGE engaged Energy and Environmental Economics, Inc. (E3) to complete a study of capacity need and capacity contribution using E3's publicly available Renewable Energy Capacity Planning model (RECAP). E3 was able to leverage work already begun to model PGE's system for the flexible capacity study described in Section 5.3, Flexible Capacity, in order to develop a detailed RECAP analysis for the PGE system. During the study's development, PGE made several presentations to stakeholders at public meetings, including an initial overview presented by E3 at the August 13, 2015 public meeting. PGE received positive feedback from participants at the meetings.

In April 2016, PGE received a copy of the final model from E3. Over the next three months, the Company expanded the model to enable simulations for all years in the IRP horizon (2017-2050) and updated input data to capture a more current snapshot of PGE's resources.[78] PGE presented the updated results at its August 17, 2016 public meeting. The following sections summarize the model inputs and study results.

5.1.3 RECAP Model Inputs

RECAP is a comprehensive LOLP-based model built in Python code with an Excel interface and is available for download from E3's website. The model calculates the LOLP for each month/day-type/hour[79] of a test year. Additionally, RECAP calculates the capacity needed to achieve a desired reliability target, the capacity contribution values for existing variable resources, and the marginal capacity contributions for incremental resources. The model also captures correlations between load and variable resource generation. In order to understand the study results, it is important to understand the inputs to the model.

Reliability Target

RECAP requires an annual reliability target and definition of adequacy. PGE defined adequacy as sufficient resources to meet the hourly load plus required operating reserves (spinning and non-spinning).[80] The reliability target selected was a loss of load expectation (LOLE) of 1-day-in-10 years, or 2.4 hours per year. This is a common industry target and results in a total reserve margin (operating and planning) of approximately 17 percent for 2021.

It is important to note that the total reserve margin percentage is not a direct output of the model. The model produces a capacity shortage value in MW. In this study, the shortage is expressed as MW of conventional units needed to achieve the reliability target. The conventional units are defined as 100 MW units with five percent forced outage rates (FOR). For each year, a total reserve margin is calculated by the following:

$$\text{Total Reserve Margin} = \frac{[\text{Existing Resources} + \text{Capacity Shortage}] - [\text{1:2 Peak Load}]}{[\text{1:2 Peak Load}]}$$

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[78] Updates included contracts executed as of May 31, 2016 and the reference demand response forecast. A description of the updates was included in the August 17, 2016 Public Meeting.

[79] "Day-type" refers to whether the day is a weekday or a weekend.

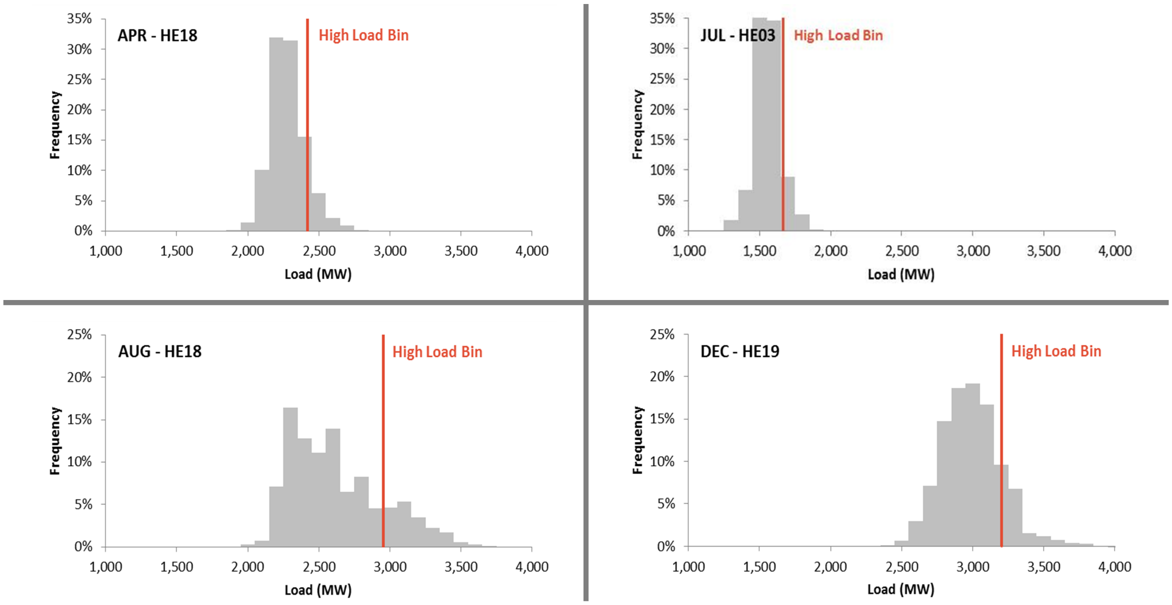
[80] Operating reserve requirements based on WECC BAL-002 spinning and supplemental (non-spin) reserves (approximated as 6% of load).

Load

E3 used extensive load and weather data to capture load behavior under a wide variety of weather conditions. Load shapes were created from recent history (2007-2014), as well as from weather data from 1980-2006 that was "trained" to recent history using a neural network. The load shapes were then scaled to PGE's load forecast.[81]

An example of four PGE load distributions for weekdays in 2021 are provided in Figure 5-2. RECAP creates load "bins" for each month/day-type/hour of the test year. The bins ensure that RECAP accounts for differences in wind and solar distributions across distinct load regimes. For example, wind and solar availability may follow a different distribution under high load conditions than under low load conditions.

FIGURE 5-2: PGE weekday load distributions for 2021



Wind and Solar

In order to capture the variability of wind and solar, the model uses hourly generation profiles from either historic actuals or synthetic generation calculated from historic wind and irradiance data. In order to capture correlations with load, the generation profiles need to be time-synchronous with load data. PGE modeled synthetic wind generation profiles using the National Renewable energy Laboratory's (NREL) five-minute wind data for 2004-2006 for Biglow Canyon, Tucannon River, contract wind, and candidate resource locations. These were included in RECAP along with historic Biglow Canyon generation data from 2008-2014. PGE modeled solar generation profiles based on NREL irradiance data for 2006 and University of Oregon irradiance data for 2003-2014.

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[81] The RECAP study used PGE's June 2015 load forecast, including energy efficiency (EE) actions, excluding long-term opt-out load. See Chapter 4, Resource Need.

PGE's wind and solar resources include owned, leased, and contracted resources. While wind resources dominate PGE's renewable portfolio, contracts for solar resources yet to come online have recently exceeded 200 MW.[82] Resource descriptions are provided in Appendix D, Existing Resources.

Hydro

The Clackamas, Pelton, and Round Butte projects were modeled with the same monthly sustained maximum capacity values used in the 2013 IRP.[83] For the Company's Mid-C resources, E3 built monthly probability distributions using PGE's monthly dependable capacities, historic hydro conditions, and Northwest Power and Conservation Council (NWPCC or the Council) data relating hydro conditions to peaking capability. Small, run-of river projects and contracts were included with either their monthly average energy or no capacity value on a case-by-case basis.[84] Appendix D, Existing Resources, describes PGE's hydro resources.

Thermal

RECAP represented each thermal resource by its monthly capacity associated with monthly average temperatures and its forced outage rate (FOR).[85] RECAP calculated probability distributions for the availability of each plant for each month using a generic industry FOR shape to allocate between partial and full outages. Appendix D, Existing Resources, provides a description of PGE's thermal resources.

Additional Items

RECAP also captured the following resources and requirements:

- Dispatchable Standby Generation (DSG) resources adjusted for availability based on the existing fleet plus the targeted annual acquisitions based on an E3 study of standby (non-spin) capacity needs discussed in Appendix G, Dispatchable Standby Generation Study.
- Demand Response (DR) based on the targeted acquisitions described in Chapter 6, Demand Options.
- Contracts executed as of May 31, 2016. See Appendix D, Existing Resources.
- Spot Market based on the 2013 IRP Loss-of-Load study levels (200 MW in non-summer hours), extended to include summer off-peak hours.
- Cost-effective EE actions based on ETO's June 2015 forecast. The EE actions are included in RECAP through the load forecast. The EE forecast is discussed in Chapter 6, Demand Options.

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[82] AC rating.

[83] Due to limited time, the Company did not reexamine the values in this IRP. In a future IRP cycle, PGE plans to evaluate the plant capabilities under current licensing and habitat requirements.

[84] As in the 2013 IRP, in order to simplify the modeling of a few small hydro resources, projects with outputs that are highly variable (such as Lake Oswego Hydro, approx. 0.03 MWa) were not attributed a capacity value while other small hydro resources with less variability were modeled based on their monthly average generation.

[85] Maintenance outages were not included because PGE can typically schedule planned maintenance in advance, with adequate time to secure short-term resources.

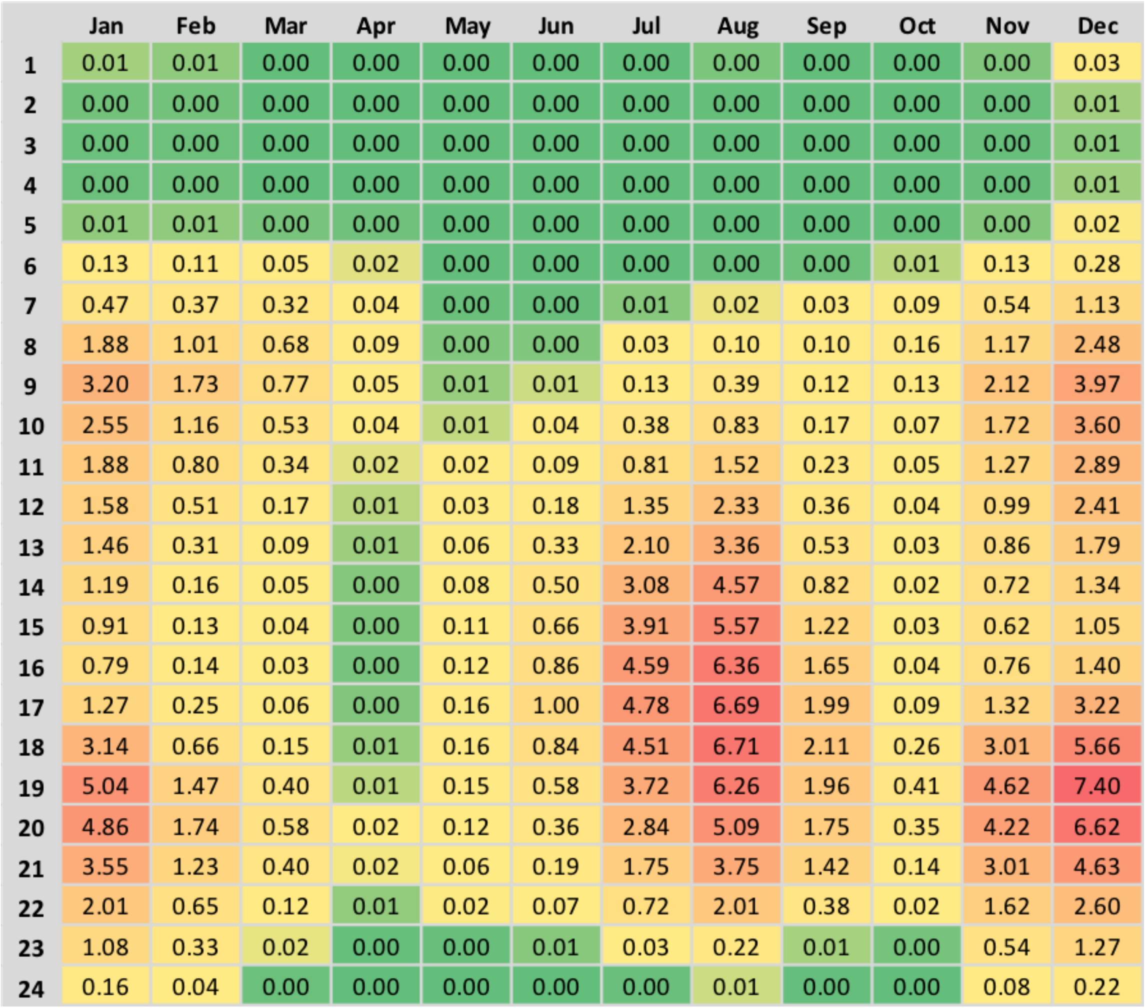
- Operating reserve requirements based on WECC BAL-002 spinning and supplemental (non-spin) reserves (approximated as six percent of load).

5.1.4 Loss of Load Expectation and Capacity Need

Using all of the resource input data, RECAP created a resource probability distribution curve for each month/day-type/hour. For variable resources, distinct distributions were also generated by load level within each month/day-type/hour. The model then combined the load and resource distributions via the convolution method to create a distribution representing the probability that the load plus reserves exceeded the available resources (variable, hydro, thermal, demand side, contracts, and spot market) in the month/day-type/hour.

For 2021, the RECAP study estimated that PGE's 2021 loss of load expectation (LOLE) is 253 hours per year (after EE, DR, and DSG acquisitions) if no additional resources are acquired. The heat map in Figure 5-3 shows the seasonal and hourly shape of the LOLE. The values indicate the LOLE for the month/hour with shading from green to red indicating lowest to highest LOLE. While PGE has some LOLE across most on-peak hours, the greatest needs are in the winter morning and evening hours and in the summer afternoon and evening hours.

FIGURE 5-3: PGE's LOLE (hours per year) in 2021 before capacity actions



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
5	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
6	0.13	0.11	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.28
7	0.47	0.37	0.32	0.04	0.00	0.00	0.01	0.02	0.03	0.09	0.54	1.13
8	1.88	1.01	0.68	0.09	0.00	0.00	0.03	0.10	0.10	0.16	1.17	2.48
9	3.20	1.73	0.77	0.05	0.01	0.01	0.13	0.39	0.12	0.13	2.12	3.97
10	2.55	1.16	0.53	0.04	0.01	0.04	0.38	0.83	0.17	0.07	1.72	3.60
11	1.88	0.80	0.34	0.02	0.02	0.09	0.81	1.52	0.23	0.05	1.27	2.89
12	1.58	0.51	0.17	0.01	0.03	0.18	1.35	2.33	0.36	0.04	0.99	2.41
13	1.46	0.31	0.09	0.01	0.06	0.33	2.10	3.36	0.53	0.03	0.86	1.79
14	1.19	0.16	0.05	0.00	0.08	0.50	3.08	4.57	0.82	0.02	0.72	1.34
15	0.91	0.13	0.04	0.00	0.11	0.66	3.91	5.57	1.22	0.03	0.62	1.05
16	0.79	0.14	0.03	0.00	0.12	0.86	4.59	6.36	1.65	0.04	0.76	1.40
17	1.27	0.25	0.06	0.00	0.16	1.00	4.78	6.69	1.99	0.09	1.32	3.22
18	3.14	0.66	0.15	0.01	0.16	0.84	4.51	6.71	2.11	0.26	3.01	5.66
19	5.04	1.47	0.40	0.01	0.15	0.58	3.72	6.26	1.96	0.41	4.62	7.40
20	4.86	1.74	0.58	0.02	0.12	0.36	2.84	5.09	1.75	0.35	4.22	6.62
21	3.55	1.23	0.40	0.02	0.06	0.19	1.75	3.75	1.42	0.14	3.01	4.63
22	2.01	0.65	0.12	0.01	0.02	0.07	0.72	2.01	0.38	0.02	1.62	2.60
23	1.08	0.33	0.02	0.00	0.00	0.01	0.03	0.22	0.01	0.00	0.54	1.27
24	0.16	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.08	0.22

In order to determine the annual capacity needed to achieve the resource adequacy target, RECAP iterated adding conventional units (CUs),[86] until the model reduced the LOLE to 2.4 hours per year.[87] For 2021, RECAP added 819 MW to achieve the target. The quantity needed in each year is the identified annual capacity need. Figure 5-4 shows the capacity need identified for 2017-2041.[88] This is the same need reflected in Figure 5-1.

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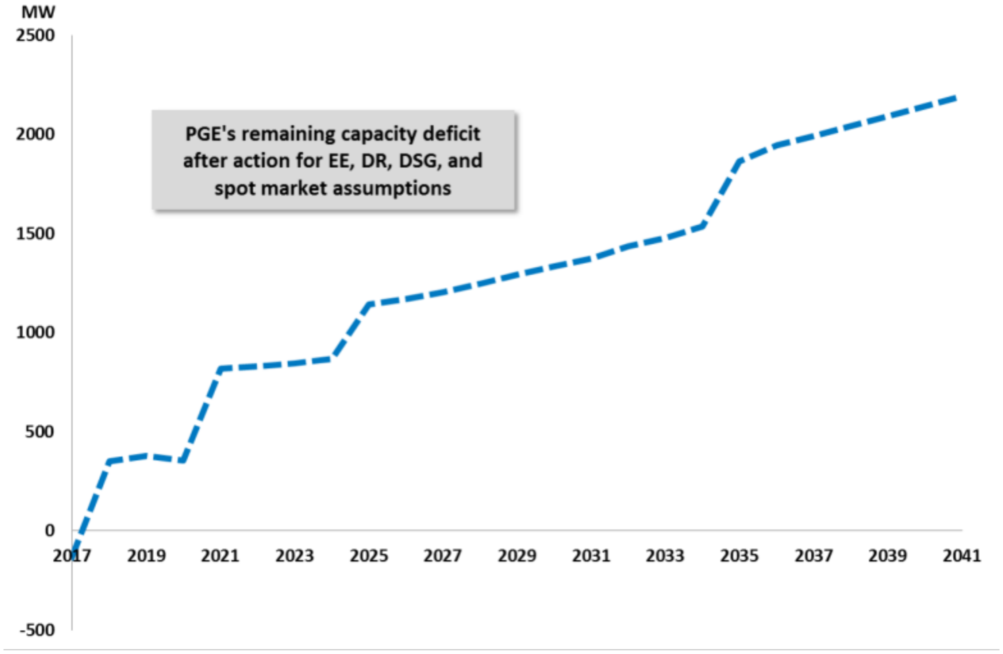
[86] As mentioned above, a CU is a 100 MW unit with a five percent FOR.

[87] RECAP does add partial conventional units to achieve the target.

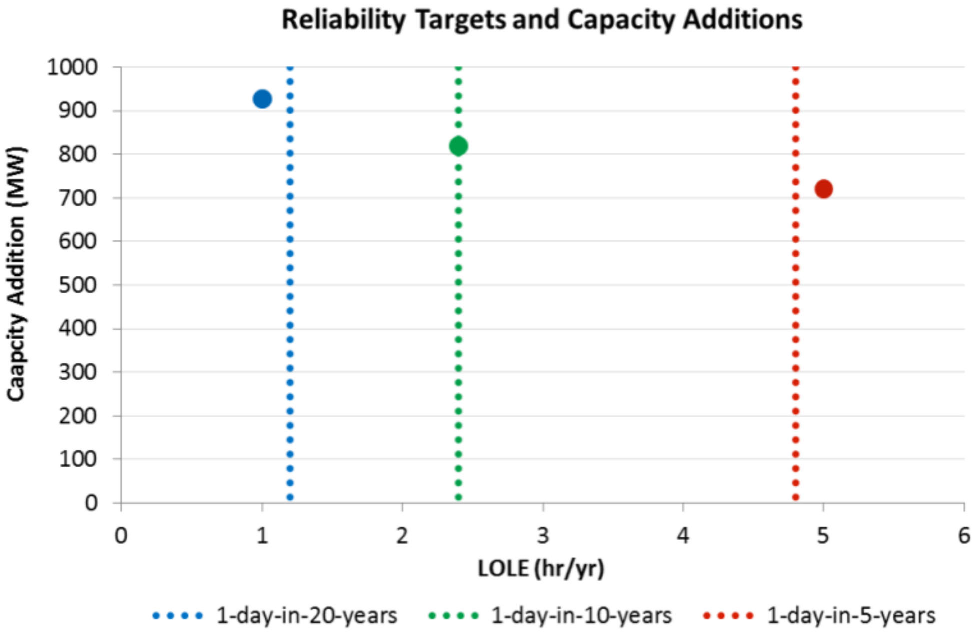
[88] As discussed previously, this is the identified need incremental to the actions for EE, DR, and DSG. It is also incremental to the spot market assumptions.

FIGURE 5-4: PGE annual capacity need



PGE examined the impact on achieving the targeted 1-day-in-10-year LOLE metric in 2021 if the capacity addition is varied by approximately ±100 MW and found a substantial change to the reliability level. As seen in Figure 5-5, adding 721 MW does not achieve a target of 1-day-in-5 years while adding 928 MW is above a target of 1-day-in-20-years. This sensitivity, along with the context of a capacity need that continues to grow after 2021, helps to inform PGE's recommendations in Chapter 13, Action Plan.

FIGURE 5-5: 2021 capacity additions and LOLE

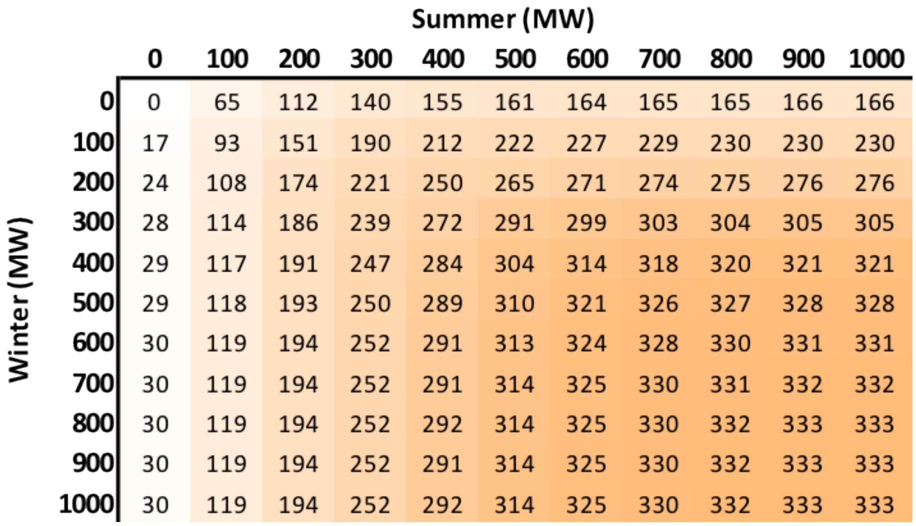


5.1.4.1 Seasonal Capacity Products

A portion of PGE's capacity need may be met with seasonal capacity products.[89] The optimal blend of seasonal and annual products will depend on multiple factors, including resource fixed and variable costs, dispatch characteristics, and capacity contribution values. Seasonal product characteristics vary widely and future availability and costs are challenging to forecast. This IRP does not attempt to include seasonal products in portfolio analysis, but PGE estimated the capacity contributions for an example set of products and explored the economics of seasonal versus annual products at a high level in the analysis described below.

PGE used RECAP to examine the capacity contribution of example seasonal products available in the on-peak hours of July through September (summer) and December through February (winter). The modeling for the seasonal cases used a base portfolio that included an RPS resource of 175 MWa of Pacific Northwest Gorge Wind (PNW Wind) in addition to the EE, DR, and DSG actions. The remaining annual capacity need above the base portfolio was 760 MW. The modeling examined adding a range of seasonal and annual products to fill the 760 MW need. Figure 5-6 shows the capacity contribution of the seasonal products expressed as an effective load carrying contribution (ELCC) value (the amount of annual conventional units avoided). Figure 5-7 shows the remaining annual need under the range of combinations of seasonal products. For example, if PGE adds 500 MW of summer product and 400 MW of winter product, the combined ELCC is 304 MW and the remaining annual need is 456 MW. The figures indicate a steep decline to the marginal value of the seasonal products and that seasonal products alone are unlikely to achieve resource adequacy.

FIGURE 5-6: Example seasonal product portfolio ELCCs (MW)



	Summer (MW)										
Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	0	65	112	140	155	161	164	165	165	166	166
100	17	93	151	190	212	222	227	229	230	230	230
200	24	108	174	221	250	265	271	274	275	276	276
300	28	114	186	239	272	291	299	303	304	305	305
400	29	117	191	247	284	304	314	318	320	321	321
500	29	118	193	250	289	310	321	326	327	328	328
600	30	119	194	252	291	313	324	328	330	331	331
700	30	119	194	252	291	314	325	330	331	332	332
800	30	119	194	252	292	314	325	330	332	333	333
900	30	119	194	252	291	314	325	330	332	333	333
1000	30	119	194	252	292	314	325	330	332	333	333

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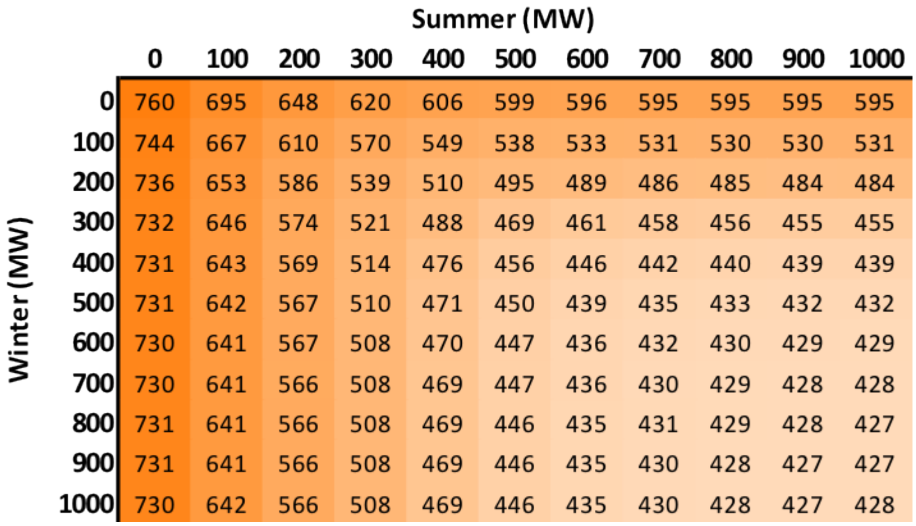
[89] For this IRP, a seasonal capacity product is a capacity contract or resource for defined months (typically July-September or December-February), often with limited hours of availability.

FIGURE 5-7: Example remaining annual need (MW) with seasonal product portfolios



	Summer (MW)										
Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	760	695	648	620	606	599	596	595	595	595	595
100	744	667	610	570	549	538	533	531	530	530	531
200	736	653	586	539	510	495	489	486	485	484	484
300	732	646	574	521	488	469	461	458	456	455	455
400	731	643	569	514	476	456	446	442	440	439	439
500	731	642	567	510	471	450	439	435	433	432	432
600	730	641	567	508	470	447	436	432	430	429	429
700	730	641	566	508	469	447	436	430	429	428	428
800	731	641	566	508	469	446	435	431	429	428	427
900	731	641	566	508	469	446	435	430	428	427	427
1000	730	642	566	508	469	446	435	430	428	427	428

In order to examine the impact of the ELCC values on the least-cost combination of annual and seasonal products, PGE prepared a simplified calculation for the same set of seasonal products under four price scenarios. PGE made the following assumptions in the scenarios for simplification:

- The average cost of an annual capacity resource was approximated as \$100/kW-yr.[90]
- The four price scenarios examined different relationships between the monthly price per kW of the seasonal and annual products: 25 percent, 50 percent, 100 percent, and 200 percent. For example, in the 25 percent scenario, the monthly seasonal product price per kW is 25 percent of the monthly price per kW of the annual product, so the annual product costs [\$100/kW-yr]/[12 months] = \$8.33/kW-month in each month of the year and the seasonal product costs [25% x \$8.33/kW-month] = \$2.08/kW-month in each of the months in which it is available.
- Variable costs and potential operational benefits of capacity resources were neglected.

Figure 5-8 shows the average cost of capacity (in \$/kW-yr) in the four price scenarios given various combinations of summer, winter, and annual capacity products. In each chart, the green area indicates the least expensive combinations of summer, winter, and annual resources for the price scenario. For example, in the 50 percent scenario, the lowest cost portfolio is comprised of 500 MW summer, 400 MW winter, and 456 MW of annual resources (per remaining annual need in Figure 5-7), resulting in an average cost of capacity of \$75/kW-yr.

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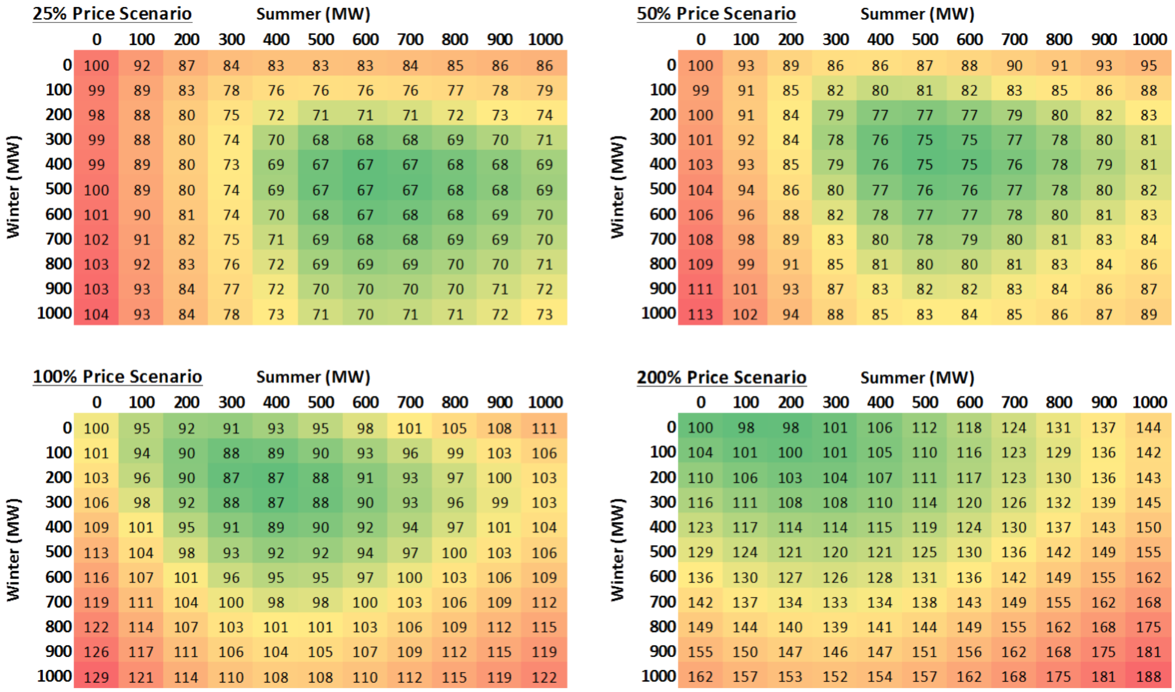
[90] This proxy cost was used only for the sake of simplification in the exploration of the relative costs and benefits of annual versus seasonal products. It was not used elsewhere in the IRP.

FIGURE 5-8: Annual/seasonal fixed cost ($/kW-yr) across price scenarios



25% Price Scenario Summer (MW)

Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	100	92	87	84	83	83	83	84	85	86	86
100	99	89	83	78	76	76	76	76	77	78	79
200	98	88	80	75	72	71	71	71	72	73	74
300	99	88	80	74	70	68	68	68	69	70	71
400	99	89	80	73	69	67	67	67	68	68	69
500	100	89	80	74	69	67	67	67	68	68	69
600	101	90	81	74	70	68	67	68	68	69	70
700	102	91	82	75	71	69	68	68	69	69	70
800	103	92	83	76	72	69	69	69	70	70	71
900	103	93	84	77	72	70	70	70	70	71	72
1000	104	93	84	78	73	71	70	71	71	72	73

50% Price Scenario Summer (MW)

Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	100	93	89	86	86	87	88	90	91	93	95
100	99	91	85	82	80	81	82	83	85	86	88
200	100	91	84	79	77	77	77	79	80	82	83
300	101	92	84	78	76	75	75	77	78	80	81
400	103	93	85	79	76	75	75	76	78	79	81
500	104	94	86	80	77	76	76	77	78	80	82
600	106	96	88	82	78	77	77	78	80	81	83
700	108	98	89	83	80	78	79	80	81	83	84
800	109	99	91	85	81	80	80	81	83	84	86
900	111	101	93	87	83	82	82	83	84	86	87
1000	113	102	94	88	85	83	84	85	86	87	89

100% Price Scenario Summer (MW)

Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	100	95	92	91	93	95	98	101	105	108	111
100	101	94	90	88	89	90	93	96	99	103	106
200	103	96	90	87	87	88	91	93	97	100	103
300	106	98	92	88	87	88	90	93	96	99	103
400	109	101	95	91	89	90	92	94	97	101	104
500	113	104	98	93	92	92	94	97	100	103	106
600	116	107	101	96	95	95	97	100	103	106	109
700	119	111	104	100	98	98	100	103	106	109	112
800	122	114	107	103	101	101	103	106	109	112	115
900	126	117	111	106	104	105	107	109	112	115	119
1000	129	121	114	110	108	108	110	112	115	119	122

200% Price Scenario Summer (MW)

Winter (MW)	0	100	200	300	400	500	600	700	800	900	1000
0	100	98	98	101	106	112	118	124	131	137	144
100	104	101	100	101	105	110	116	123	129	136	142
200	110	106	103	104	107	111	117	123	130	136	143
300	116	111	108	108	110	114	120	126	132	139	145
400	123	117	114	114	115	119	124	130	137	143	150
500	129	124	121	120	121	125	130	136	142	149	155
600	136	130	127	126	128	131	136	142	149	155	162
700	142	137	134	133	134	138	143	149	155	162	168
800	149	144	140	139	141	144	149	155	162	168	175
900	155	150	147	146	147	151	156	162	168	175	181
1000	162	157	153	152	154	157	162	168	175	181	188

These simplified scenarios indicate a blend of annual and seasonal products has the potential to achieve a reduced cost compared to annual products alone. Despite this insight, the optimal combination of seasonal and annual resources cannot be determined prior to evaluating actual bid information and, as mentioned before, the evaluation will include additional factors beyond capacity contributions and fixed costs. Additional discussions about seasonal and annual capacity are included in Chapter 13, Action Plan.

5.1.5 Capacity Contribution

The ELCC of an incremental resource is the incremental capacity contribution brought by the resource to a specific system given both the characteristics of the resource and the system (load profile and the composition of its existing resources). RECAP captures these characteristics, as described below.[91]

Forced Outage Rates and Unit Size. RECAP captures the impact of forced outage rates and unit size on ELCC values for resources such as thermal units. For example, a 200 MW combustion turbine with a three percent FOR has a lower ELCC than a similarly sized unit with a two percent FOR. Similarly, a resource consisting of one 400 MW unit will have a lower ELCC value than four 100 MW units with the same FOR due to the higher probability of a 400 MW outage for the single large unit than simultaneous outages across four 100 MW units.

Technology and Location. The generation profile of a variable energy resource (VER) depends on the technology and location. The technology (such as the wind turbine type or solar

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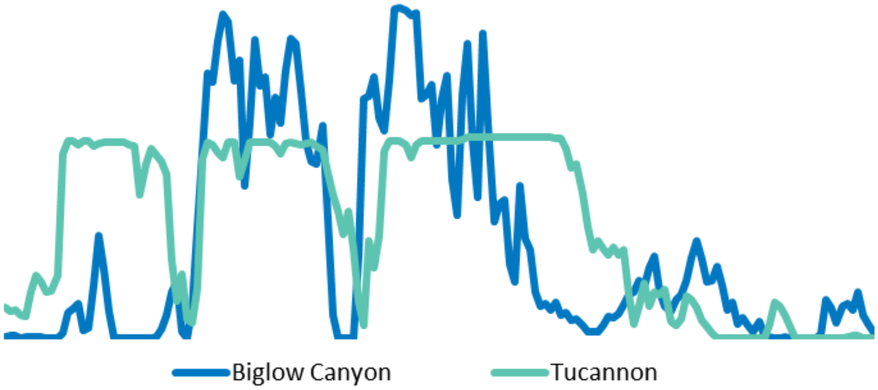
[91] This discussion does not capture system needs related to sub-hourly variability or forecast error. Those items are covered in the integration discussion in Section 5.3, Flexible Capacity.

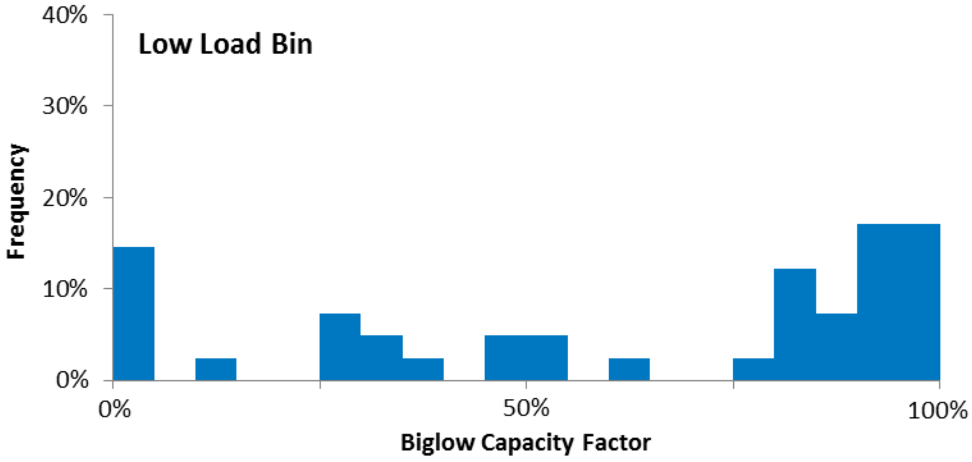
photovoltaic panel type) impacts the resource's ability to convert available fuel (wind, irradiance) to electricity. The resource location changes the profile of the availability of the fuel and the variability across multiple time frames (hourly, seasonally, annually). For highly variable resources, such as wind, multiple years of data improve the characterization of the resource. Figure 5-9 shows the short-term variability of seven consecutive days of output from Biglow Canyon and Tucannon River wind farms from December 2015.

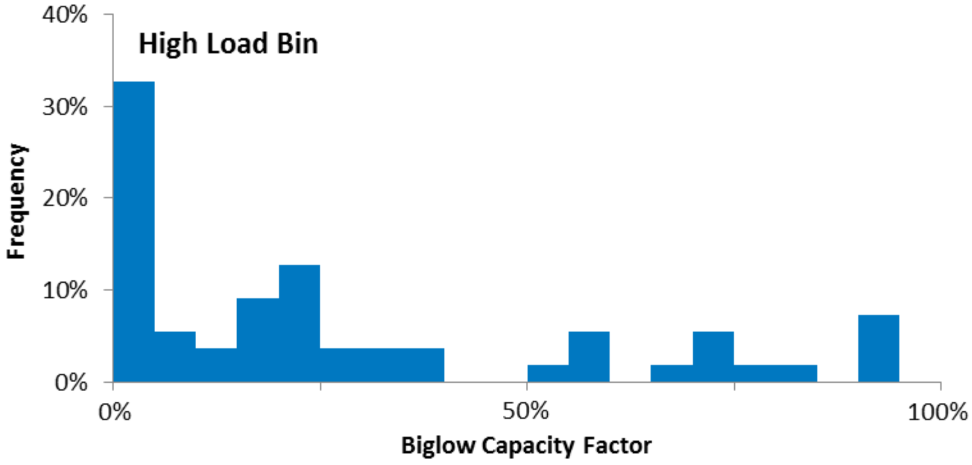
FIGURE 5-9: Biglow Canyon and Tucannon River generation, seven consecutive days in December 2015



Load Correlation. VER generation profiles included in RECAP are from historic data (either actual generation or synthetic generation based on historic wind and irradiance data) that is time-synchronous with load data. Using this information, RECAP captures positive or negative correlations with load. Load correlation provides a simplified method for capturing relationships with weather that can impact both load and generation. For example, solar irradiance tends to be high on clear sunny days when load may also be high due to increased air conditioning loads. The correlation between wind and load can vary substantially by region and by season with some areas experiencing periods of negative correlation. Figure 5-10 shows probability distributions for Biglow Canyon capacity factors on August weekdays, hour ending 6 p.m., separated by low and high load bins. These charts indicate that for this season, conditions leading to high loads tend to also be associated with lower capacity factors than conditions that result in lower loads.

FIGURE 5-10: Biglow Canyon capacity factor frequency by load bin, Aug, weekday, HE18





Portfolio Effects. Recall from the seasonable product analysis in Section 5.1.4, Loss of Load Expectation and Capacity Need, that the ELCC of two or more complementary resources can be larger than the sum of the separate ELCCs. For example, PGE found that adding 200 MW of summer and 200 MW of winter products has a combined ELCC of 174 MW. When considered separately, a 200 MW summer product has an ELCC of 112 MW and a 200 MW winter product has an ELCC of 24 MW (112 MW + 24 MW = 136 MW < 174 MW). RECAP captures this "portfolio effect" between complementary resources of all types, whether they be seasonal capacity products or variable renewables.

Declining Marginal Value. As RECAP adds more of the same type of VER or seasonal resource to a system, each additional unit added has incrementally less capacity value. The rate of decline varies depending on the resource and system profile. Figure 5-11 shows the marginal ELCCs for 100 MW incremental additions of PNW wind, Montana wind, and single-axis tracking solar.[92] For example, the

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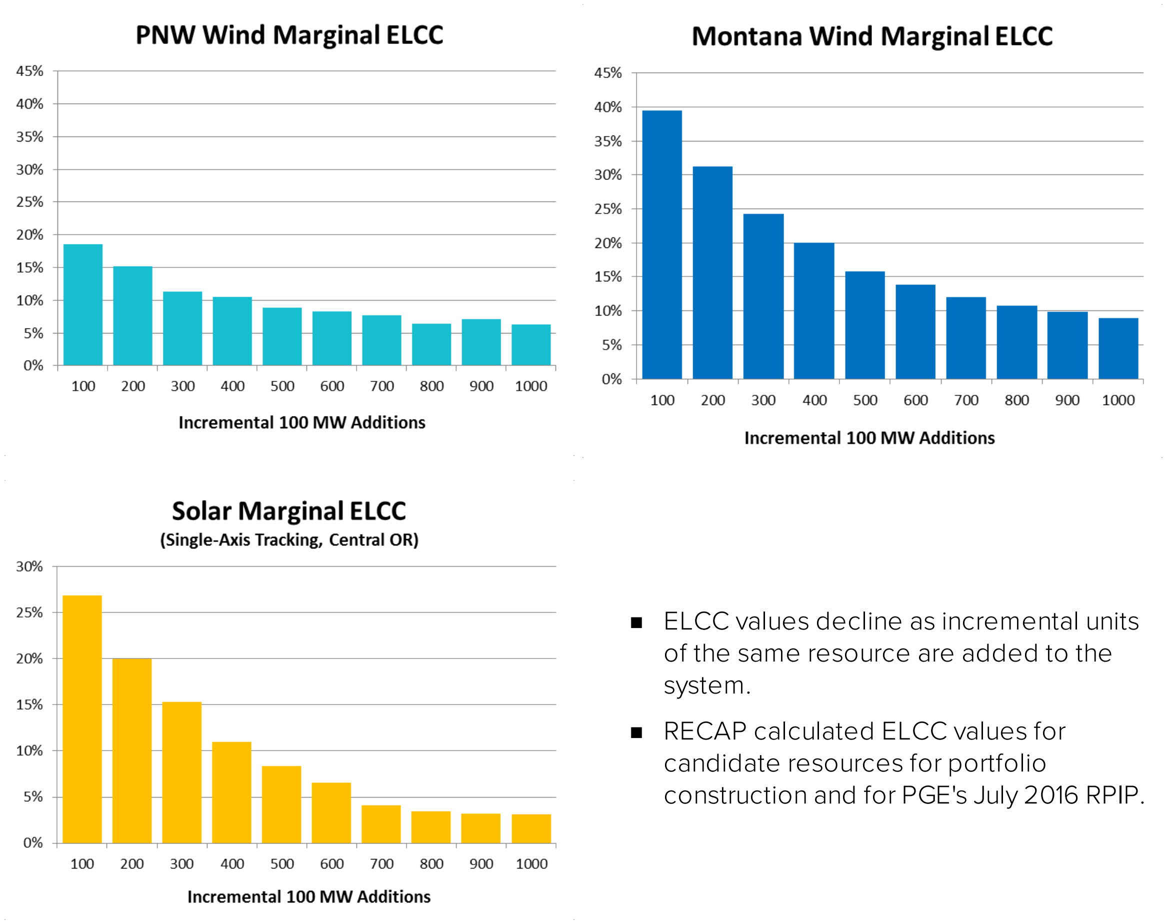
[92] These values are based on incremental additions to the existing system as discussed in Section 5.1.3, RECAP Model Inputs, and in Appendix D, Existing Resources.

marginal ELCC of the first 100 MW of Montana wind is approximately 39 percent and the ELCC of the next 100 MW (200 MW bin) is approximately 32 percent.

FIGURE 5-11: Marginal ELCC values for incremental 100 MW resource additions



- ELCC values decline as incremental units of the same resource are added to the system.
- RECAP calculated ELCC values for candidate resources for portfolio construction and for PGE's July 2016 RPIP.

5.1.5.1 UM 1719 – Renewable Capacity Contribution Investigation

On March 10, 2015, the OPUC opened docket UM 1719 to explore issues related to a renewable generator's contribution to capacity. This docket was opened in response to OPUC Order No. 14-415, Section IV(B) in PGE's 2013 IRP.

Parties participated in workshops, one round of opening testimony, and settlement conferences. On April 29, 2016, parties filed joint testimony supporting a stipulation on the methodologies for calculating capacity contributions for wind and solar resources in IRPs. The stipulation allows for the use of either an ELCC methodology or a capacity factor (CF) methodology with a waiver provision. The OPUC adopted the terms of the stipulation in Order No. 16-326, issued on August 26, 2016. The OPUC added an additional requirement that CF methodologies be benchmarked to ELCC calculations under higher levels of renewables.[93]

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[93] OPUC Order No. 16-326, Section IV(B).

While the requirements of the Order will apply to PGE's next IRP cycle, PGE notes that the methodology used in the 2016 IRP uses an ELCC methodology with calculations based on an assessment of a full year, consistent with the requirements of the Order.

5.1.6 Inclusion in IRP Analysis

The RECAP study was incorporated into several areas of PGE's IRP:

- **DSG Acquisitions.** PGE used RECAP to determine the targeted levels of incremental DSG resources to acquire to fill the standby capacity need. See Appendix G, Dispatchable Standby Generation Study.
- **Flexible Capacity.** The flexible capacity study required an assessment of the system's need for traditional capacity, which relied on analysis from RECAP. See Section 5.3, *Flexible Capacity*.
- **Portfolio Construction.** PGE used RECAP to evaluate the ELCC of resource additions (capturing impacts of forced outage rates, unit size, technology, load correlation, portfolio effects, and declining marginal value) and to determine the remaining "generic" capacity needed to achieve resource adequacy (excluding the portfolio with no capacity actions). See Chapter 10, Modeling Methodology.
- **Portfolio Evaluation.** PGE used RECAP to evaluate the LOLP, expected unserved energy (EUE), and the TailVar90 of unmet demand (i.e., the expected magnitude of shortage experienced in the top 10th percentile of loss of load events) - see Appendix O, Portfolio Detail.
- **Action Plan.** PGE used the RECAP results for capacity need and seasonal product performance to establish the quantities of the capacity actions in the Action Plan. See Chapter 13, Action Plan.

5.1.7 Modeling Considerations for the Future

For this IRP, PGE took significant steps to improve the modeling used for assessing capacity needs and capacity contributions. PGE intends to continue to build on this work to further improve its modeling in future IRP cycles. The Company is examining several items for update or review, include the following:

- **Improve resource input data sets.** The quality and quantity of input data used for modeling intermittent resources is a key factor in the usefulness of the results. PGE will update the data sets to include additional historic generation for existing resources and additional years of synthetic generation for candidate resources. Additionally, PGE hopes to improve the models used to generate the synthetic generation data and to include additional options for incremental resources.
- **Improve load data.** The Company will work to improve the load data used in the adequacy modeling, particularly for the outer years, where PGE used simplified scaling, based on 2021, in this cycle.
- **Examine PGE hydro inputs.** The inputs for PGE hydro plants, in this IRP, remain the same as used in the last several IRPs. PGE bases these inputs on calculations from plant operations under different license and habitat requirements.

- **Time-sequential model.** PGE is examining the possibility of using a time-sequential model in a future IRP cycle. This would allow for improved modeling of energy-limited resources such as energy storage and demand response. As these resources contribute more substantially to the resource stack, the need to improve the modeling of the resource behavior will increase. PGE will have to weigh the benefits associated with a time-sequential model against increased complexity and model run time.
- **Market imports.** The Company will continue to examine the assumptions for short-term and hour-ahead market liquidity in future IRP cycles.
- **Energy efficiency modeling options.** Some stakeholders have expressed an interest in seeing EE treated as a resource in future studies (instead of as a load modifier). While the Company found no simple options for this cycle, it will continue to examine options for modeling EE.
- **Thermal capacity temperature modeling.** Thermal plant capacity varies with temperature. PGE will examine options to improve upon the current monthly average temperature modeling.
- **Further investigate impacts of increased RPS levels.** In the next IRP cycle, the Company plans to include a more extensive examination of capacity needs in outer years with increased RPS levels.

In future IRPs and IRP Updates, PGE will investigate updates to its capacity need and contribution assessment. The Company encourages stakeholder input early in this process as it can be difficult to incorporate substantial changes later in the IRP development cycle. As part of that effort, the Company plans to schedule a technical workshop early in the next IRP cycle.

5.2 Regional Reliability Outlook

While PGE planning metrics provide a high degree of reliability in its power supply, it is also important to understand regional supply and demand fundamentals.[94] The NWPCC performs this analysis for the region. The Council's standard is "[t]he power supply is deemed adequate if its LOLP, five years into the future, is 5 percent or less."[95]

NWPCC notes in its Seventh Plan that "[a]n important finding of the plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulating services will also need to be considered."[96]

Table 5-1 is a summary of NWPCC power supply adequacy assessments from 2010 through 2016. In the most recent assessment, the LOLP for 2021 increased to 10 percent if Colstrip units 1 & 2 remain online through 2021 and 13 percent if Colstrip units 1 & 2 are retired by 2021. Under these conditions, NWPCC identified a resource adequacy need in the region of approximately 1,400 MW in 2021 under its medium load growth forecast. The assessment includes the assumption that the EE targets in the Council's recently released Seventh Power Plan are achieved (1,400 MWa by 2021).

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[94] This section addresses regional power supply without consideration of potential transmission availability. Please refer to Chapter 9, Transmission Options, for a discussion of regional transmission availability.

[95] NWPCC Seventh Power Plan, pg 11-9.

[96] NWPCC Seventh Power Plan, pg 1-4.

TABLE 5-1: NWPCC power supply adequacy assessments

Year Analyzed	Operation Year	LOLP	Observations
2010	2015	5%	Was part of the Council's 6th Power Plan
2012	2017	7%	Imports deceased from 3,200 to 1,700 MW, load growth 150 aMW per year, only 114 MW of new thermal capacity
2014	2019	6%	Load growth 0.6%, over 600 MW new generating capacity, increased imports by 800 MW
2015	2020	5%	Lower load forecast, 350 MW of additional EE savings
2015	2021	8.3%	Early estimate (BPA INC/DEC only) Loss of Boardman and Centralia 1 (~1,330 MW)
2016	2021	10%	2021 loads lower than last year's forecast (~1,500 aMW) but winter peaks are higher (~3,000 MW), using regional INC/DEC reduces hydro peaking by as much as 2,000 MW
2016	2021	13%	Same as above but with Colstrip coal plants 1 and 2 retired (307 MW assigned to serve the region)

Notes: Rows 1-6 from NWPCC Power Supply Adequacy for the 2021 Operating Year, June 8, 2016, Slide 10, https://www.nwcouncil.org/energy/resource/meetings/2016/2016-06-08-steering/. Row 7 from NWPCC Pacific Northwest Power Supply Adequacy Assessment for 2021, September 27, 2016, Document 2016-10, pg 8, https://www.nwcouncil.org/media/7150591/2016-10.pdf.

The composition of power supply resources is changing rapidly across the WECC. In recent years, the region has experienced the retirement of San Onofre Units 2 and 3, and the rapid increase in wind and solar resources. In the next few years, the retirement of coal plants, Diablo Canyon Units 1 and 2, and an even larger expansion of renewables will further alter the composition of the region, increasing the importance of regional planning and coordination.

5.3 Flexible Capacity

5.3.1 Overview

As the penetration of VERs increases on PGE's system and markets continue to evolve across the West, the evaluation of the flexibility of PGE's resource portfolio takes on increasing importance in long-term planning. In particular, VERs require the balance of the fleet to accommodate a larger range of net load conditions, larger ramping events, and larger forecast errors. While there is not yet an industry standard methodology for incorporating flexibility considerations into long-term planning, PGE has engaged in analytical exercises to identify the potential flexibility challenges the system may face in future years and to explore the benefits of new flexible resources within PGE's portfolio.

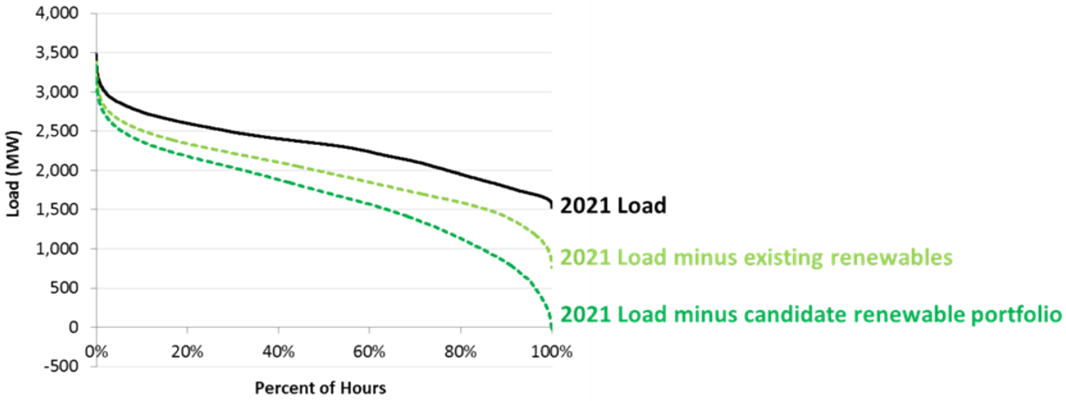
5.3.1.1 Flexibility Challenges at a High Level

Figure 5-12 shows a duration curve developed by Energy & Environmental Economics (E3) of the hourly PGE net load in 2021 under the assumption of

- no renewables (black);
- existing renewables (light green); and
- a 25 percent RPS portfolio (green).

Figure 5-12 shows that while the maximum net load sees fairly small reductions due to renewables, the minimum net load can be dramatically reduced at higher penetrations of renewables and can even drop below zero (i.e., the system is producing more renewable energy than it has demand). If low net load conditions occur during periods of low regional demand, PGE may be required to curtail some renewable energy.

FIGURE 5-12: Net load duration curves for 2021 REFLEX cases[97]



In addition to bringing about lower net load conditions, higher variable resource penetrations also increase the magnitude of ramping events and increase forecast errors. Both of these factors require the ability to more rapidly and more frequently ramp and/or cycle conventional units and to operate them at less efficient set points.

PGE assessed the effects of each of these factors on system operations from the perspective of flexible resource adequacy in the 2013 IRP[98] by relying on the pioneering work of the Northwest Power and Conservation Council.[99] PGE's study consisted of a four step analysis:

1. Using actual one-minute interval load and synthetically developed wind data from 2004, 2005 and 2006 to calculate the net load range, PGE computed the 2015 and 2020 required load range by escalating load at the expected load growth and wind availability with the expected resource additions. No variable resources other than wind were included in the existing and future resource stack.
2. PGE identified the ramping rate required to follow net load by computing the maximum and the minimum minute-to-minute net load delta. This represents a proxy of the ramp-up (maximum delta) and ramp-down (minimum delta) need. The Company repeated this

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[97] Source: E3.

[98] For a detailed description see Chapter 5 of PGE's 2013 IRP, https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/pge-2013-irp-report.pdf?la=en.

[99] Dr. Schilmoeller, "Imbalance Reserves: Supply, Demand, and Sufficiency." Northwest Power and Conservation Council.

procedure for increasing time intervals (two minutes, three minutes, etc.) up to one hour. This identified the demand curve for up and down ramping for up to an hour.

3. PGE estimated the supply curve for up and down ramping (flexible capacity supply), considering its individual resource operational characteristics and hour-to-hour forecast error, and reserve margin requirements.

In 2013, PGE expressed the intention of pursuing additional research on this issue. The flexibility study described in Section 5.3.2, REFLEX Analysis, fulfills this intention.

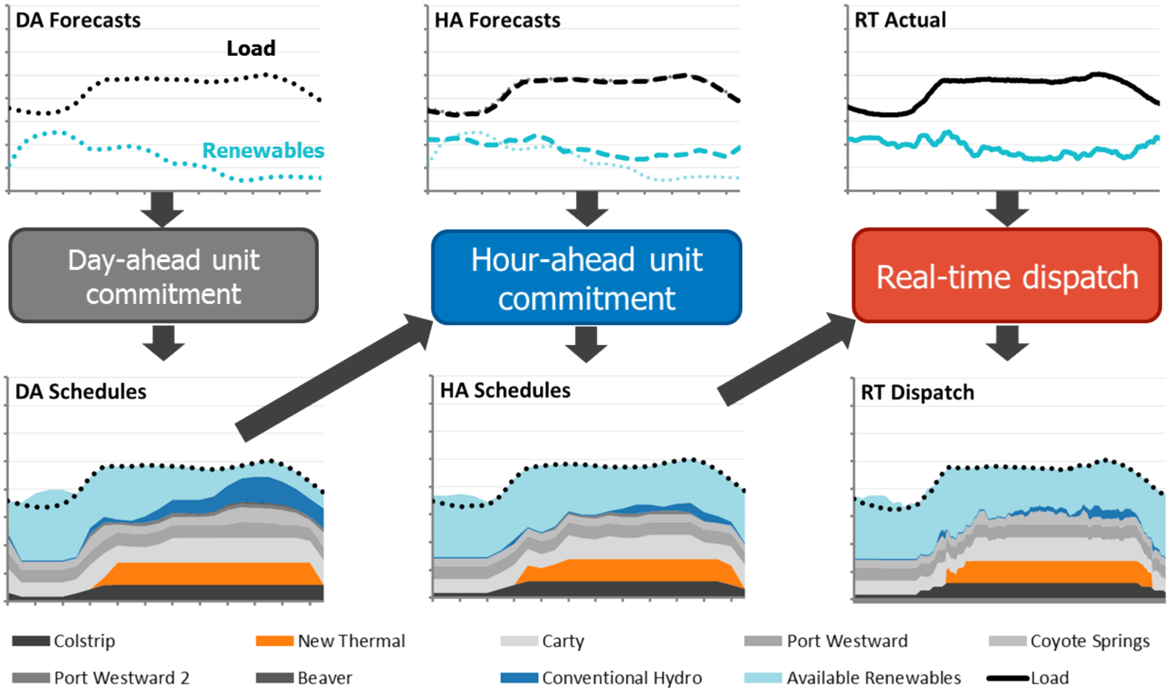
5.3.2 REFLEX Analysis

To explore flexibility challenges on the PGE system as an increasing share of demand is met with renewable resources, the Company conducted a flexibility study with the consulting firm Energy & Environmental Economics (E3) based on a new methodology that took into account all three of the factors described above: the net load range, ramping events, and forecast errors. A summary of the study's methodological approach and findings follows.

5.3.2.1 The REFLEX Model

E3 developed the REFLEX model to evaluate the need for flexible capacity resources on systems with moderate to high penetrations of renewable resources. REFLEX is a three-stage mixed integer programming (MIP) model that optimizes the commitment and dispatch of PGE's resource fleet in the day-ahead (DA), hour-ahead (HA) and real-time (RT) time frames in order to meet the system load with five-minute resolution. Figure 5-13 summarizes the multistage commitment and dispatch modeling framework. The model identifies upward flexibility challenges in the HA and RT stages that arise due to low net load conditions, fluctuations in load and renewable output, and load and renewable forecast errors.

FIGURE 5-13: Schematic of REFLEX three-stage commitment and dispatch modeling



In addition to meeting load, REFLEX also requires the system to hold adequate reserves for contingencies, renewable and load forecast errors, and subhourly fluctuations. In each time step, REFLEX requires the system to commit adequate resources to provide spinning reserves, which are held for contingencies on the system, and upward and downward load following and regulation reserves.[100] Load following reserves are held to accommodate forecast errors and five-minute fluctuations in each commitment stage. The model penalizes load following shortages based on the amount of subhourly unserved energy (for upward shortages) or subhourly curtailment (for downward shortages) expected to result from the inadequate reserve provision. Regulation reserves are held to accommodate fluctuations on timescales shorter than five minutes. Both regulation and spinning reserve violations are penalized at a constant $/MW rate.

In order to increase the range of analyzable system conditions beyond the datasets in which synchronous load and renewable data are available, REFLEX models synthetically-generated days by combining load and renewable shapes that fall within the same month and load-level bin. For each simulated day, REFLEX first draws a day of historical load conditions and then identifies the month and load level bin associated with the drawn day. Next, the model draws: 1) a random day of wind conditions from the set of historical wind data associated with the month and load level bin; and 2) a random day of solar conditions from the set of historical solar data associated with the month and load level bin. This day-draw methodology is illustrated in Figure 5-14. Each day draw consists of the load and renewable day-ahead hourly forecasts, hour-ahead hourly forecasts, and five-minute real-time data over the course of the day of interest as well as the prior day and following day. REFLEX

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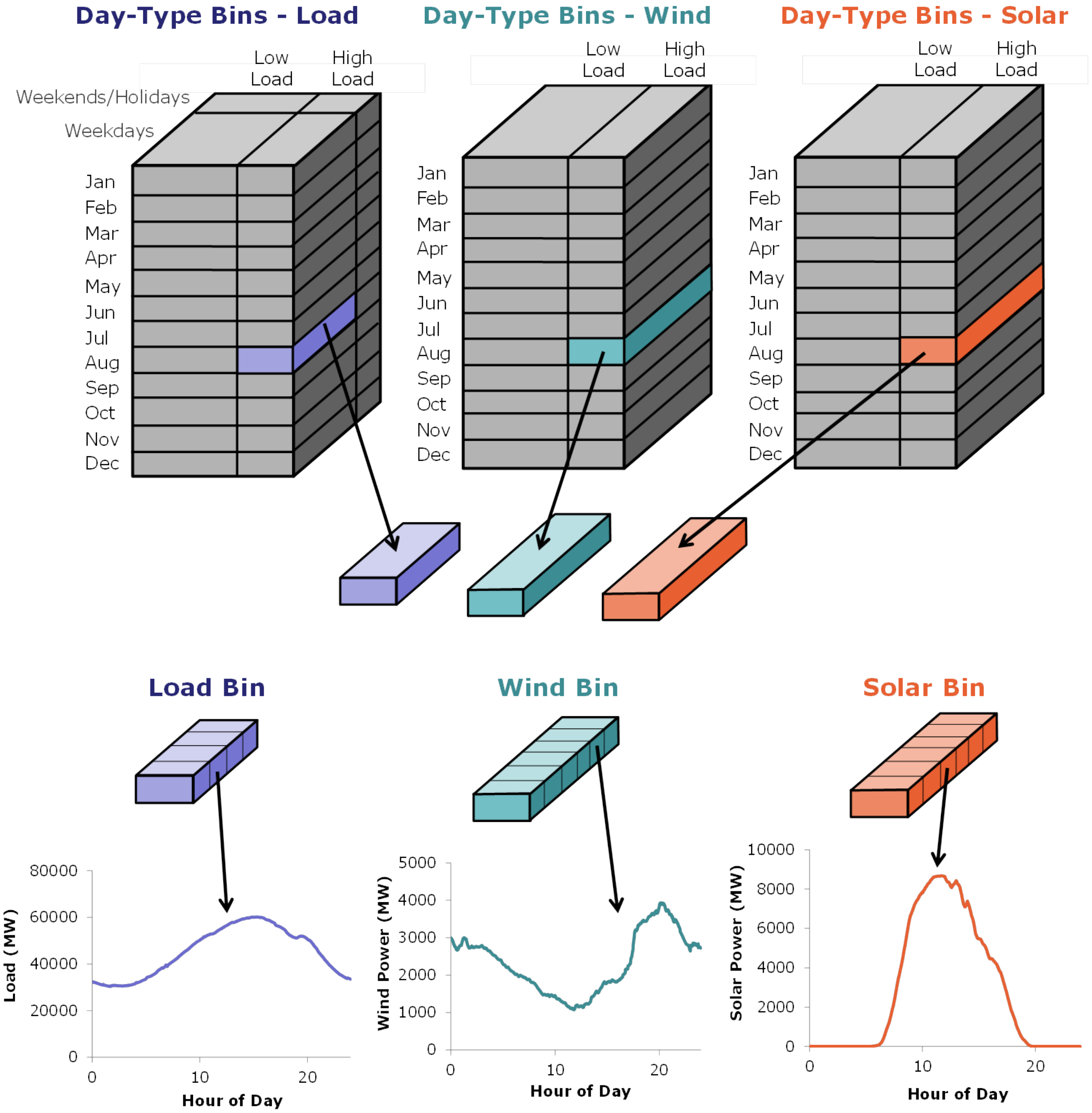
[100] Non-spinning contingency reserves are assumed to be met with distributed standby generation (DSG).

then simulates commitment and dispatch over the full three-day period and removes the first and third days to reduce the impact of model spin-up and edge effects.

FIGURE 5-14: Schematic of REFLEX day-drawing methodology[101]



The REFLEX analysis contains several embedded assumptions, the most critical of which are described below.

- Modeling of PGE as a closed system, with generally no interactions with the market. This assumption is consistent with a traditional resource adequacy perspective; however, limiting the interactions with the market can have a significant impact on the dispatch of PGE's portfolio and on the flexibility challenges experienced by the system.

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[101] Source: E3.

- Scheduling or dynamic dispatch of renewable curtailment occurs at a $/MWh cost penalty. This relieves upward flexibility challenges on the system by allowing the system to overcommit thermal resources to meet reliability requirements.
- Simulation of hydro resources with optimal dispatch in real-time, subject to daily energy, minimum generation, and maximum generation constraints. This treatment neglects explicit constraints related to cascading hydro systems, but is intended to largely mimic historical operating limits across a hydro fleet.
- Load following and regulation reserve requirements in each hour are based on statistical analysis of load and renewable subhourly fluctuations and forecast errors, which do not necessarily align with the system's operating practice.

5.3.2.2 Model Inputs

Primary REFLEX model inputs include:

- The thermal generator stack for the study test year (2021), including operating parameters for each unit related to both cost and operating limits.
- Characterization of flexible hydro resource, including energy availability, minimum generation, maximum generation, and maximum ramp rates under a wide range of hydro conditions. Mid-Columbia hydro conditions were obtained from the NWPCC.
- Fixed hourly shapes for run-of-river hydro systems.
- Synchronous hourly day-ahead and hour-ahead load forecasts as well as five-minute actual load. Load shapes corresponded to the 2021 test year.
- Synchronous hourly day-ahead and hour-ahead renewable forecast as well as five-minute actuals over time periods in which load data is also available. Renewable output data was based on the NREL Western Wind Dataset and the NREL Solar Prospector.
- Hourly load following requirements and load following shortage penalty functions for each commitment stage.
- Regulation requirements for each commitment and dispatch stage.

In addition, for each study, REFLEX relies on a set of penalty values for various flexibility or capacity-related shortages or violations, which appear as proxy resource dispatch. For the PGE flexibility study, these include:

TABLE 5-2: Proxy resources used to identify flexibility challenges in REFLEX

Resource	Description	Cost
DA Off-Peak Capacity	Block capacity scheduled in the DA during off-peak hours; adequate availability assumed to meet resource adequacy requirements.	$6,000/MWh
DA On-Peak Capacity	Block capacity scheduled in the DA during off-peak hours; adequate availability assumed to meet resource adequacy requirements.	$6,000/MWh
DA SuperPeak Capacity	Block capacity scheduled in the DA during super peak hours; 400 MW available in non-summer months, 200 MW available in summer months.	$10,000/MWh
HA Capacity	Dispatchable resource scheduled in HA with no ramp rate limit; unlimited capacity.	$10,000/MWh
RT Capacity	Dispatchable resource available in RT with no ramp rate limit; unlimited capacity.	$10,000/MWh
Unserved Energy	Indicator resource for unmet load.	$50,000/MWh
Curtailment	Scheduled in DA, rescheduled in HA, and available for dispatch in RT to mitigate downward flexibility challenges.	$100/MWh

5.3.2.3 Portfolios

PGE designed three incremental renewable portfolios to investigate portfolio diversity effects while complying with a 25 percent RPS (Portfolios A, B, and C below).[102] In addition, E3 designed a single 50 percent RPS portfolio to gain preliminary insights regarding higher renewable penetrations. Note that the portfolios used in the flexibility analysis do not correspond to specific portfolios evaluated in the IRP. As shown in Table 5-3, Portfolio A meets a 25 percent RPS with only incremental Gorge Wind resources,[103] Portfolio B examines the flexibility-related benefits of including solar photovoltaics in PGE's renewable portfolio, and Portfolio C contemplates the diversity benefits of developing a wind resource in Montana. The 50 percent RPS portfolio represents a doubling of the resources in Portfolio B, including a doubling of existing renewable resources.

TABLE 5-3: Renewable resource portfolios examined in the REFLEX study

MWa	Site Y1 (Gorge)	Site Y2 (Gorge)	Site Y Small (Gorge)	Utility PV	Montana Wind	RPS
Portfolio A	116	150	-	-	-	25%
Portfolio B	-	150	86	30	-	25%
Portfolio C	116	-	-	-	150	25%
50% Portfolio (Portfolio B x 2)	-	300	172	60	-	50%

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[102] Note that these portfolios do not correlate to specific portfolios considered in the IRP portfolio analysis.

[103] The Gorge Wind resources considered in the REFLEX analysis have similar availability to the PNW Wind resources considered in the IRP portfolio analysis.

PGE constructed incremental thermal portfolios from three types of thermal resources, a flexible combined cycle unit (CCCT), frame combustion turbines (Frame CTs), and reciprocating engines (Recips). Table 5-4 summarizes the key operating parameters for these resources as provided by Black & Veatch (see Appendix K, Characterization of Supply-Side Options (Black & Veatch)).

TABLE 5-4: Incremental thermal resource options considered in the REFLEX analysis

Resource	Size (MW)	Commitment Stage	Min Up/Down Time (hrs)	Max Ramp (MW/min)	Pmin (%)	Heat Rate[104] (Btu/kWh)
CCCT	400	Day-ahead	1.5	50	33%	8,318/6,503
Frame CTs	200	Real-time	0.5	40	38%	13,548/9,176
Recips	18	Real-time	0.5	5	7%	12,827/8,437

E3 investigated 24 primary scenarios (indicated by the X's in Table 5-5), each of which consisted of the 2021 base PGE portfolio, an incremental renewable portfolio, and an incremental thermal portfolio (or no incremental thermal). Given that computational limitations prevented the investigation of all possible scenarios, these scenarios were selected in order to provide specific insights via comparison across scenarios. In addition to the resources listed, the DA Capacity resources described in Table 5-2 were also sized for each scenario to ensure resource adequacy from a traditional capacity perspective.

TABLE 5-5: Combinations of renewable and new thermal resource portfolios examined in REFLEX

Renewable Portfolio	No New Thermal	CCCT	Frame CTs		Reciprocating Engines			
		400 MW	200 MW	400 MW	100 MW	200 MW	300 MW	400 MW
Portfolio A (25% RPS – Gorge Wind)	X	X	X	X	X	X	X	X
Portfolio B (25% RPS – Gorge Wind + Solar)	X		X	X				
Portfolio C (25% RPS – Gorge Wind + MT Wind)	X	X	X	X	X	X	X	X
50% RPS (double Portfolio B)	X	X	X	X		X		

In addition to these portfolios, E3 evaluated a 2015 Baseline portfolio that incorporated 2015 load levels and existing resources to provide context for the levels of flexibility challenges identified for the primary portfolios.

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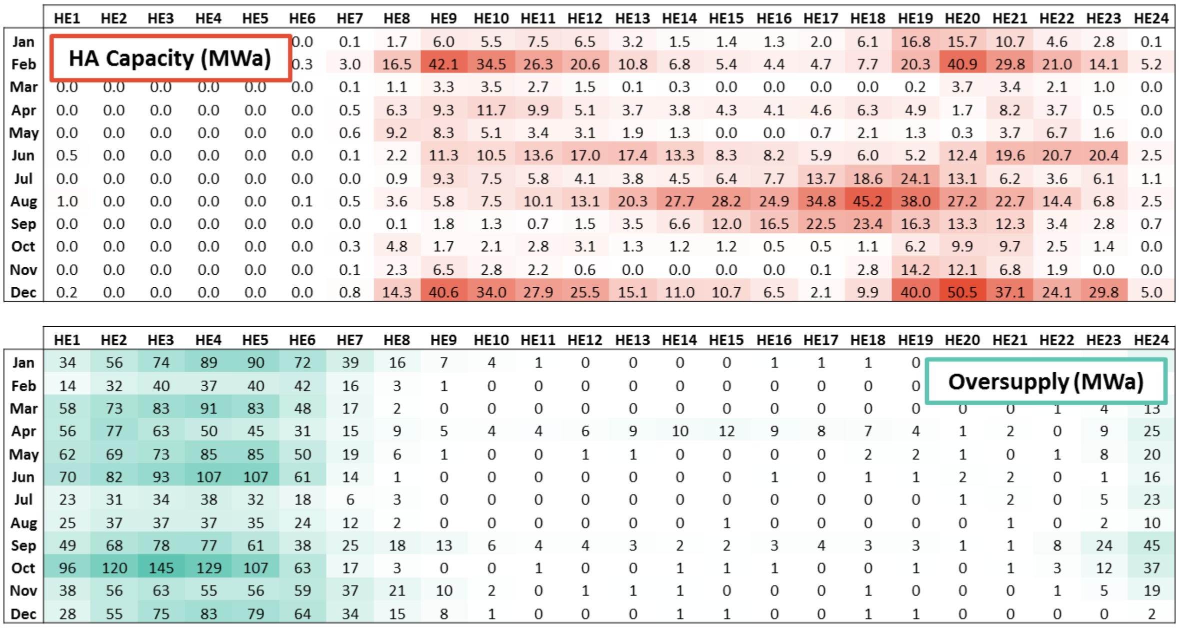
[104] Heat rates listed represent minimum load and max output, respectively.

5.3.2.4 Results

Identified Flexibility Challenges

The REFLEX analysis identified both upward and downward flexibility challenges at 25 percent RPS if no additional resource flexibility is added to the system (i.e., if all capacity needs are met with high strike price capacity contracts). Upward challenges were manifested as reliance on the HA and RT Capacity products due to either forecast errors or large ramping events. As is shown in Figure 5-15, these challenges were identified primarily during peaking hours (morning and late evening peaks during winter months and the evening peak in summer months). In contrast, downward challenges were identified primarily in early morning hours across all months due to low load conditions during periods of high wind output. Downward challenges were manifested in the study as renewable curtailment; however, it is important to note that the REFLEX analysis does not consider opportunities to sell power into other markets, so the identified levels of curtailment should be interpreted as upper bounds given the study assumptions regarding the flexibility of units within the PGE portfolio. Note that while Figure 5-15 reflects the findings for Portfolio A with no incremental flexible capacity, the temporal patterns were similar across all scenarios.

FIGURE 5-15: Seasonal and hourly patterns in identified flexibility challenges[105]



HA Capacity (MWa)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Jan						0.0	0.1	1.7	6.0	5.5	7.5	6.5	3.2	1.5	1.4	1.3	2.0	6.1	16.8	15.7	10.7	4.6	2.8	0.1
Feb						0.3	3.0	16.5	42.1	34.5	26.3	20.6	10.8	6.8	5.4	4.4	4.7	7.7	20.3	40.9	29.8	21.0	14.1	5.2
Mar	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.1	3.3	3.5	2.7	1.5	0.1	0.3	0.0	0.0	0.0	0.0	0.2	3.7	3.4	2.1	1.0	0.0
Apr	0.0	0.0	0.0	0.0	0.0	0.0	0.5	6.3	9.3	11.7	9.9	5.1	3.7	3.8	4.3	4.1	4.6	6.3	4.9	1.7	8.2	3.7	0.5	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0	0.6	9.2	8.3	5.1	3.4	3.1	1.9	1.3	0.0	0.0	0.7	2.1	1.3	0.3	3.7	6.7	1.6	0.0
Jun	0.5	0.0	0.0	0.0	0.0	0.0	0.1	2.2	11.3	10.5	13.6	17.0	17.4	13.3	8.3	8.2	5.9	6.0	5.2	12.4	19.6	20.7	20.4	2.5
Jul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	9.3	7.5	5.8	4.1	3.8	4.5	6.4	7.7	13.7	18.6	24.1	13.1	6.2	3.6	6.1	1.1
Aug	1.0	0.0	0.0	0.0	0.0	0.1	0.5	3.6	5.8	7.5	10.1	13.1	20.3	27.7	28.2	24.9	34.8	45.2	38.0	27.2	22.7	14.4	6.8	2.5
Sep	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.8	1.3	0.7	1.5	3.5	6.6	12.0	16.5	22.5	23.4	16.3	13.3	12.3	3.4	2.8	0.7
Oct	0.0	0.0	0.0	0.0	0.0	0.0	0.3	4.8	1.7	2.1	2.8	3.1	1.3	1.2	1.2	0.5	0.5	1.1	6.2	9.9	9.7	2.5	1.4	0.0
Nov	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.3	6.5	2.8	2.2	0.6	0.0	0.0	0.0	0.0	0.1	2.8	14.2	12.1	6.8	1.9	0.0	0.0
Dec	0.2	0.0	0.0	0.0	0.0	0.0	0.8	14.3	40.6	34.0	27.9	25.5	15.1	11.0	10.7	6.5	2.1	9.9	40.0	50.5	37.1	24.1	29.8	5.0

Oversupply (MWa)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Jan	34	56	74	89	90	72	39	16	7	4	1	0	0	0	0	1	1	1	0					
Feb	14	32	40	37	40	42	16	3	1	0	0	0	0	0	0	0	0	0	0					
Mar	58	73	83	91	83	48	17	2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	4	13
Apr	56	77	63	50	45	31	15	9	5	4	4	6	9	10	12	9	8	7	4	1	2	0	9	25
May	62	69	73	85	85	50	19	6	1	0	0	1	1	0	0	0	0	2	2	1	0	1	8	20
Jun	70	82	93	107	107	61	14	1	0	0	0	0	0	0	0	1	0	1	1	2	2	0	1	16
Jul	23	31	34	38	32	18	6	3	0	0	0	0	0	0	0	0	0	0	0	1	2	0	5	23
Aug	25	37	37	37	35	24	12	2	0	0	0	0	0	0	1	0	0	0	0	0	1	0	2	10
Sep	49	68	78	77	61	38	25	18	13	6	4	4	3	2	2	3	4	3	3	1	1	8	24	45
Oct	96	120	145	129	107	63	17	3	0	0	1	0	0	1	1	1	0	0	1	0	1	3	12	37
Nov	38	56	63	55	56	59	37	21	10	2	0	1	1	1	0	0	0	1	0	0	0	1	5	19
Dec	28	55	75	83	79	64	34	15	8	1	0	0	0	1	1	0	0	1	1	0	0	0	0	2

An example of an operating day highlights two of the primary sources of flexibility challenges on the system. Figure 5-16 shows the DA hourly scheduled dispatch, the HA hourly schedules, and the five-minute RT actual dispatch for an example day in December for Portfolio A with no additional flexible capacity. On this day, the DA forecast anticipates relatively high wind output throughout the morning that ramps down during daylight hours. However, within the day, the forecasted morning wind event does not occur, leading to reliance on the expensive HA Capacity product (shown in red in the "HA"

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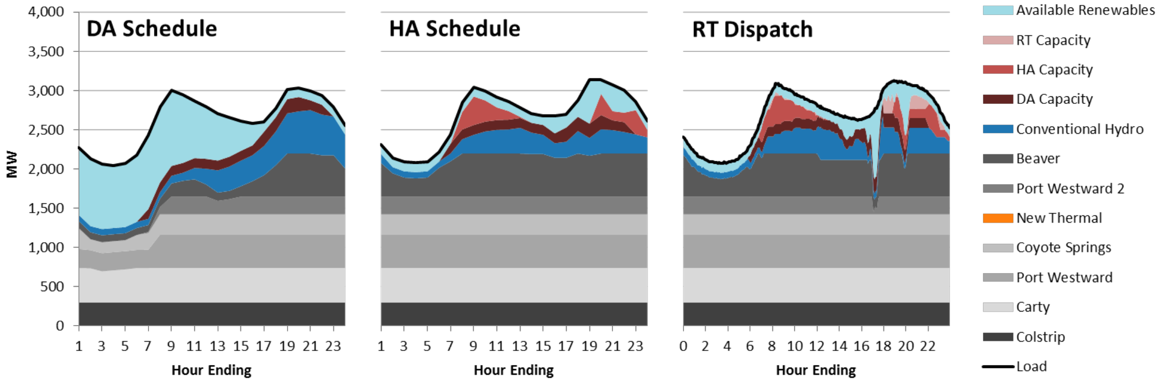
[105] Source: E3.

plot) in order to meet the load. In RT, two large spikes in wind output are observed in the evening. The system largely accommodates these spikes in power output by shutting down and starting up units at Beaver and Port Westward 2 and by ramping the hydro fleet; however, additional flexibility at the five-minute level is required in the upward direction to mitigate HA wind forecast errors. This is shown in the "RT" plot as dispatch of the RT Capacity resource in light pink. This day illustrates a finding that was generally consistent across the scenarios – that the PGE system has considerable ramping capability, but that renewable forecast errors and the timescales over which resource commitment decisions are made have the potential to constrain the ability of the system to fully integrate variable renewable resources at higher penetrations if no additional flexible capacity is procured.

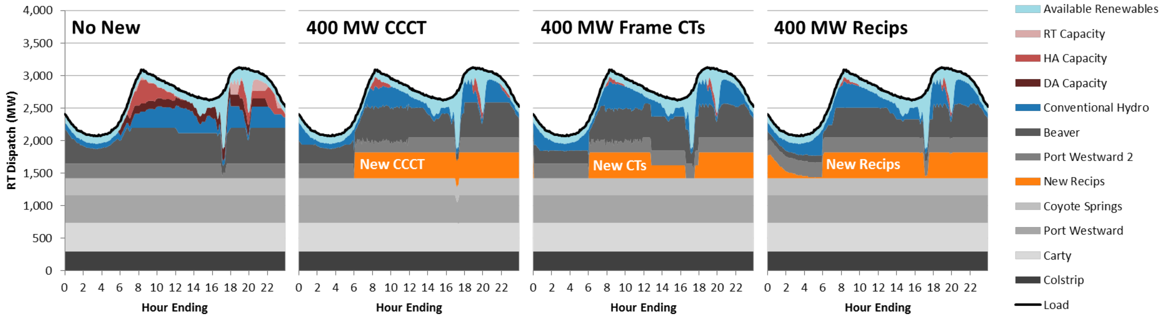
FIGURE 5-16: Hourly DA schedule, HA schedule, and RT dispatch on challenging day[106]



Impacts of New Thermal Resources

The addition of thermal resources to meet a portion of the capacity shortage identified in Section 5.1, Capacity Adequacy and Capacity Contribution, was found to have a significant impact on the operational flexibility of the PGE portfolio as a whole. Figure 5-17 shows how the dispatch on the same day shown in Figure 5-16 is affected by the addition of a 400 MW combined cycle unit, 2x200 MW of frame combustion turbines and 22x18.2 MW of reciprocating engines, each tested separately.

FIGURE 5-17: Impact of 400 MW of new thermal resource additions on the day shown in Figure 5-16[107]



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[106] Source: E3.

[107] Source: E3.

While the three thermal resource types have different operating behavior on the example day, the reduction in reliance on expensive HA and RT Capacity products is similar across all resource addition scenarios. In the scenario in which a CCCT is added, the CCCT is committed in the DA stage based on economics and is dispatched in RT at full load across all time steps in which it is committed. The capabilities of the CCCT in coordination with the other units in the fleet largely eliminate the reliance on the HA Capacity product and completely eliminate the reliance on the RT Capacity product on this example day. Meanwhile, the downward flexibility required to accommodate the evening wind spikes is provided largely by Beaver, Port Westward 2, and the hydro fleet. If frame CTs are added to the system instead of a CCCT, then the same upward flexibility benefits are observed, but the frame CTs also shift some of the burden for downward flexibility from Beaver and Port Westward 2 to the new frame units. Similarly, the reciprocating engines have a very different dispatch profile from the CCCT or frame units, but have a similar impact on flexibility challenges and redistribute the downward flexibility burden among units in the portfolio.

The findings with respect to technology differentiation in the example day described above generally hold across the full set of simulated days. The annual average RT imbalance (or reliance on the RT Capacity product) is shown across all of the conventional resource addition options for Portfolio A in the left panel of Figure 5-18. While significant RT imbalance is identified with no thermal additions (i.e., the full capacity shortage identified in Section 5.1, Capacity Adequacy and Capacity Contribution, is met with high strike price capacity contracts), incremental thermal resource additions (each of which displaces the expensive DA capacity product on a 1-for-1 basis) dramatically reduce the simulated imbalance regardless of the operating characteristics of the new thermal resource. A small amount of technology differentiation with respect to system upward flexibility is identified at the 400 MW level, at which the frame CTs and reciprocating engines have similar performance, but the CCCT has slightly less capability for mitigating upward challenges. These findings suggest that at 25 percent RPS, approximately 400 MW of dispatchable resources will be required to avoid significant real-time imbalances on the system, but that this need could be met with a variety of technologies.

FIGURE 5-18: Expected RT imbalance and oversupply for Portfolio A with thermal resource additions[108]

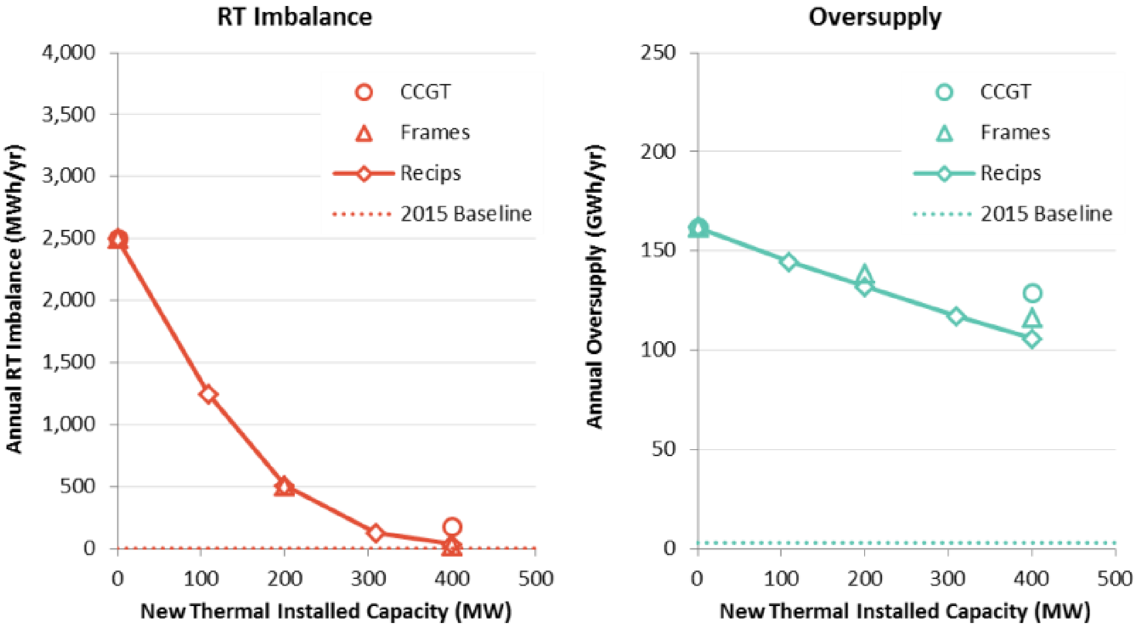

Figure 5-18 also shows the identified renewable curtailment or oversupply potential across the Portfolio A scenarios (right panel) and points to a larger degree of technological differentiation with respect to downward flexibility challenges than upward challenges. This finding is largely due to the economic penalties associated with upward versus downward flexibility shortages. Upward shortages are penalized in the model at levels associated with unserved energy ($50,000/MWh in this study), while downward shortages are penalized at $100/MWh to reflect the approximate net cost of replacing curtailed renewable energy with incremental renewables. This economic asymmetry drives the system to tend to overcommit units in anticipation of renewable forecast errors in order to maintain reliability. As a consequence, when renewable output exceeds forecasted levels, resources must ramp or shut down within the day to accommodate the extra renewable energy. While a frame CT or reciprocating engine can shut down within the day, the CCCT modeled in this analysis must maintain its commitment schedule within the operating day and can only ramp down to its minimum stable level in any hour in which it is scheduled to operate.[109] These operating limits lead to a slightly increased potential for renewable curtailment when incremental capacity needs are met with less flexible units relative to more flexible units.

The thermal resource addition scenarios suggest:

- Upward flexibility challenges associated with increased renewable penetrations can be largely mitigated by procuring new thermal resources or firm mid-stack options in order to meet the capacity shortage. An important caveat is that at times, the REFLEX model schedules significant amounts of upward reserves in order to respond to renewable forecast

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[108] Source: E3.

[109] While some CCCTs are capable of adjusting commitment decisions within the operating day, combined cycle units were not modeled with this capability in REFLEX as an approximation to the within-day operating constraints that are imposed by day-ahead gas nominations.

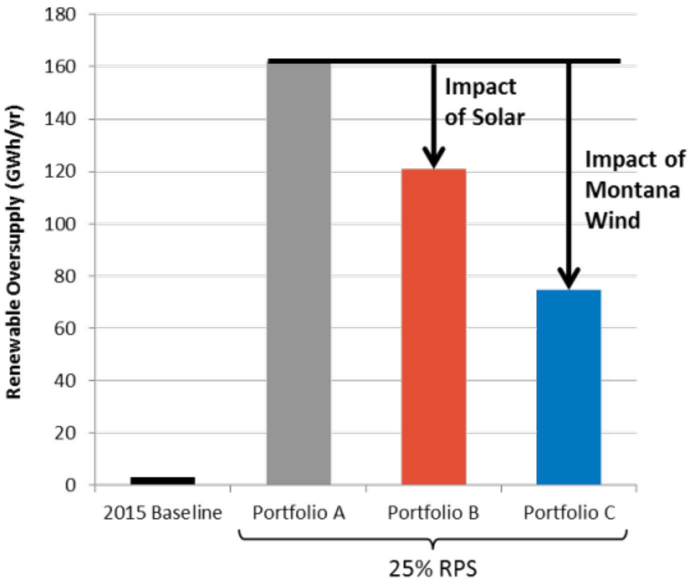
errors and fluctuations within the day. Operating the system to ensure reliability with higher penetrations of wind may therefore require units to operate at less efficient set points or to operate during unfavorable market conditions, which may increase the cost of operating the system. These economic considerations were not fully explored in this study because the PGE portfolio was modeled as an isolated system.

- The flexibility of new resource additions may have a larger impact on downward flexibility challenges than upward challenges. Meeting the capacity need with largely inflexible resources may require over-commitment in the day-ahead in order to maintain reliability, which will increase the likelihood of experiencing renewable curtailment events.

Impacts of Renewable Portfolio Diversity

Portfolios B and C were used to investigate the impact of increasing renewable portfolio diversity relative to Portfolio A, in which incremental renewable need is met with Gorge wind resources. Portfolio B considers a scenario in which 30 MWa of the incremental renewable portfolio is met with solar resources, while Portfolio C considers a scenario in which 150 MWa of the incremental renewable portfolio is met with a wind resource in Montana. The flexibility value of these resources is derived from both the potential for complementarity in output shapes and from the reduction in portfolio-wide forecast errors. These factors reduce upward flexibility violations associated with more diverse renewable portfolios when no incremental dispatchable resources are added to the system. Once the capacity need has been met, the bigger impact may be in the potential to avoid renewable curtailment. This impact is illustrated in Figure 5-19 on a non-normalized basis. While the impact of Montana Wind appears to be larger in Figure 5-19 than the impact of Solar, recall that the Montana Wind addition in Portfolio C is five times larger than the solar addition in Portfolio B. On a per-MWa basis, solar was found to have a larger avoided curtailment benefit than Montana wind, during the 2021 test year.

FIGURE 5-19: Renewable oversupply potential under 25 percent RPS and no new thermal resource additions[110]



Insights at 50 Percent RPS

A preliminary analysis aimed to identify how the flexibility challenges identified at 25 percent RPS might be affected with a higher renewable penetration. As described above, the 50 percent RPS portfolio consists of all of the renewable resources included in Portfolio B (including existing renewables), each with double the capacity. The 50 percent RPS scenario also makes use of the same 2021 test year that was used to investigate the 25 percent RPS. It should be acknowledged that PGE anticipates considerable changes to several of the input assumptions of this analysis prior to realizing a 50 percent RPS on the system in 2040. In the time frame relevant to a 50 percent RPS, PGE anticipates broad changes to both the resource stack and load characteristics, potentially including deployment of new energy storage and demand response technologies, as well as broad changes to markets across the West, both in terms of the resource fleets in neighboring jurisdictions and the interactions between utilities in the West. With this in mind, the 50 percent RPS findings are not intended to reflect a forecast, but instead are used to glean high-level observations regarding future demands for flexibility.

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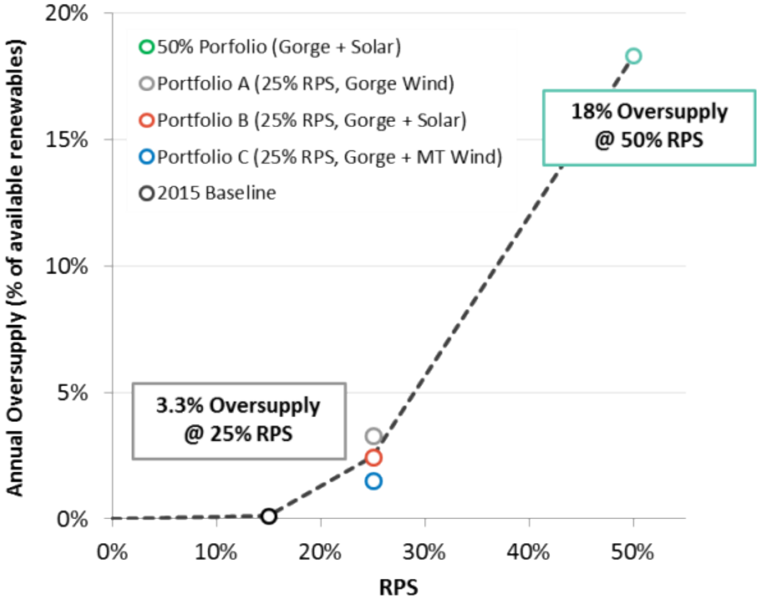
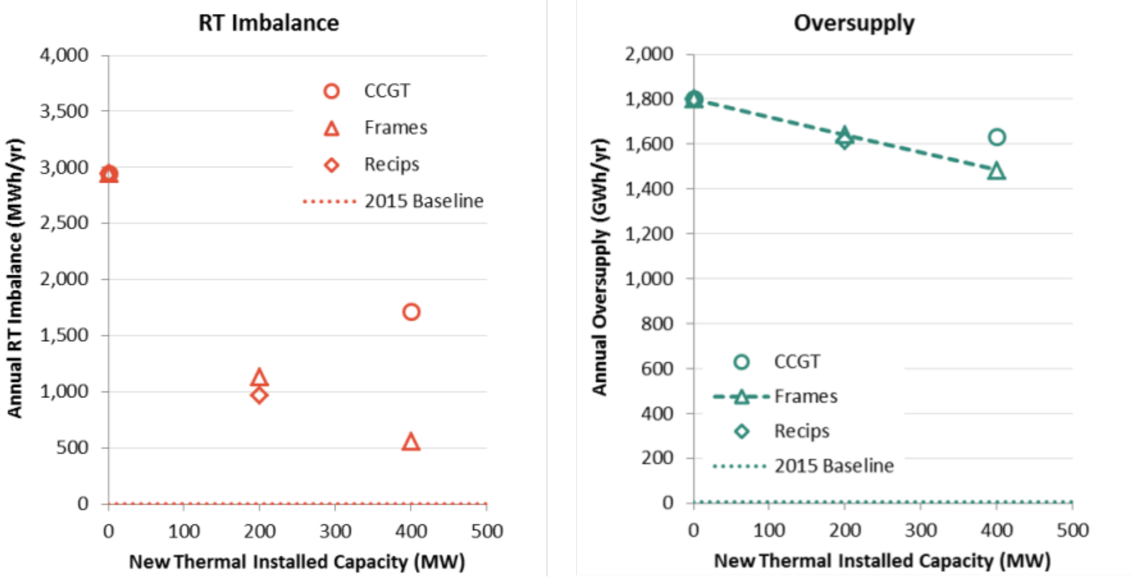
[110] Source: E3.

FIGURE 5-20: Renewable oversupply potential as a function of RPS[111]



In the 50 percent RPS scenario, both upward and downward flexibility challenges were exacerbated relative to the 25 percent RPS scenarios and the primary challenge in integrating renewables was identified as managing renewable oversupply. Potential curtailment levels (as shown in Figure 5-20) were found to exceed 18 percent of the available renewable energy absent the impacts of future resource, technological, and market evolution described above.

FIGURE 5-21: Expected RT Imbalance and oversupply for 50% portfolio with thermal resource additions



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[111] Source: E3.

While greater differentiation in the flexibility impacts of thermal resource options was observed in the 50 percent RPS scenario relative to the 25 percent RPS scenarios, thermal resource additions alone did not mitigate significant levels of curtailment (see Figure 5-21). These findings suggest that as PGE procures additional renewables to meet RPS obligations in the 2030s, management of oversupply through market interactions, energy storage, and/or advanced demand response will be critical to minimizing the cost impacts associated with meeting RPS obligations. These findings also reinforce the need for continued engagement and analysis regarding the flexibility of the system as PGE plans for future resource needs.

5.3.2.5 Conclusions

The REFLEX study provides insights regarding both mid-term and long-term challenges to ensuring that PGE has adequate operational flexibility to integrate renewables while maintaining system reliability. The analysis finds that mid-term flexibility needs are moderate, but increase as the renewable penetration increases.

At 25 percent RPS, provided that PGE has access to approximately 400 MW of incremental dispatchable resources, upward flexibility challenges can be largely mitigated (as shown in Figure 5-18). Dispatchable resources in this context refer to firm resources that have the characteristics of a CCCT, frame CT, or reciprocating engine. Contracts that provide capacity in the day-ahead at a high strike price were not adequate to meet this flexibility need because they were not dispatchable within the day and were unable to relieve the units at Beaver and Port Westward 2 from providing energy (rather than flexibility) to the system on flexibility constrained days. With respect to upward flexibility, the study did not identify a significant differentiation between the three incremental thermal technologies that were tested once this minimum dispatchability requirement was met. This lack of differentiation is partially due to the flexibility provided to the system by existing hydropower and thermal resources.

Greater technological differentiation is observed with respect to downward flexibility challenges. While the analysis did not consider opportunities to sell excess renewable generation, curtailment of up to 3.3 percent of the available renewable energy was observed in the 25 percent RPS scenarios. Within the analysis, this observed curtailment could be reduced by increasing the diversity of the renewable portfolio or meeting the capacity need with more flexible resources.

Fewer scenarios were designed to explore a future with a 50 percent RPS, but the preliminary investigation of the possible flexibility challenges associated with a 50 percent RPS identified the potential for large amounts of renewable curtailment if integration solutions are not pursued. Notably, while the benefits of flexible thermal resources relative to inflexible resources are more apparent at 50 percent RPS than at 25 percent RPS, substantial curtailment potential remains at high renewable penetrations even with the inclusion of incremental flexible thermal resources. The oversupply or curtailment events observed at 50 percent RPS suggests that by 2040, PGE will need a diverse set of options to provide downward flexibility, potentially including energy storage and advanced demand response. In addition, PGE anticipates that the evolution of markets across the West will impact the ability of PGE to alleviate renewable integration challenges.

5.3.2.6 Inclusion in 2016 IRP

The findings of the flexibility analysis are incorporated into the Action Plan through the requirement that approximately 400 MW of incremental resource procurement be comprised of dispatchable resources. Consistent with the analysis, a qualifying dispatchable resource may have operational capabilities similar to a combined cycle, frame combustion turbine, or reciprocating engine to meet this requirement. Though not explicitly tested, other dispatchable low variable cost resources, like hydro or energy storage, would likely contribute to meeting this dispatchability requirement if they are available to be called in anticipation of flexibility challenges in the day-ahead and re-dispatched within the day. Very high variable cost or call-limited resources that cannot be called within an hour do not provide adequate dispatchability to meet this requirement. For example, a capacity contract for an expensive call option in the day-ahead may provide traditional capacity to the system, but this type of resource cannot be responsive to the within-day forecast errors or subhourly variability that causes the upward flexibility deficiencies described in the study.

PGE also considered incorporation of a scoring metric to capture the renewable curtailment implications of various renewable and dispatchable technologies. In cooperation with stakeholders, PGE ultimately excluded this metric from the scoring process due to the following concerns:

1. The REFLEX analysis considers PGE as an isolated system and does not quantify the potential of the market to absorb some portion of the renewable energy subject to curtailment if PGE could not integrate this energy on to the PGE system. The curtailment identified in the study, therefore, represents an upper bound.
2. The high levels of curtailment potential identified in the outer years, as PGE approaches the 50 percent RPS target, are unlikely to materialize given the rate of technological progress observed in the areas of energy storage and advanced demand response as well as ongoing evolution of markets across the West. This observation led to a concern that the outer-year results might disproportionately skew portfolio scoring if PGE included potential renewable curtailment as a metric.
3. The Company and stakeholders discussed the appropriate cost to associate with renewable curtailment—in the context of the REFLEX analysis—but, there has not been a specific effort to incorporate the cost of renewable curtailment into the NPVRR of PGE's IRP portfolios. PGE acknowledges that, should curtailment arise on the system, there may be added costs to ensure compliance with RPS obligations in the future. The treatment of these potential costs in the IRP is an important topic for future discussion with stakeholders.

The topics of renewable integration, curtailment, and the economics of flexible resources will be increasingly important as PGE meets a growing share of its energy needs with renewable resources. The Company views the flexibility study described in this chapter and the energy storage evaluation presented in Chapter 8 as important steps toward integrating these issues into resource planning decisions, but also sees opportunity to improve upon these methods in future IRPs. In particular, PGE plans to engage stakeholders in a discussion of how to appropriately integrate flexibility-related operational considerations in portfolio analysis in future IRP cycles given the long-term uncertainties described above and the computational complexity of studies like the REFLEX analysis and the energy storage evaluation. Subsequent sections provide discussions of the computational insights and challenges.

5.3.3 Flexibility Modeling Next Steps

The methodology described above represents an incremental step toward full incorporation of long-term flexibility considerations into IRP portfolio analysis. PGE seeks to establish a more integrated approach to assessing the impacts of flexibility needs on resource evaluation in future IRPs. Toward this end, PGE is considering the extent to which the Company can use internal or third party modeling tools in an ongoing process to evaluate flexibility needs as the resource fleet, system conditions, and Western markets evolve. In particular, PGE has identified the following functionality as critical to future flexibility modeling efforts:

- Treatment of optimal unit commitment and dispatch at various stages (day-ahead, hour-ahead, real-time) to capture the effects of forecast errors and operational decision-making with imperfect information;
- Ancillary service constraints, including spinning and non-spinning reserves, and upward and downward regulation and load following requirements;
- Treatment of market interactions – in particular the ability to capture the capability of the system to schedule market purchases in the day-ahead and constraints on the ability to sell energy in all stages;
- Energy storage modeling, including differential ancillary services treatment for batteries versus pumped storage systems;
- Multi-day constraints to model long-start units and hydro storage; and
- The ability to run the model internally so that flexibility modeling can be undertaken in a more integrated fashion with portfolio evaluation in the future.

Table 5-6 provides a comparison of these criteria across the three modeling platforms currently used by PGE. This comparison indicates that the internal Resource Optimization Model (ROM), which PGE first developed to calculate the wind integration cost adder, has promise to contribute to flexibility analysis both in future IRPs and on an ongoing basis. ROM has much of the same functionality utilized in the REFLEX study and has additional enhancements that are particularly relevant to the PGE system, including explicit representation of PGE’s cascading hydro resources and additional operational costs on thermal units associated with cycling behavior.

TABLE 5-6: Comparison of existing modeling platforms for future flexibility analysis

Functionality	Priority	REFLEX	AURORA	ROM
DA → HA → RT unit commitment and dispatch	Very high	Implemented	Partial functionality	Implemented
Ancillary service requirements	Very high	Implemented	Partial functionality	Implemented
PGE-specific unit constraints & costs	Very high	Partially captured	Partial functionality	High functionality
Treatment of market interactions	Very high	Fixed prices and constraints	Full WECC representation	Supply curves
Energy storage capabilities	High	Available functionality	Partial functionality	In development
Hydro modeling	High	Fleet-wide constraints	Unit-level heuristics	Cascading system
Ability to run model internally	High	None	Established	Established
Stochastic treatment of system conditions	Low	Implemented	Available	None

PGE intends to continue to evaluate flexibility needs on the system and to incorporate the value of flexibility into resource decisions in a more integrated fashion. The new analytical capabilities that PGE and third parties are developing to evaluate flexibility will not only contribute to the IRP process, but will also help to establish a framework for understanding the value of new technologies like energy storage and advanced demand response in the future.

5.3.4 Flexible Capacity Operating Requirements for EIM

In addition to the flexibility study described in this chapter, PGE has considered the flexibility implications of joining the Energy Imbalance Market (EIM). One component of the EIM is the flexible ramping sufficiency test. This test ensures the ramping capability of the generating resources that PGE bids into the market can meet the EIM balancing authority's flexible ramping requirement. In order to ensure that PGE is able to meet the requirements of the flexible ramping sufficiency test, PGE installed automatic generation control (AGC)[112] on the majority of the Company's generating resources. PGE is also conducting tests to assess the ramping capabilities of each generating resource to ensure the accurate reflection of these capabilities in the CAISO's market model. While PGE believes that the current generation fleet will be sufficient to meet its flexible ramping requirements in the short term, the Company plans to continue evaluating these requirements, particularly in light of increased penetrations of variable resources.

In addition, the Company is pursuing capability to aggregate AGC over multiple units and provide AGC capability as a portfolio instead of on a unit by unit basis. By aggregating AGC across multiple units, PGE will see benefits by both increasing the amount of regulating capacity available at a given

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[112] AGC is "equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction." Glossary of Terms Used in NERC Reliability Standards, NERC (May 17, 2016) (NERC Glossary), available at http://www.nerc.com/files/Glossary_of_Terms.pdf.

time and also reducing the per-unit cycling burden. PGE is pursuing the technical and security upgrades necessary to implement this project.

5.4 Renewable Portfolio Standard – REC Obligation and Production

Oregon's Renewable Portfolio Standard (RPS) requires that a portion of PGE's retail load be served by qualifying renewable resources. Oregon recently passed SB 1547, updating components of the original RPS legislation, including the annual obligations for renewable energy credits (RECs). A discussion of RPS legislation is included in Chapter 3, Planning Environment.

The RPS requirements increase from 15 percent to 50 percent in 2040, as shown in Table 5-7. From 2017-2019, PGE projects a slight surplus in annual RECs produced compared to the annual obligation if no additional resource actions are taken (Figure 5-22). PGE projects a deficit beginning in 2020 when the obligation increases to 20 percent. The deficit expands through 2040 due to increasing requirement levels, load growth, and contract expirations. PGE will need to significantly expand its RPS portfolio to remain in compliance with the annual obligations. Chapter 10, Modeling Methodology, provides the Company's strategy for RPS compliance.

TABLE 5-7: PGE's projected RPS REC obligation and production[113]

	2017	2020	2025	2030	2035	2040
RPS Obligation %	15%	20%	27%	35%	45%	50%
PGE REC Obligation, MWa	309	417	600	828	1135	1347
PGE REC Production, MWa	338	386	387	378	330	302

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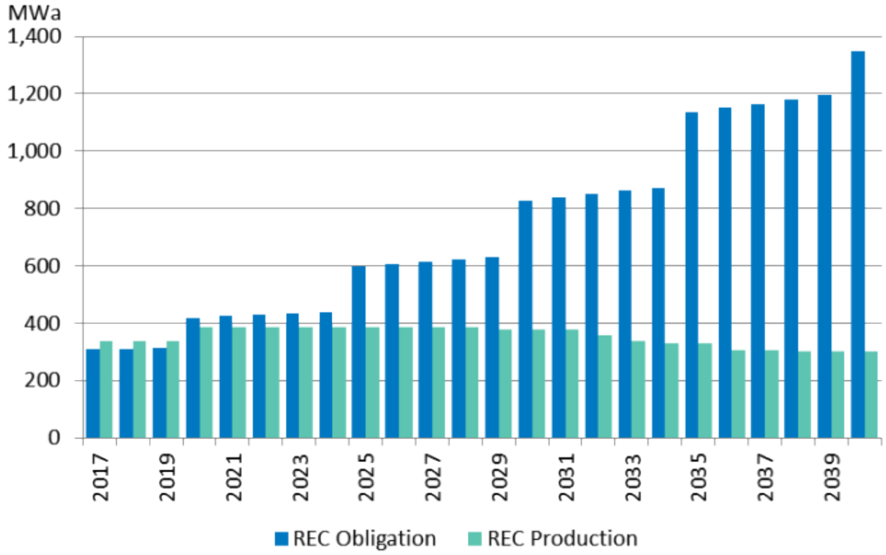
[113] PGE's RPIP, July 2016.

FIGURE 5-22: PGE's projected RPS REC obligation and production[114]



PGE produces or receives RECs from qualified resources and contracts, including Biglow Canyon, Tucannon River Wind, Outback Solar, and several QF contracts. Appendix D, Existing Resources, contains information about PGE's current and contracted resources. Information about historical and projected REC production by resource is provided in PGE's Renewable Portfolio Implementation Plan (RPIP). The latest plan was filed in July 2016.

RPS legislation established provisions for "banking" RECs to allow RECs produced in one year to be retired in a later year. PGE's REC bank balance at the end of 2015 was approximately 896 MWa.[115] PGE discusses its REC bank in Chapter 10, Modeling Methodology, as part of the Company's RPS compliance strategy. REC banking provisions under SB 1547 are described in Chapter 3, Planning Environment.

5.4.1 Solar Photovoltaic Capacity Standard

The Solar Photovoltaic Capacity Standard is a legislative mandate that by January 1, 2020, PGE must own or contract to purchase 10.9 MW of solar PV capacity. Individual solar systems must be between 500 kW and 5 MW in size. PGE's existing portfolio meets the requirements with resources such as Baldock Solar, Bellevue Solar, Yamhill Solar, Outback Solar, and Steel Bridge Solar. Appendix D, Existing Resources, describes PGE's solar resources.

5.5 Energy Load-Resource Balance

The energy load-resource balance (LRB) compares the expected energy availability of PGE's resources (generating plants, contracts, and EE) to the expected annual average load under normal hydro and weather conditions for each year of the IRP analysis.

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[114] PGE's RPIP, July 2016.

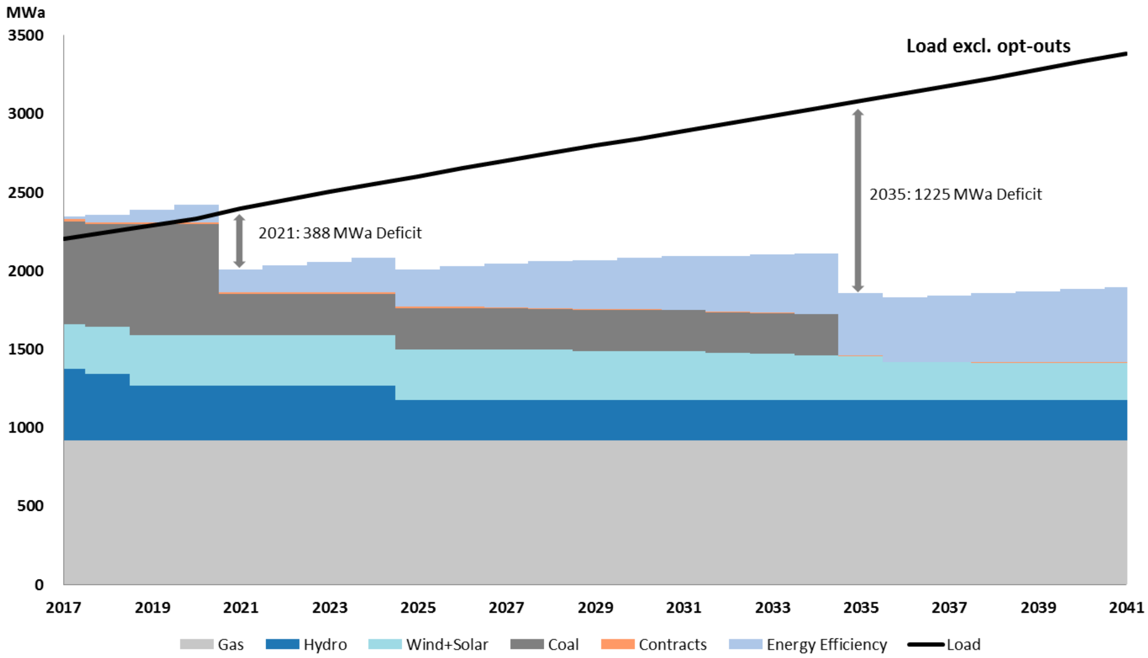
[115] PGE's RPIP, July 2016.

The energy LRB for this IRP relies on an April 2015 assessment of projected plant availability, contracts executed as of May 2016, and the June 2015 load forecast.[116] The methodology for constructing the energy LRB remains the same as used in the 2013 IRP, including the following:

- Load is calculated before making reductions to reflect post-2016 EE. PGE then includes EE as part of its resource portfolio.
- PGE does not include the Beaver and Port Westward 2 plants, because the Company primarily uses these plants for peaking and flexibility. Similarly, duct firing capabilities are not included.
- Thermal plant availability includes adjustments for forced outage rates and maintenance.

Figure 5-23 shows PGE's energy LRB for 2017 through 2041. The layers show the resource stack by category and the line shows the load (before EE and excluding opt-outs). PGE expects a small surplus in 2017, moving to approximate balance in 2020. The system transitions to a 388 MWa deficit in 2021, after Boardman ceases coal-fired operations. The energy gap continues to grow due to load growth and contract expirations (partially offset by growth in EE savings), increasing to a deficit of 1225 MWa in 2035 after the Colstrip units are removed from the resource stack. Figure 5-23 is provided in tabular form in Appendix P, Load Resource Balance Tables.

FIGURE 5-23: PGE's projected annual average energy load-resource balance



PGE used the energy LRB as a guide for sizing resources in portfolio construction, as discussed in Chapter 10, Modeling Methodology. PGE examined portfolios that were short, balanced, and long to the energy gap identified in the energy LRB. PGE notes that the usefulness of the energy LRB in determining need has diminished in recent years. Significant changes to technology, fuel prices, markets, and regulation have led to increased quantities of variable resources and substantial

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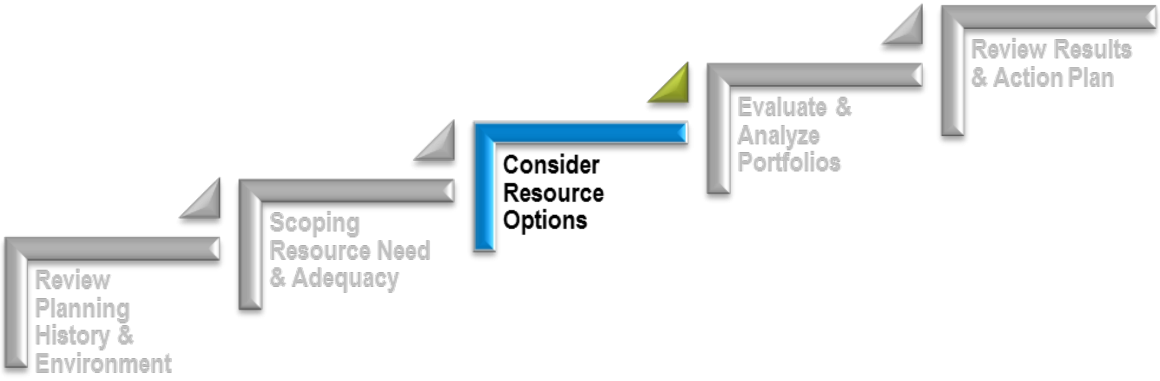
[116] Descriptions of PGE resources and contracts are provided in Appendix D, Existing Resources.

adjustments to the traditional order of the dispatch stack, making the energy exposure to market much more complex than captured through a static annual energy LRB. The energy position of a portfolio is a price risk that is better examined through portfolio analysis. Chapter 12, Modeling Results, discusses portfolio results, including cost risk of portfolios with varying energy positions.

PGE anticipates that future IRPs will continue to focus on examining energy positions through portfolio performance across futures while resource need will be defined by capacity, flexibility, and RPS requirements.

Part III. Resource Options



CHAPTER 6. Demand Options

PGE continues to analyze all identified demand-side options as part of its integrated resource portfolio strategy. Demand-side management options include all resources which reduce or shift end-use load at a given time including, but not limited to, energy efficiency (EE), conservation voltage reduction (CVR), and demand response (DR). This chapter provides current information on the status of EE, CVR, and various DR efforts.

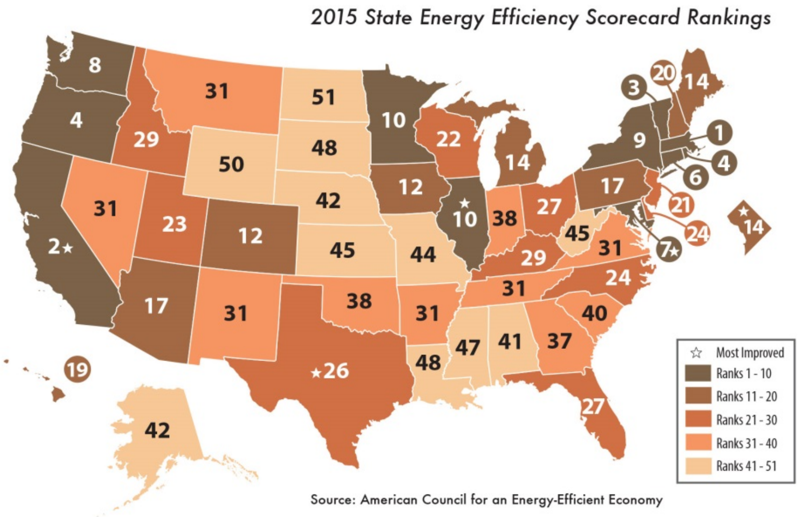
Chapter Highlights

- ★ **PGE's proactive collaboration with the Energy Trust of Oregon to acquire all cost-effective EE over the planning horizon.**
- ★ **PGE continues to work towards strategic deployment of a system-wide dynamic CVR program, following the successful completion of proof of concept.**
- ★ **PGE's 2015 potential study identifies the maximum forecast achievable demand reductions by 2021 and 2035, which PGE will pursue in a cost-effective manner.**
- ★ **PGE continues to evaluate current DR programs and is developing new pilots to serve as demand-side capacity resources.**
- ★ **PGE is conducting electric vehicle smart charging and demand response feasibility demonstrations.**

6.1 Energy Efficiency

Oregon ranks fourth among all states in EE, according to the American Council for an Energy Efficient Economy's (ACEEE) 2015 State Energy Efficiency Scorecard[117] , and has consistently ranked in the top five for the past nine years.

FIGURE 6-1: ACEEE 2015 state energy efficiency rankings



2015 State Energy Efficiency Scorecard Rankings

Source: American Council for an Energy-Efficient Economy

Since 2002, the Energy Trust of Oregon (Energy Trust) has been the independent, non-profit organization in charge of identifying the State's EE potential. PGE maintains a long-term, productive relationship with the Energy Trust to ensure that EE remains a top priority resource for the Company and the State. As a result of these collaborative efforts, Oregon has seen a significant increase in efficient use of residential electrical energy.

By way of two legislative acts, PGE collects funds from customers and passes them through to the Energy Trust, which then allocates the funds to energy efficiency projects.

First, Oregon Senate Bill (SB) 1149,[118] enacted in 1999, instituted a three percent public purpose charge (PPC) on residential electricity customers to collect funds associated with activities mandated for the benefit of the general public for a period of 10 years. These activities include energy conservation, market transformation, new renewable energy resources, and low-income weatherization. The legislation consolidated funding for EE at the state level by directing a portion of the funds collected from utility customers to several agencies charged with responsibility for running EE programs, primarily the Energy Trust. Of the total PPC, the bill directs approximately 78.4 percent towards EE activities.

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[117] ACEEE's State Energy Efficiency Scorecard, available at http://database.aceee.org/state-scorecard-rank, retrieved on June 20, 2016.

[118] A full copy of SB 1149 is available at http://energytrust.org/About/PDF/sb1149.pdf, retrieved on July 6, 2016.

Second, in 2007, the Oregon legislature enacted Senate Bill 838 (Oregon's Renewable Energy Act[119]), which extended the collection period for PPC funds until January 1, 2026. SB 838 allows PGE to set aside additional funds to invest in EE when doing so is more cost-effective than the avoided cost of supply-side alternatives for customers.[120] With these funds, PGE is able to support the Energy Trust's efforts to capture all the cost-effective energy efficiency projects identified during the IRP process.

Additionally, PGE actively:

- Markets Energy Trust programs to its customers to meet the EE deployment targets established by the Energy Trust.
- Supports customer participation in the Energy Trust programs with dedicated small commercial energy efficiency outreach specialist positions on its staff.
- Employs a technical heat pump specialist,[121] who works with Energy Trust program managers and trade allies to improve heat pump installation practices and promotes the installation of high-efficiency heat pumps.

Also, when shared technologies and programs are mutually beneficial, PGE coordinates its DR program activities with the Energy Trust's EE programs. For example, smart thermostats, used by PGE for a DR pilot, also provide EE savings, which the Energy Trust includes in its energy savings calculation.

The shared goal of the Energy Trust and PGE is to provide sufficient funding to acquire all available cost-effective EE within PGE's service area.[122] The cost-effective limit enables consideration of all measures that are equal to or less than the avoided cost of electric generation resources, with appropriate adjustments to reflect the additional value associated with the capacity and risk mitigation benefits of EE. Specifically, EE is credited to account for a reduction of peak demand associated with lower overall energy us. EE is also credited for lowering PGE's portfolio exposure to high power cost futures.

6.1.1 Energy Trust Energy Efficiency Targets

For this IRP, the Energy Trust developed two different projections: Cost-Effective EE and All Achievable EE.

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[119] A full copy of SB 838 is available on the Oregon Legislative Information Site (OLIS) at https://olis.leg.state.or.us/liz/2007R1/Downloads/MeasureDocument/SB0838/Enrolled, retrieved on July 6, 2016.

[120] Through SB 838, PGE began collecting an additional 1.25 percent in public purpose charges, in June 2008, to help acquire additional cost-effective EE. Due to existing cost-effective EE opportunities, the funding level has since increased. The projected amount in 2016 is approximately $43 million or about 3.0 percent for applicable customers.

[121] SB 838 funding covers the costs for this position.

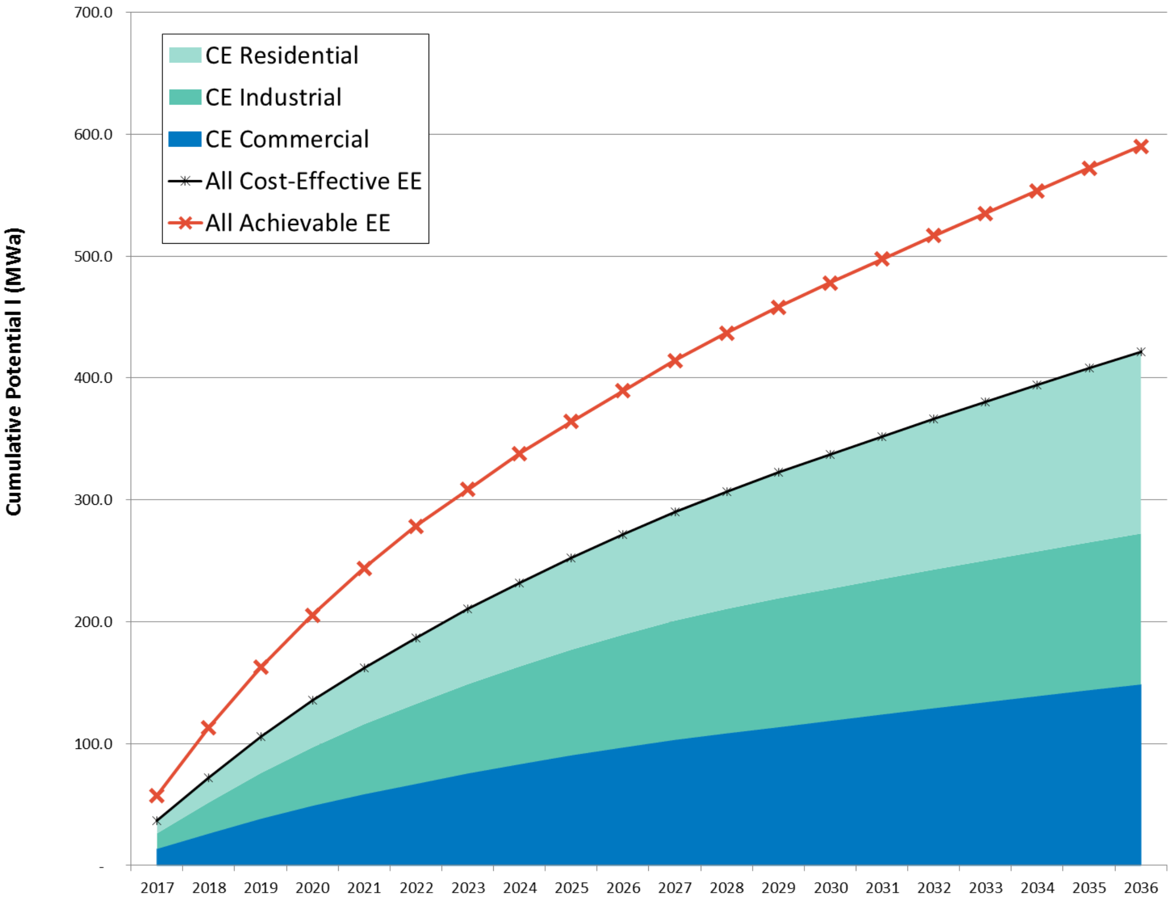
[122] See also, Oregon Senate Bill 1547, signed in to law on March 8, 2016 (requiring utilities to "plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible."), available at https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled, retrieved on July 6, 2016.

Cost-Effective EE is the amount the Energy Trust expects to acquire in the next 20 years. The Cost-Effective EE projection eliminates all measures that do not pass the Total Resource Cost (TRC) test.[123] The Cost-Effective EE forecast is the expected case EE resource for PGE. The Energy Trust forecasts total cumulative cost-effective EE by 2036 to be 421.4 MWa (gross at the busbar).

All Achievable EE includes all measures that do not have market barriers and are technically feasible. The All Achievable EE projection includes measures that may or may not be cost-effective, and measures all the EE that PGE could acquire in the next 20 years, regardless of any economic or cost-effectiveness screening. Total accumulated All Achievable EE rises to 590 MWa by 2036. Pursuit of this higher EE acquisition level would also require an increase in funding.

Figure 6-2 shows the Energy Trust's All Achievable and Cost-Effective EE projections.

FIGURE 6-2: 20-year cost-effective and all achievable EE deployment



PGE worked closely with the Energy Trust planners to develop the EE forecast. Specifically, PGE provided information to the Energy Trust, which included load growth assumptions based on PGE's

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[123] "The Total Resource Cost test should be used to determine program and measure conservation cost effectiveness. The TRC of a measure or program is the present value of retail revenue requirements plus the participant's cost for the measure(s), including operating costs, less quantified non-energy benefits and cost savings. TRC includes avoidable administrative cost." Re Calculation & Use of Cost-Effectiveness Levels for Conservation, 152 P.U.R.4th 58 (Apr. 6, 1994).

load forecast as of February 2015, cost of capital, and avoided cost inputs.[124] The Energy Trust's process to develop a PGE-specific EE estimate includes:

1. **Estimating the known technical potential EE for PGE.** Technical potential considers all EE, including resources limited by market barriers and resources that are not cost-effective. The Energy Trust used a conservation potential assessments model developed by Navigant Consulting for this step (and for steps 2-3 below).
2. **Identifying the achievable potential for all EE measures to be implemented in PGE's service territory.** Achievable potential includes all measures that do not have market barriers and are technically feasible. Achievable measures may or may not be cost-effective. The Energy Trust assumes that 85 percent of technical potential is achievable and the remaining 15 percent is not achievable due to insurmountable market barriers.[125]
3. **Screening the achievable potential for cost-effectiveness using the TRC test.** This ranks EE measures by comparing the net present value of the benefits of EE with the total costs. Benefits include:
    a. Annual kWh savings multiplied by the avoided cost; and,
    b. Quantifiable non-energy benefits, such as reduced water usage from low-flow showerheads.
4. **Developing the achievable EE resource supply curve and selecting those measures whose cost is lower than the cost-effective threshold.** The Energy Trust calculates a cost-effective threshold for PGE's service territory based on PGE's avoided cost information. For this EE forecast, the cost-effective threshold is $0.053/kWh (2016$). Figure 6-3 shows the quantity of the achievable potential that is below avoided cost and is therefore included in the Cost-Effective EE deployment forecast.

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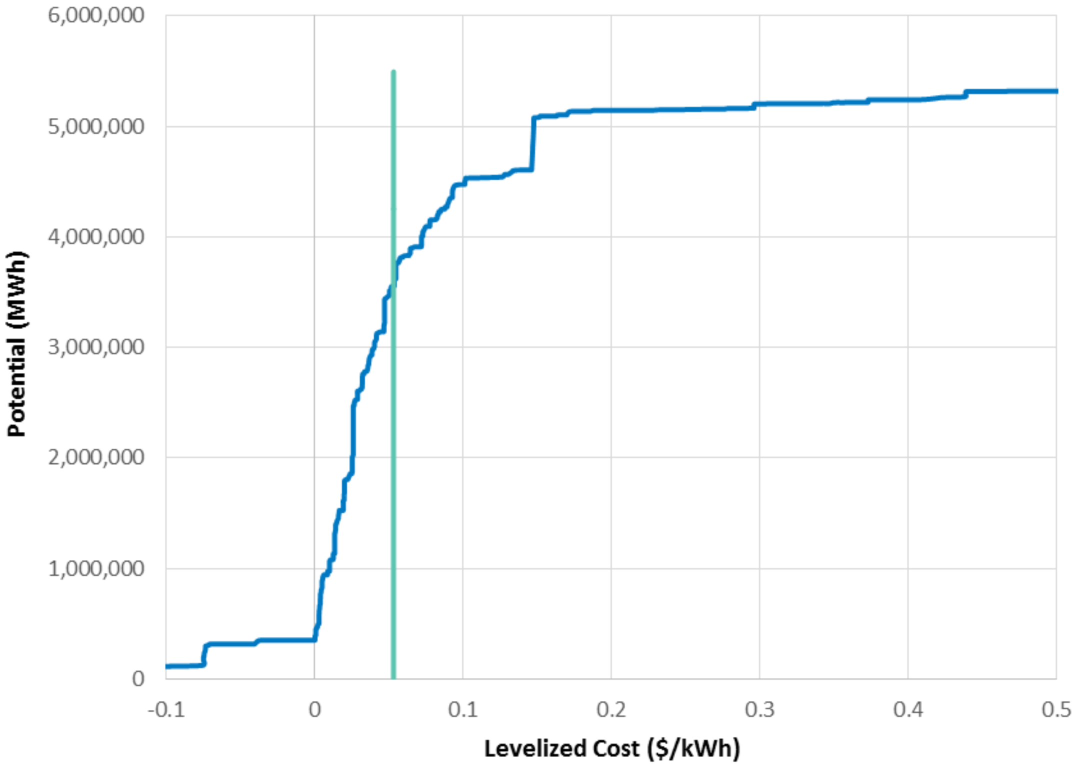
[124] EE cost effectiveness price includes avoided capacity beginning in 2021.

[125] This is a standard assumption also used by the Northwest Power and Conservation Council.

FIGURE 6-3: 20-year cost-effective and all achievable EE including costs



Source: PGE's 2016 IRP Public Meeting #2 (July 16, 2015), Energy Trust of Oregon Energy Efficiency Presentation, slide 35.

6.1.2 Energy Efficiency Growth and Future Availability

Cost-Effective EE is the preferred and lowest cost resource identified in PGE's IRP, but its availability is constrained by several factors. Below are a few examples that help explain why the potential EE supply curve in Figure 6-2 is declining.

EE projections do not include new, and yet unplanned, industrial mega-projects.[126] Mega-projects would result in higher achievable EE potential, but the Energy Trust does not forecast these projects due to the difficulty in predicting their occurrence. Likewise, the given the uncertainty regarding future technology, the Energy Trust discounts the savings attributable to developing technologies that have not yet reached commercial maturity.

6.1.3 Summary and Incorporation into 2016 IRP

In Order No. 14-415, the Commission revised and acknowledged PGE's 2013 IRP Action item for EE, directing the Company to acquire "114 MWa of cost-effective Energy Efficiency (EE) by 2017, with a target increase to 124 MWa in the event that statutory cost limitations are relieved through legislative, or other appropriate regulatory action." To date, PGE has not reached the statutory cost limitations,

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[126] Mega-projects are projects in which the customer incentive is greater than $500,000.

and may not reach the limitations in 2016. Based on recent actuals and forecasts provided by the Energy Trust, the forecast net EE acquisition from 2014 through 2017 is approximately 130 MWa.

In this IRP, PGE uses Figure 6-2's resulting estimate of 421.4 MWa by 2036 as the reference case assumption for its analysis. The Company's 2016 IRP modeling includes a portfolio which procures All Achievable EE to compare its cost and risk performance to the reference EE deployment. PGE computed costs by using the total resource cost (TRC) estimate provided by the Energy Trust. Table 6-1 shows the detailed annual EE procurement TRC for the two EE deployment cases modeled: reference and All Achievable EE.

TABLE 6-1: Energy efficiency projections

Year	All Achievable EE		Cost-Effective EE	
	MWa by Year End	Total Resource Cost (2016 k$)	MWa by Year End	Total Resource Cost (2016 k$)
2017	57.5	$545,535	36.6	$66,889
2018	55.6	$504,636	35.5	$59,953
2019	49.6	$451,951	33.6	$61,414
2020	42.6	$378,397	29.5	$55,003
2021	38.5	$329,288	27.1	$52,313
2022	34.5	$286,394	24.4	$49,025
2023	30.4	$254,667	23.5	$49,114
2024	29.4	$239,469	21.5	$45,441
2025	26.3	$227,774	20.8	$43,822
2026	25.1	$201,912	19.3	$40,128
2027	24.8	$198,211	18.4	$37,544
2028	22.5	$171,500	16.3	$33,194
2029	21.4	$164,924	15.8	$35,682
2030	19.9	$145,360	14.6	$23,723
2031	19.3	$139,055	14.8	$26,258
2032	19.4	$139,652	14.4	$25,870
2033	18.3	$135,111	14.0	$25,252
2034	18.6	$136,123	13.9	$25,258
2035	18.4	$135,758	13.8	$25,537
2036	18.1	$125,545	13.5	$24,918
Total 2017-2036	590.0	$4,911,262	421.4	$806,338

Notes: MWa at busbar, before losses

The portfolio with All Achievable EE has an additional 169 MWa savings from the reference case and investments are significantly higher. In order to capture all the achievable savings, the Energy Trust would have to pursue emerging technologies that are difficult to estimate and materially more costly than traditional, well-known, and marketed technologies.

6.2 Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) is a means of lowering consumer power demand by operating distribution feeders within the lower portion of the acceptable voltage bandwidth[127] set by the American National Standards Institute (ANSI). (See Figure 6-4.)

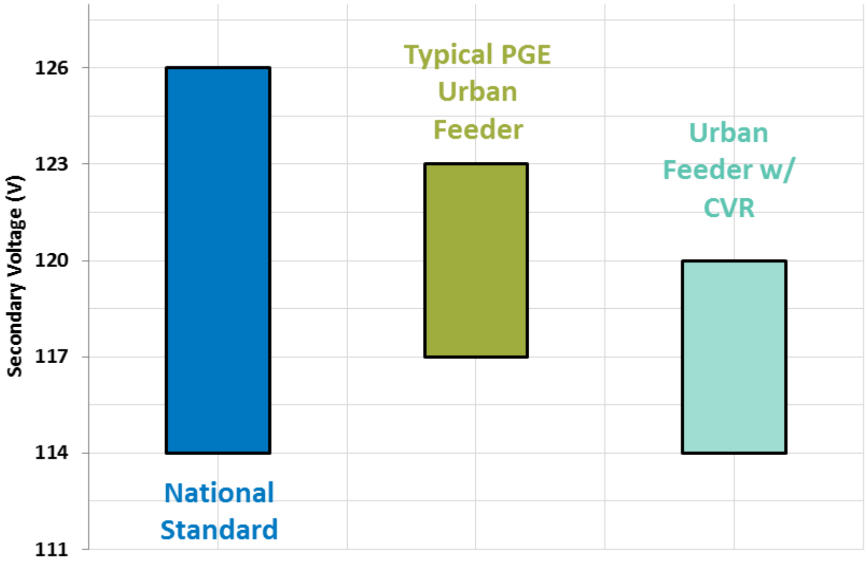
In a multi-year, phased project, the Northwest Energy Efficiency Alliance's (NEEA) Utility Distribution System Efficiency Initiative Project found that operating in the lower ANSI bandwidth should reduce customers' energy consumption.

PGE's 2013 IRP provided initial results from its 2012 CVR feasibility study. Preliminary study results indicated that peak load reductions were possible, particularly in the winter. As a result, PGE implemented a pilot project at two substations within its service territory. In the 2016 IRP, PGE uses the results from the pilot project to assess the potential net benefit of system-wide implementation of CVR, including:

1. Cost estimates for equipment needed to implement CVR.
2. Benefits in avoided kilowatt hours and reduced kilowatts of peak demand.
3. Cost/benefit economic analysis needed to move from technical potential to cost-effective potential.

As directed by the Commission in Order No. 14-415, PGE includes CVR in its 2016 IRP portfolio analysis, as discussed in Chapter 10, Modeling Methodology.

FIGURE 6-4: Service voltage for typical urban feeder with and without CVR



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[127] ANSI Standard C84.1-1989 establishes a "Range A" operating secondary voltage of +/-5 percent of the voltage base (114V – 126V).

6.2.1 Feasibility Study and Pilot Project

In 2012, PGE conducted a feasibility study to determine the viability of implementing a CVR program without incurring power quality issues (e.g., reducing a customer's voltage below the lower limit of the acceptable voltage bandwidth). PGE also performed the study in order to quantify the relationship between operating voltage and power demand on PGE's distribution system. The Company considered the following within the context of the feasibility study:

- **Selection of the substations,** Denny and Hogan South, which are representative of PGE's urban substations serving primarily residential loads.
- **Use of third-party power flow modeling software,** known as CYMDIST, for the evaluation of power flows under four load profiles: Heavy Winter (i.e., the single highest winter load hour), Light Winter (i.e., the average on-peak winter hour), Heavy Summer, and Light Summer.
- **Customer composition** (i.e., commercial, industrial, and residential) served by those substations.
- **Load characteristics** (i.e., constant impedance, constant power, and constant current) served by those substations.
- **Evaluation of system changes** necessary to implement CVR.

PGE's simulation results confirmed the conclusion made by NEEA that CVR implementation will reduce demand by lowering the amount of energy a customer consumes.

The simulation results led to the funding and implementation of the CVR pilot project at two substations within PGE's service territory: one distribution power transformer in the City of Gresham (Hogan South WR4) and one distribution power transformer in the City of Beaverton (Denny WR2). PGE implemented CVR by energizing the Hogan South substation in Gresham in July 2013; and the Denny substation in Beaverton in December 2013. The results of the pilot study validated the conclusions reached based on the feasibility study simulations. Namely, at qualified locations, CVR implementation will result in a reduction of customers' energy consumption.

The physical implementation of CVR included three operational functions:

1. Day-on/Day-off operation to provide a data comparison between "normal" mode and "CVR" mode.[128]
2. Auto/Manual control for use during contingencies and peak shaving.
3. Hourly voltage data monitoring at a limited number of targeted residential customer meters to ensure acceptable voltage levels.

Table 6-2 shows the results of physical CVR implementation in Gresham and Beaverton.

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[128] While PGE cycled CVR on and off during the pilot, when deployed at scale, CVR will always be "on."

TABLE 6-2: CVR pilot project customer energy reduction

	Hogan South WR4		Denny WR2	
Season	% kWh : 1% V[1]	Total % kWh[2]	% kWh : 1% V[1]	Total % kWh[2]
Winter	0.87 : 1	2.17%	0.99 : 1	2.47%
Summer	0.91 : 1	1.37%	0.94 : 1	1.41%

[1] Corresponds to percentage of kilowatt-hour reduction per one percent voltage reduction.

[2] Corresponds to total percentage of kilowatt-hour reduction.

Measured quantities confirmed that CVR implementation directly reduced customer demand and energy consumption. CVR is more beneficial in the winter due to the higher proportion of resistive loads (e.g., electric furnaces) relative to summer load composition; however, year-round benefits are achievable.

6.2.2 CVR Cost-Benefit Analysis

The cost-benefit analysis described in this section relies on data from the completed pilot project study. The results relate to data from only two of PGE’s substations; therefore, the Company cannot immediately extrapolate the data to its total system. PGE believes the analysis should provide useful guidance as to the relative magnitudes of the costs and benefits of CVR on the Company's system.

CVR programs act as a system-level efficiency resource, allowing customers to receive the same level of service while consuming less energy. For this reason, PGE performed the cost-benefit analysis from a total resource cost (TRC) perspective, consistent with how the Company evaluates other demand-side resources (such as EE and DR). The analysis considered all direct and quantifiable resource costs and benefits to PGE and its customers.

Because the utility makes the CVR investments, the analysis expresses costs as revenue requirements. The benefits consist of energy savings valued at their avoided costs. The avoided costs are the estimated value of the energy savings at the wholesale market level. PGE expresses the results of the analysis as the net present value of revenue requirements (NPVRR).

Table 6-3 summarizes the results of the cost-benefit analysis. Implicitly, the “Net Present Value” (NPV) assumes the completion of the two “smart grid initiatives” described in the subsequent section, which PGE will need to complete prior to converting CVR to a system-wide, dynamic program. Program benefits are the realized energy savings multiplied by the corresponding per-unit avoided costs. The table reports NPV and the benefit-cost ratio. Table 6-3 also shows that the present value of benefits exceeds the present value of costs by $1,859,073 with a benefit-cost ratio of 3.77.

TABLE 6-3: CVR net present value for the two pilot program substations

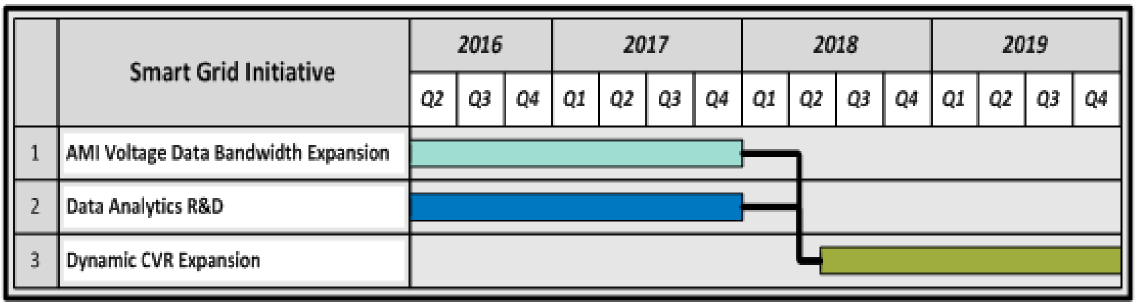
Present Value of System Benefits	$2,530,945
Present Value of Costs	$671,872
Net Present Value[1]	$1,859,073
Benefit Cost Ratio	3.77

[1] PGE based the NPV analysis on a 25-year study period.

6.2.3 Smart Grid Initiatives with CVR Elements

Due to the manual intervention[129] required to maintain the CVR pilot project, subsequent CVR installation will be unsustainable without first implementing certain foundational initiatives. Figure 6-5 shows the timing of three elements of the Smart Grid program that PGE expects will necessarily precede system-wide CVR implementation.

FIGURE 6-5: Timing of smart grid initiatives with CVR elements



6.2.3.1 Advanced Metering Infrastructure Voltage Data Bandwidth Expansion

The Advanced Metering Infrastructure (AMI) voltage data bandwidth expansion will upgrade the Sensus Regional Network Interface (RNI) software, and upgrade customer meter encryption and firmware. These upgrades will enable PGE to retrieve customer voltage data at the meter base in 60-minute intervals. The additional customer meter voltage data, and increased customer voltage resolution, will allow PGE to utilize data analytics software to assist in continuously delivering acceptable voltage to customers.

6.2.3.2 Data Analytics Research and Development

Data analytics research and development will examine which data analytics tool(s) PGE will use to analyze data obtained as a result of several smart grid initiatives, including CVR. Establishing the usage of a proven data analytics tool will provide an interactive user interface where engineers can efficiently observe the status of CVR implementation. The analytics tool will leverage the increased customer meter information, acquired as a part of the AMI voltage data bandwidth expansion, by

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[129] Today, PGE delivers customer voltage information via a raw data spreadsheet, requiring the completion of multiple, manual steps in order to analyze the effectiveness of CVR.

providing PGE with real-time customer voltage data. The analytics tool will also evaluate the voltage data and set an alarm for those meter voltages that travel outside of the acceptable voltage bandwidth. Ultimately, this will allow PGE to fine tune CVR control settings.

6.2.3.3 Dynamic CVR Expansion

After completion of the elements described above, PGE will be able to optimally expand its dynamic CVR program. The Company will manage the CVR settings and controls locally, inside the substation control house, with centralized performance monitoring. Gaining the ability to obtain additional customer meter voltage data at a higher resolution will allow PGE to utilize data analytics software to assist in continuously delivering acceptable voltage to customers. Establishing the usage of a proven data analytics tool will provide an interactive user interface where engineers can efficiently observe the status of CVR implementation. When necessary, engineers will be able to use this tool to fine tune CVR control settings, in order to obtain the maximum CVR benefit without a reduction in service quality.

6.2.4 System-Wide Implementation

Initial screening of existing distribution power transformers identified 94 optimal candidates for CVR implementation. PGE deems these transformers to be optimal sites for CVR because the substations in which they are located already have modern communication equipment (e.g., SCADA[130]) installed. These transformers primarily serve residential and commercial load, which reduces the likelihood of customers incurring power quality issues due to the reduced voltage and the existence of industrial machinery. Successive screenings may identify additional transformers as CVR candidates.

Table 6-4 shows the estimated energy savings by month for the 94 transformers based on similar energy reduction potential at each of the candidate transformers as at the pilot transformers.

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[130] Supervisory control and acquisition data (SCADA) is the system that allows PGE to remotely monitor, gather, and control real-time data at substations.

TABLE 6-4: Estimated CVR energy savings at 94 CVR candidate transformers

Month	MWh	MWa
January	16,677	22
February	15,337	23
March	14,318	19
April	13,019	18
May	7,852	11
June	7,685	11
July	9,372	13
August	9,133	12
September	8,340	12
October	8,185	11
November	14,373	20
December	18,644	25
Total Annual	**142,934**	**16**

6.2.5 Next Steps

As noted in PGE's 2016 Annual Smart Grid Report,[131] in 2015 the Company focused on communication network pilots to determine the optimal communication spectrum to monitor switched capacitor banks and customer voltage via AMI. Once the Company finishes development of the advanced analytics described above, engineers will be able to effectively monitor the implementation of CVR and clearly observe customer-level alarms for any voltage levels outside of the ANSI lower voltage bandwidth. PGE continues to work towards beginning strategic CVR deployment in 2018.

6.3 Demand Response

Interest in DR in the Pacific Northwest has grown considerably since PGE conducted its first DR potential study in 2009.[132] The increased interest in DR is due to many factors, including:

- A need to integrate growing amounts of variable energy resources (e.g., wind and solar) into the grid;

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[131] See OPUC Docket UM 1657, Portland General Electric Company Annual Smart Grid Report, filed May 31, 2016.

[132] PGE subsequently updated the 2009 study in 2012. See The Brattle Group and Global Energy Partners, "Assessment of Demand Response Potential for PGE," prepared for PGE, March 16, 2009. Also, Ahmad Faruqui and Ryan Hledik, "An Assessment of Portland General Electric's Demand Response Potential," prepared by The Brattle Group for Portland General Electric, November 28, 2012.

- An increase in the constraints on the operation of regional hydro generation;
- A growth in summer peak demand; and
- An expected additional capacity need in the next five years.

PGE is committed to DR as part of a cost-effective, reliable, and sustainable resource portfolio. Demand response will be a critical part of PGE's resource portfolio as the Company moves to greater penetrations of renewable resources, many of which lack the dispatchability of more traditional thermal units. Accordingly, and in compliance with SB 1547[133] and Commission orders, PGE will continue to "plan for and pursue the acquisition of cost-effective demand response resources."

PGE believes DR can and should:

1. **Benefit all customers.** Demand response presents an opportunity to reward PGE customers for contributing to grid stability. As with EE, PGE believes that a program portfolio should include customers of all types (residential and business, varying income levels, etc.) to ensure greater customer participation, which will enhance system reliability for all customers' benefit.
2. **Be responsive to system needs.** All programs should fit PGE's resource need. The Company will give preference to resources it can call upon rapidly, in both summer and winter seasons, and during both morning and evening peaks.
3. **Fit customers' lifestyles.** Connected devices and the growing adoption of smart technologies provide a new form of cost-effective DR that can more seamlessly integrate into customers' routines. PGE will prioritize smart technologies that provide reliable DR with minimal impact to the customer.
4. **Realize multiple value streams.** Modern DR can now operate rapidly to address multiple use cases, similar to energy storage. Where possible, PGE will pursue DR that can provide peak shaving and meet additional needs, such as firming of renewables and frequency regulation.
5. **Be reliable and low cost.** All resources that PGE deploys are subject to rigorous evaluation and cost-effectiveness analysis to ensure, when possible, the selection of lower cost resources over more expensive resources. PGE selects resources based on the OPUC IRP principle of balancing cost and risk.

PGE continues to develop DR programs that fit these criteria. The Company is a leader on demand response in the region and nationally, as evidenced by PGE's:

- Continued advocacy and support for open standards in DR, such as the CTA-2045 standard for consumer appliances;
- Demonstration of the use of DR assets in a transactive energy context as part of the Northwest Smart Grid Demonstration Project;
- Piloting of the first winter bring-your-own-thermostat program with Nest in the winter of 2015.

PGE will continue to pursue DR programs and actions that contribute to the growing maturity of the regional DR market. PGE recognizes that work is needed to raise customer and partner awareness on the benefits and opportunities associated with DR. As awareness regarding the availability and

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[133] *See* SB 1547; *see also* Oregon Laws 2016, chapter 028, section 19.

value of DR participation grows, the Company expects steady DR program growth but at a pace more gradual than utility programs in more mature markets.

A detailed discussion of PGE's current firm and non-firm DR programs is available in Appendix I, Demand Response Programs.

6.3.1 Demand Response Potential

As a result of the growing interest from stakeholders, other regional entities commissioned several new studies to explore the potential for DR. For instance, in 2014, the Northwest Power and Conservation Council (NPCC) completed a study to assess the market for various flexible load resources.[134] In that same year, PacifiCorp completed a detailed demand-side management (DSM) potential study spanning all of its jurisdictions, with substantial attention focused on DR programs.[135] The Commission noted PacifiCorp's study for the considerable role that demand-side resources will play in future resource planning efforts. Several demonstration projects and pilot studies are now underway in the region and include the involvement of PGE, the Bonneville Power Administration (BPA), Pacific Northwest National Laboratory (PNNL), and many regional utilities.

To better inform its own DR initiatives and to establish inputs to its IRP process, PGE contracted with The Brattle Group to develop an updated DR potential study. The purpose of this study was to estimate the maximum system peak demand reduction capability that PGE could realistically achieve through the deployment of specific DR programs in its service territory under reasonable expectations about future market conditions. The study also assesses the likely cost-effectiveness of these programs.

The 2015 study includes several improvements over the prior studies commissioned by PGE, both in terms of the quality of the data relied upon and the breadth of issues addressed in the study. Specific improvements in the 2015 study include the following:

- **Updated market data.** The study updated market data to account for changes in the forecasts of the number of customers by segment, seasonal peak demand, the expected timing and cost of new capacity additions, and other key assumptions that drive estimates of DR potential and its cost-effectiveness.
- **Updated DR Assumptions.** Using information from ten regional studies conducted in the past five years, the study updated assumptions about DR participation and impacts in order to reflect emerging DR program experience in the Pacific Northwest.
- **Incorporated new pricing pilot data.** To refine potential estimates for pricing programs, the study incorporated the findings of 24 new dynamic pricing pilots, conducted both in the U.S. and internationally. This allowed the study to account for several important aspects of pricing potential, including seasonal impacts and differences in price response when utilities offer programs on an opt-in versus opt-out basis.

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[134] Northwest Power and Conservation Council, "Assessing Demand Response Program Potential for the Seventh Power Plan: Updated Final Report," prepared by Navigant, January 19, 2015, retrieved on June 20, 2016.

[135] Applied Energy Group and The Brattle Group, "PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034," prepared for PacifiCorp, January 30, 2015, available at http://www.pacificorp.com/es/dsm.html, 2015 Study Documents, Volumes 1-5, retrieved on June 20, 2016.

- **Incorporated time-varying pricing data.** To improve assumptions around participation in dynamic pricing programs, the study incorporated data from a survey of market research studies and full-scale time-varying pricing deployments.
- **Improved cost-effectiveness methodology.** Based upon prior comments from the OPUC regarding the derating of avoided costs to account for the operational constraints of DR programs, the 2015 study improved PGE's methodology for estimating the cost-effectiveness of DR programs. The updated study also refined the accounting for incentive payments on the cost-side of the analysis.
- **Expanded program options.** The study significantly expanded the menu of program options analyzed to include several newly emerging options currently generating interest among utilities around the country, such as smart water heating load control, behavioral DR, electric vehicle charging load control, and "bring-your-own-thermostat" (BYOT) programs.

6.3.1.1 Methodology

PGE's 2015 potential study focuses on estimating "maximum achievable potential." A DR program's maximum achievable potential assumes achievement of enrollment rates equal to the levels attained in operational DR programs currently offered around the country. While studies demonstrate that the assumed enrollment levels are achievable by other utilities, they represent an approximate upper-bound based on some of the highest enrollment levels observed in DR programs to-date.

Most utilities estimate DR potential using empirically-based assumptions about the eligible customer base, participation, and per-customer impacts. Table 6-5 shows the fundamental equation for calculating the potential system impact of a given DR option. PGE provided Brattle with the market characteristics (e.g., system peak demand forecast, customer load profiles, number of customers in each class, appliance saturations).

TABLE 6-5: DR potential estimation framework

Potential DR Impact	=	Total Demand of Customer Base	x	% of Base Eligible to Participate	x	% of Eligible Customers Participating	x	% Reduction in Demand per Participant

6.3.1.2 Findings

The result of the analysis is an estimate of the maximum achievable peak reduction capability of each DR program for each year from 2016 through 2035, as well as a benefit-cost ratio for each program.[136] The results demonstrate 10 key findings:

1. The largest and most cost-effective DR opportunities are in the residential and large commercial and industrial customer segments.
2. Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment.

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[136] See Demand Response Study Results, available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/demand-response-study-results.xlsx?la=en, retrieved on June 20, 2016.

3. The incremental benefits of coupling enabling technology with pricing options are modest from a maximum achievable potential perspective and perhaps best realized through a BYOT program.
4. BYOT programs offer better economics than conventional direct load control (DLC) programs, but lower potential in the short- to medium-term.
5. Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits.
6. EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand.
7. Small commercial and industrial DLC has a small amount of cost-effective potential.
8. DR is highly cost-effective for large and medium commercial and industrial (C&I) customers, making it possible to realize the potential through a number of programs.
9. Agricultural DR opportunities are small and uneconomic.
10. The economics of some programs improve when accounting for their ability to provide ancillary services.

Table 6-6 shows maximum achievable demand reductions for 2021 and 2035, if PGE were to:

1. Implement each program at the start of 2016.
2. Achieve the maximum expected participation.
3. Run each program in isolation.

TABLE 6-6: Maximum achievable potential results (MW)

Class	Program	Opt-Out				Opt-In			
		Summer		Winter		Summer		Winter	
		2021	2035	2021	2035	2021	2035	2021	2035
Residential	AC DLC	N/A	N/A	N/A	N/A	106.5	144.3	0.0	0.0
Residential	Space Heating DLC	N/A	N/A	N/A	N/A	0.0	0.0	20.1	23.3
Residential	Water Heating DLC	N/A	N/A	N/A	N/A	31.0	35.2	61.9	70.4
Residential	AC/Space Heating DLC	N/A	N/A	N/A	N/A	12.3	14.3	15.4	17.9
Residential	TOU	42.0	45.7	61.7	65.2	22.7	25.3	33.0	35.6
Residential	PTR	94.3	102.9	136.2	144.1	42.6	47.3	61.0	65.8
Residential	PTR w/Tech	23.5	25.7	24.6	26.0	12.9	14.3	13.4	14.5
Residential	CPP	76.2	82.9	109.4	115.5	31.9	35.5	45.4	49.0
Residential	CPP w/Tech	20.4	22.2	21.2	22.4	9.6	10.7	10.0	10.8
Residential	Behavioral DR	38.1	41.7	54.6	57.9	9.5	10.4	13.6	14.5
Residential	BYOT – AC	N/A	N/A	N/A	N/A	42.1	49.0	0.0	0.0
Residential	BYOT - Space Heating	N/A	N/A	N/A	N/A	0.0	0.0	12.6	14.6
Residential	BYOT - AC/Space Heating	N/A	N/A	N/A	N/A	7.7	8.9	9.6	11.2
Residential	Smart Water Heater DLC	N/A	N/A	N/A	N/A	7.6	44.5	15.1	88.9
Residential	Electric Vehicle DLC	N/A	N/A	N/A	N/A	0.5	2.5	0.3	1.8
Small C&I	AC DLC	N/A	N/A	N/A	N/A	12.8	15.9	0.0	0.0
Small C&I	Space Heating DLC	N/A	N/A	N/A	N/A	0.0	0.0	6.0	7.5
Small C&I	Water Heating DLC	N/A	N/A	N/A	N/A	0.7	0.8	1.3	1.6
Small C&I	AC/Space Heating DLC	N/A	N/A	N/A	N/A	3.4	4.2	4.3	5.3
Small C&I	TOU	0.5	0.6	0.5	0.6	0.1	0.1	0.1	0.1
Small C&I	PTR	1.7	2.1	1.7	2.0	0.5	0.6	0.5	0.6
Small C&I	PTR w/Tech	3.7	4.6	2.7	3.3	1.2	1.6	0.9	1.1
Small C&I	CPP	0.9	1.1	0.8	1.0	0.2	0.3	0.3	0.4
Small C&I	CPP w/Tech	2.2	2.6	1.6	1.9	0.6	0.8	0.4	0.6
Medium C&I	Third-Party DLC	N/A	N/A	N/A	N/A	46.1	57.1	38.1	46.8
Medium C&I	Curtailable Tariff	N/A	N/A	N/A	N/A	24.6	30.4	20.3	25.0
Medium C&I	CPP	21.9	26.8	18.1	22.0	6.1	7.7	5.0	6.3
Medium C&I	CPP w/Tech	38.5	47.3	31.8	38.8	10.9	13.7	9.0	11.2
Large C&I	Third-Party DLC	N/A	N/A	N/A	N/A	62.8	80.7	54.3	69.2
Large C&I	Curtailable Tariff	N/A	N/A	N/A	N/A	80.4	103.3	69.5	88.6
Large C&I	CPP	40.9	52.1	35.4	44.7	11.4	14.9	9.8	12.8
Large C&I	CPP w/Tech	83.9	106.9	72.5	91.7	29.6	38.7	25.6	33.2
Agricultural	Pumping Load Control	N/A	N/A	N/A	N/A	3.8	2.9	0.0	0.0
Agricultural	TOU	1.7	1.3	0.0	0.0	0.3	0.2	0.0	0.0

Table 6-7 shows the cost-effectiveness of each program from a TRC perspective. The numbers in red are programs that are not cost-effective. Note that nearly all programs are cost-effective save those in the small C&I sector. PGE believes cost reductions for these programs are possible, if coupled with either a residential or medium/large C&I offering.

TABLE 6-7: Demand response potential study TRC benefit-cost ratios

Class	Program	B/C Ratio		Class	Program	B/C Ratio	
		Opt-Out	Opt-In			Opt-Out	Opt-In
Residential	AC DLC	N/A	1.12	Small C&I	AC DLC	N/A	1.00
Residential	Space Heating DLC	N/A	1.31	Small C&I	Space Heating DLC	N/A	1.07
Residential	Water Heating DLC	N/A	1.30	Small C&I	Water Heating DLC	N/A	0.79
Residential	AC/Space Heating DLC	N/A	1.82	Small C&I	AC/Space Heating DLC	N/A	1.40
Residential	TOU	1.24	1.24	Small C&I	TOU	0.11	0.06
Residential	PTR	1.49	1.75	Small C&I	PTR	0.30	0.17
Residential	PTR w/Tech	0.86	1.32	Small C&I	PTR w/Tech	0.82	0.79
Residential	CPP	1.15	1.62	Small C&I	CPP	0.11	0.08
Residential	CPP w/Tech	0.83	1.49	Small C&I	CPP w/Tech	0.60	0.55
Residential	Behavioral DR	1.04	0.85	Medium C&I	Third-Party DLC	N/A	1.59
Residential	BYOT – AC	N/A	1.94	Medium C&I	Curtailable Tariff	N/A	5.37
Residential	BYOT - Space Heating	N/A	1.98	Medium C&I	CPP	4.80	1.94
Residential	BYOT - AC/Space Heating	N/A	2.43	Medium C&I	CPP w/Tech	1.76	1.38
Residential	Smart Water Heater DLC	N/A	2.99	Large C&I	Third-Party DLC	N/A	1.57
Residential	Electric Vehicle DLC	N/A	0.16	Large C&I	Curtailable Tariff	N/A	6.30
				Large C&I	CPP	42.10	14.42
				Large C&I	CPP w/Tech	7.15	6.70
				Agricultural	Pumping Load Control	N/A	0.78
				Agricultural	TOU	0.83	0.29

6.3.1.3 Recommendations

The findings of the study suggest several considerations for future DR offerings by PGE:

- Run a new dynamic pricing and behavioral DR pilot;
- Develop a water heating load control program;
- Continue to pursue opportunities in the large and medium C&I sectors;
- Establish well-defined cost-effectiveness protocols;
- Develop a long-term rates strategy enabled by PGE's AMI investment; and
- Explore the distribution system value of DR.

PGE is acting on all of the recommendations from this study as follows:

1. PGE's residential pricing pilot commenced in June 2016 and will end in February 2018.
2. PGE will develop a mass-market water heater program in late 2016 with a goal of deploying in 2017.
3. PGE is looking to expand its offerings to medium C&I customers in 2017.
4. PGE proposed a standardized approach to evaluating the cost-effectiveness of DR programs.

5. PGE will implement a full-scale dynamic pricing program following the pilot and completion of PGE's Customer Engagement Transformation program (CET).
6. PGE is currently exploring distribution value through collaboration on smart grid initiatives, including the Transmission and Distribution (T&D) analytics pilot.

6.3.1.4 Incorporation into IRP

Using the values from the DR potential study as a starting point, PGE developed portfolios of DR programs for consideration over the planning horizon. To account for uncertainty and provide bounds for the potential resource, PGE developed three potential DR portfolios: low, reference, and high. The Company constructed each DR portfolio from the set of programs that presented high demand potential, were likely to be cost-effective, and were consistent with lessons learned from previous pilots.

Table 6-8 shows the programs included in each portfolio and the following provides a description of the acronyms used in the "Delivery Type" column:

- Air Conditioning (AC)
- Bring Your Own Thermostat (BYOT)
- Direct Load Control (DLC)
- Electric Vehicle (EV)
- Peak Time Rebate (PTR)
- Water Heater (WH)
- Time of Use (TOU)

TABLE 6-8: DR portfolios considered

Portfolio	Delivery Type	Scenario		
		Low	Reference	High
Residential	AC DLC	Opt-in	Opt-in	Opt-in
Residential	AC/Space Heating DLC	Opt-in	Opt-in	Opt-in
Residential	Behavioral DR	Opt-in	Opt-in	Opt-in
Residential	BYOT - AC			
Residential	BYOT - AC/Space Heating			Opt-in
Residential	BYOT - Space Heating			Opt-in
Residential	EV DLC		Opt-out	
Residential	PTR	Opt-in	Opt-in	Opt-in
Residential	Smart WH DLC	Opt-in	Opt-in	Opt-in
Residential	Space Heating DLC	Opt-in	Opt-in	Opt-in
Residential	TOU			Opt-in
Residential	Water Heating DLC	Opt-in	Opt-in	Opt-out
Small C&I	AC DLC			Opt-in
Small C&I	AC/Space Heating DLC			Opt-in
Small C&I	PTR	Opt-in	Opt-in	Opt-out
Small C&I	Space Heating DLC	Opt-in	Opt-in	Opt-in
Small C&I	TOU	Opt-in	Opt-in	Opt-in
Small C&I	Water Heating DLC	Opt-in	Opt-in	Opt-in
Medium C&I	Curtailable Tariff	Opt-in	Opt-in	Opt-out
Medium C&I	Third-Party DLC	Opt-in	Opt-in	Opt-in
Large C&I	Curtailable Tariff			Opt-out
Large C&I	Third-Party DLC	Opt-in	Opt-in	Opt-in

PGE also modified results from the potential study to account for various factors:

Allow for pilot periods

Unlike in the potential study where programs start at mass scale, PGE's planning numbers assume that there will be a pilot period for each program. These are typically two years long, consistent with past pilots.

Interactions between programs

The potential study looked at each program option in isolation and did not account for potential interactions between programs. For instance, a customer participating in a TOU rate would presumably have less demand on peak to offer when participating in a DLC program. PGE used the interaction rules provided in Table 6-9 to adjust the potential demand when certain combinations of programs are present in a portfolio:

TABLE 6-9: Interactive effects adjustments

Interaction Rule*	Factor
Retrofit DLC programs have comparable new "smart" units subtracted from potential	100%
Individual AC and space heat have combined AC/SH subtracted from them	100%
Subtract portion of TOU impacts from PTR	50%
Subtract portion of Curtailable tariff impacts from ADR	50%
Subtract portion of PTR impacts from BDR	50%
Subtract portion of DLC if opt-in pricing present	25%
Subtract portion of DLC if opt-out pricing present	50%

*For example, for the interaction between TOU and PTR, the total expected TOU impact reduces the total expected impact of PTR programs by 50%. This accounts for reductions in the marginal impact of PTR programs after implementation of TOU rates.

Pragmatic participation/maturation rates

The potential study estimated the maximum achievable potential, not necessarily the expected participation. For this reason, as shown in Table 6-10, PGE adjusted the assumed participation rates. The study also assumed a uniform five years to maturation for all programs. Based on PGE's experience with pilots and the relative low level of awareness around DR in the region, the Company extended that timeline, particularly for nonresidential customers.

TABLE 6-10: Participation and maturation rate adjustments

Sector	Portfolio	Participation Adjustment Factor	Time to Saturation
Residential	Low	50%	7
Residential	Reference	65%	5
Residential	High	75%	5
Nonresidential	Low	40%	10
Nonresidential	Reference	50%	10
Nonresidential	High	65%	5

Timing aligned with other initiatives

Where full scale programs would rely heavily on either PGE's customer information system or meter data management system, the Company delayed full scale implementation until after the completion of these system replacements (as part of the CET program) in 2018. To account for any potential delays, PGE set the target start dates for these programs to 2020.

Evaluation requirements

In the case of opt-out programs, such as behavioral demand response, PGE assumed that it would need to hold out some portion of the program population for an evaluation period. In these cases, the Company assumed that it would withhold 25 percent of the eligible population from the program for the first two years.

Combining these adjustments gives the Company the projected DR potential for each portfolio. Table 6-11 presents these projections for each season in both 2021 and 2035.

TABLE 6-11: Targeted demand reduction by season and scenario

	2021		2035	
Portfolio	**Summer MW**	**Winter MW**	**Summer MW**	**Winter MW**
Low	40	36	136	145
Reference	74	78	182	197
High	162	191	258	296

PGE used the values for the reference scenario in its resource portfolio analysis for the IRP.

6.3.2 Future Demand Response Actions

The reference DR portfolio is PGE's preferred resource plan for DR as the Company believes it provides an aggressive, but attainable goal. Table 6-12 below outlines the programs included in this portfolio and their respective timelines. Appendix I, Demand Response Programs, provides a description of the various DR programs. PGE will continue to engage OPUC Staff, stakeholders, and customers on how best to design, implement, and monitor the success of these programs.

TABLE 6-12: Demand response program timeline

Class	Program	Pilot Start	Pilot End	Program Start
Residential	Behavioral DR	2016	2018	2020
Residential	Water Heating DLC	2017	2019	2020
Residential	TOU	2016	2018	2020
Residential	PTR	2016	2018	2020
Residential	Bring Your Own Thermostat	2016	2017	2018
Residential	EV DLC	2017	2019	TBD
Residential	Smart WH DLC	2017	2019	TBD
Small C&I	HVAC DLC	2018	2020	2020
Small C&I	Water Heating DLC	2018	2020	2020
Small C&I	PTR	2018	2020	2020
Medium C&I	Third-Party DLC	2017	2019	2020
Medium C&I	Curtailable Tariff	2018	2020	2020
Large C&I	Third-Party DLC	2013	2017	2018
Large C&I	Curtailable Tariff	2018	2020	2020

6.3.3 Additional Demand Response Issues

6.3.3.1 Resource Cost-Effectiveness

As of March 2016, PGE is running multiple pilots of new DR programs, creating the need for a DR cost-effectiveness methodology. Cost-effectiveness is a necessary metric to help PGE, the OPUC, and stakeholders evaluate DR programs. Moreover, because DR has the potential to meet various capacity needs, the cost-effectiveness methodology applied to DR programs must be able to capture the unique costs and benefits of DR. In light of the growth of DR, the OPUC, in Order No. 15-203, ordered that "PGE, the Commission and stakeholders develop a cost effectiveness methodology for demand response that is particular to the capabilities and products of this resource."[137]

In compliance with Order No. 15-203, PGE retained Navigant to inform its determination of DR cost-effectiveness with best practices from other areas of the country, building on the initial work done by Brattle in PGE's potential study. On February 9, 2016, PGE held a workshop on DR cost-effectiveness attended by OPUC Staff and stakeholders. The resulting Navigant white paper (filed with the Commission on April 28, 2016) incorporated comments from this workshop.

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[137] Order No. 15-203, Appendix A at 13.

Navigant's white paper[138] outlines a proposed cost-effectiveness methodology for the planning and evaluation of DR programs.[139] PGE intends the Navigant report to be the starting point of an iterative process to arrive at a cost-effectiveness methodology that satisfies the needs of PGE, the OPUC, and stakeholders.[140] The cost-effectiveness framework presented in the white paper relies on California protocols[141] and other industry best practices established around the country. Navigant then adapts the framework for PGE's purposes based on stakeholder feedback. This framework also draws from current efforts underway at the Energy Trust and previous work Navigant conducted to develop a regional business case for grid modernization investments for BPA.[142]

The framework presented here is rooted in the four standard cost-effectiveness tests traditionally used in EE cost-effectiveness assessments, with DR-specific benefit and cost streams. Avoided or deferred capacity expansion is the primary quantifiable benefit of a DR program. This framework discusses two potential methods for accounting for the impact that differences in usage and availability may have on the avoided cost of capacity expansion for a DR resource versus a traditional generating resource:

- Effective Load Carrying Capability (ELCC) calculation; and
- Avoided cost adjustment factors.

This framework also addresses the treatment of typical DR-related costs, including:

- Administrative costs;
- Capital costs to the utility and participant;
- Incentives; and
- Other participant costs (with a suggested approach for incorporating the significant uncertainty associated with DR program participant costs).

Some cost and benefit streams from DR are difficult to quantify. This is due either to a lack of DR program performance data, lack of generally accepted quantification methodologies, or insufficient historical performance data for DR programs. The Navigant paper describes the cost and benefit streams qualitatively, with suggestions for future quantification methodologies where appropriate.

The white paper presents an approach for determining the cost-effectiveness of DR programs within PGE's jurisdiction. PGE applied the framework discussed within the white paper to its Energy Partner^{SM} program, which is a day-of load curtailment program targeted at commercial and industrial

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[138] Portland General Electric, A Proposed Cost-Effectiveness Approach for Demand Response, Prepared by Navigant Consulting, Inc., April 2016.

[139] PGE also notes that Section 19(2)(b) of SB 1547 requires the OPUC to direct electric companies "by rule or order, [to] plan for and pursue the acquisition of cost-effective demand response resources." *See* SB 1547; *see also* Oregon Laws 2016, chapter 028, section 19.

[140] PGE filed the Navigant white paper with the OPUC in Docket UM 1708, and incorporates the report by reference into this IRP. See "PGE's Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots," Docket UM 1708, filed April 28, 2016.

[141] California Public Utilities Commission, Attachment 1: 2010 Demand Response Cost Effectiveness Protocols.

[142] Bonneville Power Administration, Smart Grid Regional Business Case White Paper, Prepared by Navigant Consulting, Inc., September 2015.

customers. The framework will subsequently inform the cost-effectiveness analyses of PGE's other DR programs.

6.3.3.2 Energy Partner^{SM}

The Energy Partner^{SM} program continues to grow considerably; however, it still remains short of its initial target, which was a nominated demand of 25 MW by 2017. As of April 2016, the program had 11.2 MW nominated.

While some of this can be attributed to low market awareness and less discretionary load than originally anticipated, a significant driver of this shortfall is that the program administrator has almost exclusively targeted very large commercial and industrial customers (> 200 kW). Large customers on direct access are not eligible for the program and PGE has relatively few large customers with flexible loads. In fact, many of PGE's largest customers are in the high tech industry (microprocessors, data servers), with operations that have very little elasticity in their electricity demand. For this reason, PGE is planning to pursue additional contractors that can provide similar services for customers smaller than 200 kW, with the hope that expanding to this segment will help make up some of the shortfall.

6.4 Plug-in Electric Vehicles

With the growing adoption of plug-in electric vehicles (PEVs) across the country and in Oregon, PGE is interested in the opportunities that PEVs may present for active grid management.

6.4.1 PGE Actions

PGE is currently conducting feasibility demonstrations of Smart PEV charging and PEV charging demand response. These projects include:

- **Eleven Workplace Chargers**
  - PGE built an interface using a vendor supplied Application Programming Interface (API) and successfully tested demand response control capability with one of the workplace chargers.
- **Thirty-five Residential Chargers**
  - PGE is installing ten chargers with an Electric Power Research Institute (EPRI) Project using Siemens Residential Charger with interface for utility control. PGE expects to complete the installations in the fourth quarter of 2016.
  - PGE is installing twenty-five Smart Residential Chargers with Wi-Fi interface to collect detailed charging information and compare with utility interval data. Chargers work with Nest to collect usage information from the user and automatically control charge based on TOU periods. PGE has installed ten chargers, and expects to complete the additional installations by the fourth quarter of 2016.

Similar to the workplace charger Demand Response demonstration, PGE tested the capability to reduce the charging using an API from the charger manufacturer.

FIGURE 6-6: Plug-in electric car

6.4.2 Equipment and Controls

PGE will need to use multiple platforms to create a mass market program for controlling PEV charging. These methods include:

- Controlling the vehicle through telematics with the vehicle manufacturer (e.g., Onstar for GM, NissanConnect or Tesla) or using third party supplied devices connected to the car through the ODBII connector (e.g., FleetKarma).
- Controlling a Smart Breaker in the electrical panel.
- Controlling the Electric Vehicle Supply Equipment (EVSE - commonly called the EV Charger).

The **OBD-II (On-Board Diagnostics)** connector provides access to and control over vehicle engine functions and monitors numerous parts of a vehicle, making it easier to diagnose problems with the vehicle. More information is available at www.obdii.com.

Controlling PEV charging using a Smart Breaker or through the EVSE does not currently provide the capability to consider the PEV battery's state of charge, which is necessary for optimal integration. To control charging options, PGE continues to monitor grid integration projects undertaken by other parties and the Company is conducting a Vehicle to Grid (V2G) concept demonstration test.

6.4.3 Future Actions

PGE is currently engaged in developing a more comprehensive PEV strategy through OPUC Docket AR 599, a rulemaking docket opened by the Commission to prescribe application requirements for utility transportation electrification programs.[143]

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[143] The Commissioned opened AR 599 to implement the requirements of Section 20 of SB 1547, Transportation Electrification Programs. *See* SB 1547; *see also* Oregon Laws 2016, chapter 028, section 20.

While the DR Potential Study referenced in Section 6.3.1.2, Findings, above shows little potential for DR as a standalone program with EVs, we want to ensure that EV charging will support the grid rather than operate as a detriment to the grid. Smarter charging can be done through the use of many of these same controls. More research is needed in this area.

CHAPTER 7. Supply Options

This chapter provides information on a variety of electric generating, or supply resources for meeting PGE's future capacity and energy needs. PGE examines a full range of supply alternatives including renewable, thermal, and distributed generation options. For each option, PGE makes reasonable assumptions about the availability of each resource and its associated attributes. The Company explores data sources, assumptions for costs, anticipated advances in technology, and areas of uncertainty. In Chapter 12, Modeling Results, PGE presents the results of the resource modeling, which examines supply, demand, and integration resources in an integrated manner. This supply options section closes with a discussion of emerging technologies and PGE's options for obtaining new resources.

Chapter Highlights

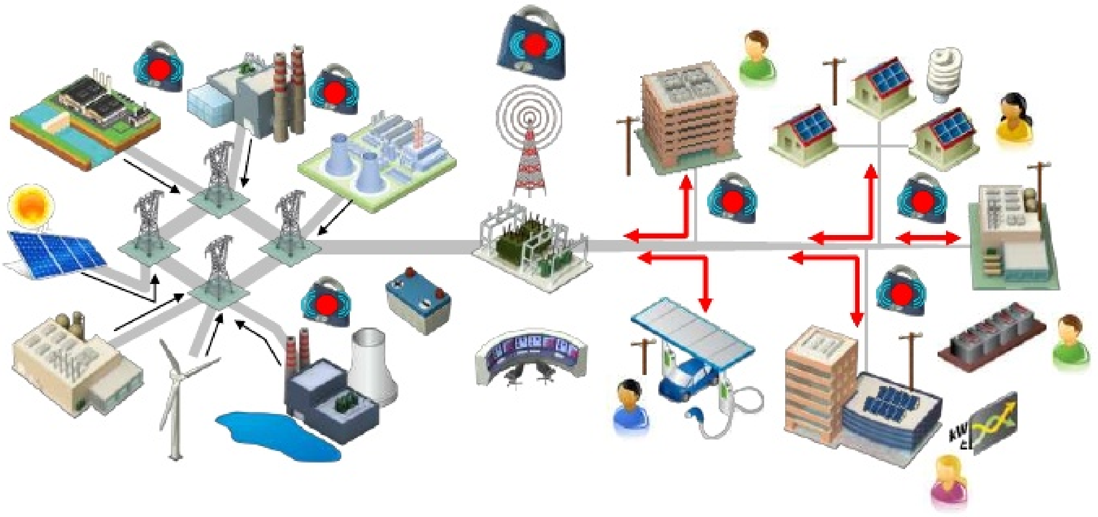
- ★ **PGE includes in its analysis those supply alternatives that are currently available or expected to become available during the Action Plan time horizon to meet the Company's resource needs.**
- ★ **PGE discloses status, developments, and studies performed for an improved understanding of the distributed generation potential in its service territory.**
- ★ **PGE describes the Reference Case capital and operating costs and underlying assumptions for all resources included in its portfolio analysis.**
- ★ **PGE considers natural gas-fired simple-cycle and combined-cycle combustion turbines, reciprocating engines, and renewables (biomass, geothermal, solar, and wind).**
- ★ **PGE updates its estimate of integration cost for renewables to $0.92 per MWh (in 2021 dollars, $0.83/MWh in 2016 dollars) from approximately $4 per MWh in the 2013 IRP.**
- ★ **PGE does not estimate incremental transmission investments required to access renewable resources in remote areas, including Montana, for lack of data. Rather, PGE uses a break-even analysis to establish a potential transmission budget.**
- ★ **PGE reviews developing technology, such as hydrokinetics, for inclusion in future IRPs.**
- ★ **PGE compares resource ownership to power purchase agreements.**

7.1 Distributed Generation

Distributed generation (DG) refers to supply resources that connect into the distribution grid rather than the bulk transmission grid, whether on the utility side or customer side of the meter. This could include a resource connecting at a distribution substation, distribution transformer, distribution feeder, or at a customer site. Distributed generation benefits to PGE and its customers may include, but are not limited to:

- Enhanced localized reliability.
- Improved efficiency due to avoided transmission losses.
- A partial hedge against changing future power costs.

FIGURE 7-1: Distributed generation conceptual model



Source: Electric Power Research Institute (EPRI) http://www.slideshare.net/webgoddesscathy/emerging-energy-generation-and-storage-technology-by-mark-tinkler

In PGE's service territory, there are currently three main DG technologies:

- Solar Photovoltaic (PV)
- Combined-heat and power (CHP)
- Dispatchable Standby Generation (DSG).

PGE models PV and DSG resources in this IRP, in conjunction with central-station generation. DSG is common to all of PGE's portfolios. PGE does not model CHP in this IRP, because it is inherently operation- and customer-specific. As directed by the Commission in Order No. 14-415, PGE evaluated studies which assessed CHP potential in Oregon.[144] The Company will further evaluate CHP in future IRPs.

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[144] See Appendix I, Demand Response Programs, "Assessment of the Technical and Economic Potential for CHP in Oregon," ICF International, July 2014.

The development of customer-sited DG on PGE's system is primarily the result of two programs, net metering, and the Oregon Volumetric Incentive Rate (a.k.a. feed-in-tariff) specifically for PV.

- **Net Metering.** Customers in PGE's net metering program use their own renewable power sources to offset part, or all, of their load. Per the tariff, the customer handles all installation arrangements and the system must meet all applicable codes. PGE provides a bi-directional meter to allow measurement of energy flowing both to and from the customer's site. PGE also conducts an inspection at the time of the net meter installation. PGE markets the program via the www.portlandgeneral.com website and various publications. Net metering customers can also receive incentives from the Energy Trust, as well as state and federal tax credits.
- **Oregon Volumetric Incentive Rate (VIR) Program.**[145] The Oregon VIR program provides customers an incentive to install a PV system of up to 500 kW on their home or business. Before installing a solar system, customers must apply for, and be awarded capacity, during an open enrollment window. The customer contracts associated with these systems have a 15-year term. PGE provides a separate meter to measure the energy produced by the customer's solar system. The program does not allow customers to combine Energy Trust or state tax incentives with the VIR incentive.

Collectively, these two programs total approximately 65 megawatts direct current (MWdc), ~48 MWdc from net-metering and ~17 MWdc from the Oregon VIR on PGE's system. Non-solar DG (low-impact hydro, small-scale wind, fuel cells, methane gas, and CHP) capacity installed on PGE's system is approximately 8 megawatts alternating current (MWac), ~4 MWac from net-metering and ~4 MWac from non-net-metered CHP. The grid-sited DG on PGE's system primarily consists of PV (~12 MWdc), developed as qualifying facilities.

7.1.1 Distributed Generation in the 2013 IRP

As part of the 2013 IRP, PGE conducted a preliminary scoping analysis to assess the technical potential for distributed PV in its service territory. The objective was to gauge whether distributed PV could cause PGE to reassess the need for (or timing of) new centralized renewable resources. The scoping analysis estimated the technical potential for distributed PV in PGE's service territory at about 1300 MWdc, equivalent to an annual average output of 155 MWa AC. At the time of the study, PGE customers were adding roughly 9 MWdc or 1 MWa AC per year of distributed PV.

Given the findings from the scoping analysis, PGE concluded that for widespread adoption of distributed PV to occur, PV pricing would need to reach parity with embedded prices. Even at a much accelerated rate of adoption, relative to the above quantity, PGE estimated the annual average load reduction would likely be gradual and modest. And thus, distributed PV adoption would not materially reduce the need for other generation resources at the time. PGE cautioned that since the capacity-to-energy ratio of distributed PV was 6-to-1, a large increase of DG PV would necessitate back-up generation to provide ancillary services.

The 2013 IRP preliminary scoping analysis encouraged PGE to plan for the following actions during the Action Plan window:

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[145] Currently, this program is not accepting new entrants.

- Pursuing pilot programs and research initiatives with the goal of assessing potential business models and policies that expand the installation of cost-effective distributed PV. These programs and policies will also seek to avoid cross-subsidies, limit lost revenue, and properly value the energy and ancillary benefits that come from distributed solar generation.
- Studying the value of solar to PGE's distribution system, implementing tariffs that appropriately share the benefits and costs of distributed solar among customers and providing direct incentives to customers through the utility for the installation of PV.
- Evaluating the installation of centralized solar, potentially via a new program that would allocate solar benefits to customers who lack the ability to site their own PV systems due to inappropriate rooftop space, non-home ownership (e.g., renters), or insufficient capital capacity.

PGE formalized the first of these actions with the commencement of enabling studies for distributed generation. For action item two, the Company is engaged in the OPUC's investigation to determine the Resource Value of Solar (Docket No. UM 1716). PGE commenced action item three, when the Company opened its Green Future Solar program for enrollment in the fall of 2015. The program allows residential and business customers to purchase solar energy from a solar project in Willamina, Oregon, in one-kW blocks. In April 2016, the program sold out and PGE is not currently accepting new enrollments.

In 2015, PGE participated in OPUC Docket No. UM 1746, which the Commission opened in compliance with HB 2941 to receive input and provide recommendations to the Oregon Legislature on designs and attributes for a community solar program. PGE plans to continue its participation in OPUC efforts regarding community solar in Docket No. AR 603, a rulemaking docket designed to implement the community solar provisions of Section 22 of SB 1547.[146]

7.1.2 Distributed Generation Enabling Studies

Consistent with the 2013 IRP Action Plan, PGE conducted studies to assess the potential of cost-effective distributed generation in its service territory and the potential of centralized solar generation in Oregon between 2015 and 2035. Black & Veatch (B&V) conducted two studies on behalf of PGE,[147] consisting of a market assessment and cost projections for PV[148] and non-solar DG,[149] respectively. At the same time, Clean Power Research (CPR) conducted a study on behalf of PGE to determine a robust methodology for valuing the costs and benefits that distributed solar brings to PGE's energy grid.[150]

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[146] Section 22 of SB 1547 allows PGE's residential and small commercial customers to buy a portion of an off-site solar project and have credits applied to their utility bills. It also directs the OPUC to ensure that at least 10% of the overall community solar program capacity be provided to low-income customers.

[147] Black and Veatch also conducted studies pertaining to resource cost and performance, which PGE discusses in later in this chapter in Section 7.4, Supply Resource Cost Summary. The later studies are unrelated to the DG studies mentioned here.

[148] See Appendix F, Distributed Generation Studies; see also https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning.

[149] Id.

[150] Id.

B&V completed its studies in September of 2015; however, subsequent changes in federal law affect some of the studies' assumptions and potentially invalidate some of the conclusions. The most notable difference is the change in the expiration date of the 30 percent federal investment tax credit (ITC), which is a major driver for the results of the solar study. When B&V performed this study, the 30 percent ITC was set to expire at the end of 2016 and fall to 10 percent thereafter. As discussed in Chapter 3, Planning Environment, on December 18, 2015, Congress passed legislation that extended the ITC as follows for commercial projects based on the year in which construction commences:

- 30 percent through 2019;
- 26 percent through 2020;
- 22 percent through 2021; and
- 10 percent thereafter.

Congress also extended the ITC for residential projects at 30 percent for systems placed in-service through 2019, after which the ITC phases out by 2022.

B&V is currently updating its solar PV study to reflect these changes, but results will not be available for the 2016 IRP. PGE plans to incorporate the results in the next IRP update or IRP. Below is a summary of the September 2015 B&V study.

7.1.2.1 Solar PV Technology

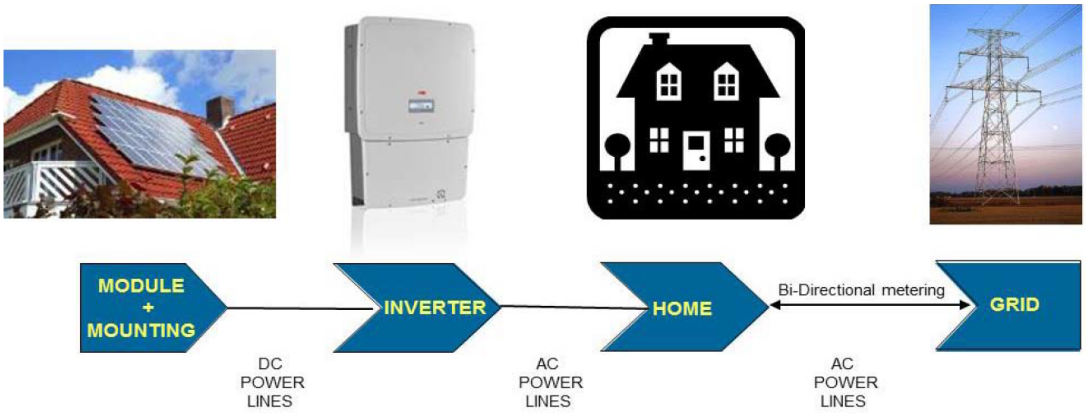
Photovoltaic systems convert sunlight directly into electricity. There are three main types of commercially available PV technologies to: monocrystalline, polycrystalline, and thin film, in order of their efficiency from highest to lowest. Less efficient technologies do not necessarily mean inferior performance; aside from some slight variations in performance curves, the main difference is that less efficient technologies require more surface area for the same amount of output. The selection of a particular module technology depends on the cost of the technology and presence of site space constraints.

Inverters convert the direct current (dc) output of solar modules to alternating current (ac), so that the electrical grid and most electrical devices can use the power. Utilities may report solar system nameplate capacity in dc or ac, representing the capacity of modules and capacity of inverters, respectively.

Racking systems refer to the support system for solar modules. There are two main types of racking systems: fixed tilt and single-axis tracking. The latter tracks the sun's movement from east to west. There are dual-axis tracking systems that track the sun's shift north to south as well, but these systems are more costly and less common in the industry. Due to the ability to track the sun, the single-axis tracking systems can produce more energy on average than fixed-tilt systems, but the tracking systems cost more. Regardless of the module technologies or racking systems selected, the levelized cost of energy (LCOE) for these various combinations requires consideration.

Figure 7-2 provides an image of the components of a distributed solar PV system.

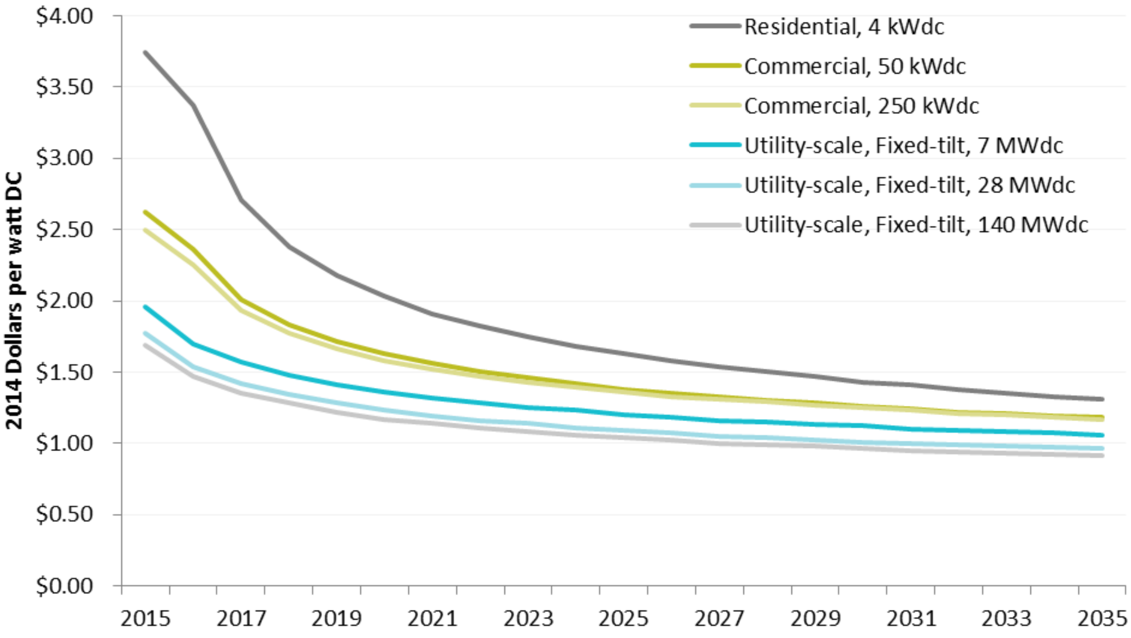
FIGURE 7-2: Distributed solar PV system



7.1.2.2 Solar Generation Market Research

B&V developed cost estimates for representative distributed and centralized PV systems for 2015 and forecasted those costs on an annual basis through 2035. This section focuses on distributed solar, while Section 7.2.2, Solar Photovoltaic, provides additional details on centralized solar resources. One of the major assumptions of the forecast is that installed PV prices will meet the DOE's SunShot Initiative[151] targets in 2020, resulting in a large decline from today's costs. B&V projected residential system costs to drop by approximately 65 percent, commercial system costs by approximately 55 percent, and centralized systems by approximately 45 percent (see Figure 7-3).

FIGURE 7-3: Solar cost projections (2014$ per Wdc)



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[151] "The SunShot Initiative aims to reduce the total installed cost of solar energy systems to $.06 per kilowatt-hour (kWh) by 2020". For more information see: http://energy.gov/eere/sunshot/sunshot-initiative-mission.

PGE has approximately 65 MWdc of distributed generation solar on the system consisting of multiple programs. The Company participates in the state of Oregon's Solar Volumetric Incentive Rates Program (effectively a feed-in tariff, or "FIT" program), for which it has a 16 MWdc cap. PGE has also developed several solar PV projects, including two solar highway projects: a 104 kilowatt direct current (kWdc) system that was the first solar highway project in the nation and a 1.75 MWdc project (Baldock Solar Highway). In partnership with customers, PGE is developing 3.5 MWdc of rooftop solar. PGE also purchases centralized solar PV generation totaling 14 MWdc.

7.1.2.3 Distributed Generation Solar Methodology

The distributed solar assessment focused on identifying the potential for solar installed on customer rooftops within PGE's service territory in northwest Oregon. B&V implemented an innovative approach to assess the technical potential using Light Detection and Ranging (LiDAR) data to evaluate the available area of individual buildings across PGE's service territory.

Incentives have long been an important part of the financials of PV, and Oregon has had some of the highest incentives for solar PV in the country. For example, the combined federal, state, and Energy Trust of Oregon (Energy Trust) incentives can reduce the installed cost of PV in Oregon by approximately 55 to 75 percent. This reduction strongly influences the payback of systems in 2016. The study assumed that by 2035 no incentives (tax credits or state incentives) would be available, since the market should be mature and self-sustaining by that time. While B&V forecasts cost declines of 55 to 65 percent for distributed PV systems by 2035,[152] these reductions are not enough to counteract the loss of incentives in many cases. Thus, the net cost after incentives to customers in real terms is actually lower in 2016 than it would be in 2035 for most cases.

In order to determine achievable potential within the study period, B&V used survey-based data to translate the payback distributions of customer systems to maximum market potential and then forecasted the adoption of solar over the study period. Using the results of surveys of residential and commercial customers' preferences for adopting solar and distributed generation, the National Renewable Energy Laboratory (NREL) (residential) and Navigant Research (Navigant) (commercial) developed national maximum market penetration curves, which indicate the likelihood of market penetration given a certain amount of payback for each customer class. NREL and Navigant calculated the maximum market potential was calculated for each customer class using the payback distributions for the 2016 and 2035 cases under the two rate increase assumptions.

Figure 7-4 summarizes the approach used to quantify the technical, financial, and achievable potential for distributed systems:

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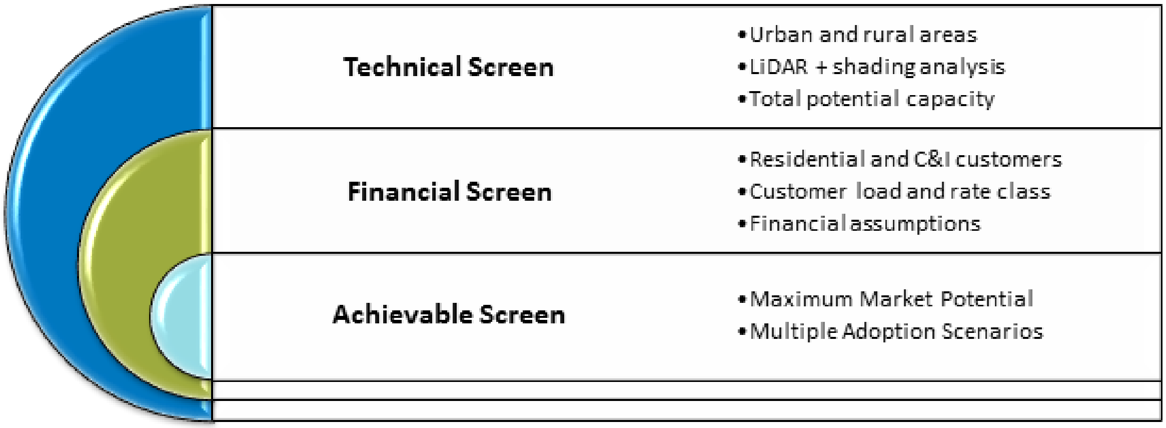
[152] This is a sharper decline in overnight capital cost than that projected for centralized solar below in Section 7.2.2, Solar Photovoltaic: 55-65% vs. 30%.

FIGURE 7-4: Quantification of distributed solar potential



- **Technical Screen.** The technical screen quantifies the amount of useable rooftop space on individual buildings across the urbanized areas of PGE's service territory. B&V restricted technical potential to those roof areas that receive adequate solar resources as defined by Oregon's eligibility requirements for tax credits and incentives. Next, B&V translated the rooftop space to total capacity (MWdc). B&V then extrapolated the analysis outside the urban areas to estimate the total technical potential in PGE's service territory.
- **Financial Screen.** For the financial screen, B&V developed site-specific characteristics to calculate the expected payback of individual buildings, accounting for solar profile, project size, and customer type. The financial screen limits sites to paybacks of 20 years or fewer for both residential and commercial customers. In two rate scenarios, B&V performed detailed financial analysis for hundreds of thousands of sites in the years 2016 and 2035.
- **Achievable Screen.** Black & Veatch developed estimates of achievable potential on the basis of the financial screen results and a range of market adoption scenarios. B&V developed forecasts on an annual basis from the year 2016 through 2035. This screen sought to identify the higher and lower bounds of solar adoption potential over time using two approaches: bottom-up and top-down.

7.1.2.4 Distributed Generation Solar Summary

The technical potential for distributed solar is significant in PGE's service territory, but continued incentives or alternative financing, such as leasing, are necessary to sustain higher levels of adoption. The study findings indicate that, given forecasted capital costs, the market potential by 2035 will continue to require incentives or alternative financing, at some level to support growth of the market. Otherwise, without additional incentives or alternative financing, the maximum market potential is constrained, meaning there is a limited pool of customers who would choose to adopt solar PV despite solar being financially viable.

However, as the last six years illustrate, the solar industry reduced prices at a pace that was significantly shorter and faster than analysts expected. Third-party solar developers provide financing options such as leases. Growth in distributed solar continues in PGE's service territory through net energy metering and, until it reached full subscription, Oregon's version of the solar feed-in tariff program.

7.1.3 Non-Solar Distributed Generation Market Assessment

The B&V study on non-solar distributed generation examined the potential of three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines. The assessment covered various technologies within each class that are most practical for behind-the-meter, customer-sited applications for commercial customers. These technologies include the following:

- Battery Energy Storage Systems (BESS)
  - Lithium ion
  - Vanadium redox flow battery
- Fuel Cells (Natural Gas)
  - Solid oxide fuel cells (SOFC)
  - Molten carbonate fuel cells (MCFC)
  - Phosphoric acid fuel cells (PAFC)
- Microturbines (Natural Gas)

The study first considered the technical characteristics, the status of each of the technologies, and current and forecasted costs of the various technologies. To understand project financials, B&V modeled each of the technologies for a number of commercial customer types using a modified scripting of the NREL System Advisor Model (SAM) software. The model incorporates the following with customer load data:

- Technical performance parameters;
- System capital and O&M costs;
- Project financing and taxes;
- Incentives;
- Utility rate data.

The suite of results includes net present value (NPV), payback period, LCOE, annual cash flow, and annual energy savings.

B&V modeled scenarios for 2016 and 2035 for all technologies and customer types. For BESS, B&V tested the system with and without PV. It was important to use different customer types to understand how diverse load shapes may benefit, through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. For each customer type, B&V sized each of the technologies to meet either the customer load or minimum technology unit size. For both the 2016 and 2035 cases, B&V tested two utility rates escalating two ways:

1. At the Consumer Price Index (CPI) of 2 percent.
2. At CPI plus 1 percent (CPI + 1).

B&V tested fuel cells and microturbines under base and low gas price scenarios.

Developing estimates of achievable potential for the DG technologies examined in this study proved challenging for two reasons:

1. The technologies considered are not financially viable in the near-term under current financial conditions; and
2. The long-term cost outlook is quite uncertain for many of these technologies.

Appropriately sizing the systems (or properly matching the system to a customer's load shape) drives the financials. In order for the technologies to be financially viable, the following would need to happen:

- A substantial drop in technology costs;
- Implementation of additional policies and incentives; and
- Rate structure changes designed to promote adoption.

Absent these conditions, B&V forecasts minimal adoption of these technologies over the study period.

If any adoption occurs, it would be towards the latter decade (2026 to 2035) of the analysis period, when better clarity on costs is available. (See Table 7-1 below for annual adoption estimates.) The one major caveat in this study is that B&V focused on the impact of these systems on customer electricity bills, but did not account for the value of reliability and power quality to the customer. These factors are much more difficult to value and could vary widely by customer type. Only BESS technology makes some financial sense by 2035.

TABLE 7-1: Forecasted annual BESS adoption

BESS Capacity (MW/MWh)	2016 to 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Adoption	0	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2
High Adoption	0	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4

7.1.3.1 Combined Heat and Power

In 2014, ICF International issued a report for the Oregon Department of Energy assessing the market potential of CHP in Oregon. Approximately 22 percent of the existing CHP technical potential for CHP in Oregon has economic potential with a payback of less than 10 years. The economic potential is available only in Pacific Power & Light and Portland General Electric territory. While the calculated economic potential and market penetration figures provide insight into the amount of CHP and waste heat to power (WHP) that could penetrate the market in Oregon, there are other factors and uncertainties that affect the economics expected market penetration. Implementation of CHP is site-specific and necessarily driven by customer economics and requirements. As such, PGE does not explicitly add CHP to portfolios. The results of the analysis are for both PGE and PacifiCorp's service territories and suggest there is 90.4 MW of cumulative CHP potential between 2015 and 2030.

Appendix J, ICF International Assessment of the Technical and Economic Potential for CHP in Oregon, contains the complete study.

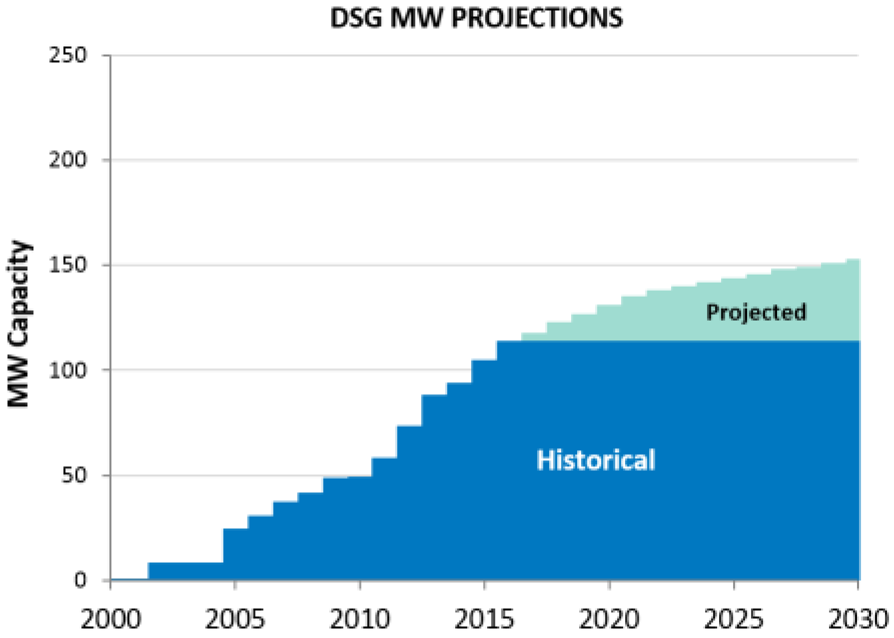
7.1.4 Dispatchable Standby Generation

PGE began the Dispatchable Standby Generation (DSG) program as a pilot program in 2000. The first site was a 500 kW generator installed by the State of Oregon Youth Authority at the MacLaren Youth Correctional Facility.

FIGURE 7-5: Generator at MacLaren Youth Correctional Facility

The pilot succeeded in demonstrating both the technical and financial effectiveness of the DSG concept. The program has grown in the intervening years, and as of June 30, 2016 had 105 MW of DSG capacity provided from 76 generators at 54 different sites with 35 customers.

FIGURE 7-6: PGE's DSG growth projections



7.1.4.1 History of PGE's DSG Program

How the Program Works

The DSG program partners PGE with commercial and industrial customers who have a need for emergency, standby generation greater than 250kW. Reciprocating diesel engines normally power these standby generators. PGE contracts for the use of customers' standby generators when the local region has a critical need for power. Through deployment of communications and control technology, PGE can remotely start the generators to supply excess power to the grid when the region has a critical power need.

FIGURE 7-7: DSG at Quorvo (formerly Triquint Semiconductor) in Hillsboro, Oregon

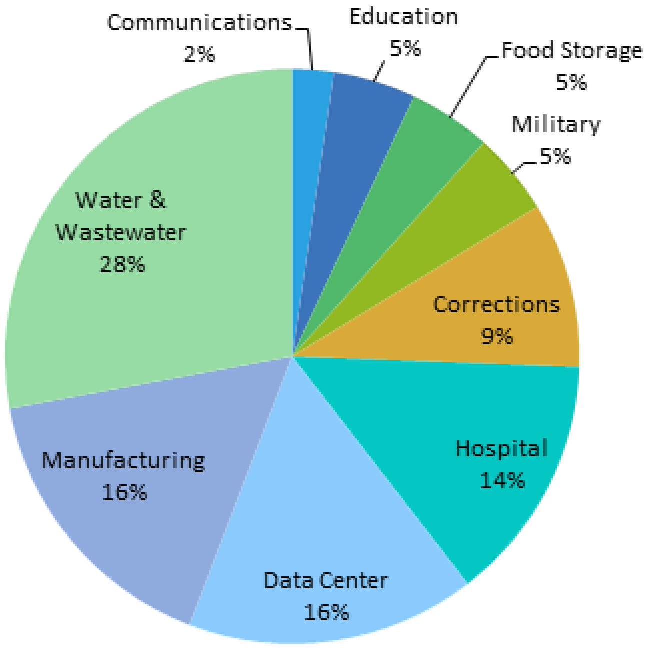
Under the DSG program, PGE is responsible for communication, metering, control equipment, generator maintenance, and fuel costs. PGE typically pays for the incremental capital costs of implementing the DSG program at the customer site (controls, communications, switchgear, etc.). If a customer site is already capable of operating in DSG mode, PGE provides the customer with an aid-in-construction payment to compensate the customer for implementing that capability.

The customer ultimately controls the dispatchability and operation of the generator and is responsible for securing the appropriate permits to enable the use of the generator in PGE's program. The typical DSG agreement is for a term of 10 years. PGE uses the DSG capacity to help meet its non-spinning reserve requirements. The fact that the generators are located throughout PGE's service territory is a benefit. The program also helps PGE reduce risks associated with transmission and fuel supply.

Market Segments

Customers in a variety of different markets participate in PGE's DSG program. As shown in Figure 7-8, major markets include healthcare, semiconductor manufacturing, wastewater and fresh water treatment/pumping plants, municipal and educational facilities, corrections, and datacenters. DSG customers are generally located in the larger metropolitan areas of PGE territory, but there are a few exceptions to that rule.

FIGURE 7-8: DSG customer segments



Accomplishments

Domestic and international utilities have given significant attention to PGE's DSG program—visiting the DSG Command Center and various customer sites to learn about the program. Due to high levels of customer interest and participation in the program, PGE's DSG program is one of the most successful customer-based distributed generation programs of its kind. To PGE's knowledge, the Company's DSG program is the leading utility distributed generation program (in enrolled MW) that utilizes customer generators.

7.1.4.2 Benefits of the DSG program

PGE Benefits

The DSG program offers a low cost distributed generation resource, which PGE uses to help satisfy required non-spinning reserve needs. The cost of the DSG program is approximately $38 per kW-year (including capital and fixed O&M).

Customer Benefits

Customers that have a DSG generator system partner with PGE to obtain a more reliable and versatile generator system.

PGE's program covers some of the O&M costs of the generator system for the customer. Because each customer system is an integral part of PGE's DSG program, the Company also offers customers enhanced monitoring and metering. PGE monitors the system on a 24/7 basis, thereby offering customers an additional "set of eyes" on their system, or some valuable redundancy.

PGE manages maintenance for the large number of generators participating in the program. The Company has also developed a high level of expertise in troubleshooting, analyzing problems, and finding solutions to issues with the generator systems. The DSG control system has good data logging and reporting capabilities that are often lacking in less sophisticated generator systems – thus, PGE can more easily understand and resolve problems.

Finally, DSG customers are able to transition from generator to the grid without any outages to the loads – a make-before-break switching. This ability is attributable to the inherent nature of a paralleling generator system, which allows the generator output connected to the utility grid to perform "closed transitions" into and out of the parallel mode. Thus, PGE only disturbs loads once—in the event of an outage, instead of twice—once from the outage itself, and once from an open transition (a break-before-make switch operation back to the utility).

7.1.4.3 DSG Actions since the 2013 IRP

The 2013 IRP Action Plan had a goal of 116 MW of DSG capacity in 2017. PGE is currently on track to achieve 116 MW of DSG capacity in late 2016. Additionally, the Company has a queue of customers in for potential DSG construction in 2017 and beyond.

7.1.4.4 Future Plan for DSG

The DSG program currently helps fulfill some of PGE's non-spinning reserve requirements; however, PGE can only use the generators when the local region has a critical need for power. These requirements vary based upon the amount of generation that PGE is operating, system load, and how much spinning reserve is available. PGE estimates that the DSG program could grow to meet the majority of the Company's standby capacity needs (non-spin).

7.2 Renewable Resources

7.2.1 Wind

Utilities currently rely on wind generation projects to meet a majority of Oregon's renewable portfolio standard (RPS) requirements. As technological advances continue, turbines, towers, and rotors have continued to evolve. New centralized wind projects range between 100 and 1000 MW, but may be smaller or larger depending on several technical, geographic, and permitting factors.

Variable energy resources (VERs), like wind, do not provide the same level of capacity or ancillary services benefits as dispatchable generators. Utilities must combine VERs with other resources to achieve the same level of system reliability. Increased scale and technology enhancements are improving both the efficiency and economics of wind projects. As a result, geographically advantaged wind sites that demonstrate wind speeds correlated to the technology type and lower interconnection costs may be cost-competitive for energy production (with the production tax credit or "PTC"), compared to other generation alternatives.

To make wind more competitive, wind turbine manufactures are innovating technology, such as increasing rotor diameter, to better utilize lower wind speed sites. Manufacturers also developed options for tower heights from 80 meters up to 140 meters, making it possible for wind turbines to capture stronger and more consistent wind at higher heights. The significant scaling of wind turbines, blades, and projects is increasing capacity factors for wind projects, making them more cost-competitive.

In this IRP, PGE evaluated wind performance based on capacity factors provided by DNV GL for two representative regions:

1. Oregon – Columbia River Gorge
    a. Site in the Oregon region with an average wind speed at the 80-meter hub height of 6.6 meters per second (m/s)
    b. Technology identified as GE 2.0-116
    c. Estimated capacity factor of 34 percent
2. Central Montana
    a. Site in the central Montana region with an average wind speed of 8.2 m/s at the same 80-meter hub height
    b. Technology identified as GE 2.0-116
    c. Estimated capacity factor of 42 percent

Transmission availability and integration costs can be constraints for the development of new wind facilities. The most viable Pacific Northwest wind sites are on the east side of the Cascades. Montana appears to offer significant wind resource opportunities; however, the potential cost of constructing new transmission lines or securing alternative means to move the power to large load centers in Washington and Oregon is highly uncertain and difficult to estimate. As such, this IRP does not attempt to directly estimate the incremental cost of transmission service associated with a remote wind resource. Rather, PGE describes the methodology and results of a transmission break-even cost in Chapter 12, Modeling Results.

This IRP focuses on the present value cost difference between portfolios, including central Montana wind resources and identical portfolios making use of Oregon region wind paired with BPA transmission service. The a priori assumption is that the capacity factor and capacity contribution advantages will reduce the cost of the portfolio, including the central Montana wind resources, relative to the portfolio including the Oregon wind resource. The difference in cost will serve as a reasonable proxy for the budget PGE could allocate for transmission, while remaining indifferent in terms of present value cost.

7.2.1.1 PGE Variable Energy Integration Study

In 2007, given projections for a significant increase in wind generating resources, PGE began efforts to forecast costs associated with the self-integration of wind generation. These efforts entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming. PGE intended this integration study to be the initial phase of an ongoing process to estimate wind integration costs and refine the associated model.

In October 2009, PGE began Phase 2 of its Wind Integration Study and contracted for additional support from EnerNex,[153] which provided input data and guidance for Phase 1. A major driver of Phase 2 was the expectation that the price for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly in the future, as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources. PGE believes that BPA's VER balancing services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in the Phase 2 study.

PGE conducted a Phase 3 internal study to inform the decision for the BPA Fiscal Year 2014-2015 election period for wind integration services. The result of the study was a PGE election to contract with BPA to provide regulation, load following, and imbalance (30 minute persistence forecast for a 60 minute schedule) services for Biglow Canyon for the term of the 2014-2015 election period.

In its 2013 IRP, PGE conducted a Phase 4 wind integration study. A significant goal for Phase 4 was to include additional refinements[154] for estimating PGE's costs for self-integration of its wind resources and to determine the sensitivity of wind integration costs to gas price variability. During the Phase 4 process, PGE reprogrammed and refined the wind integration model into the Resource Optimization Model (ROM) and held a public technical workshop to discuss progress, enhancements, and various modeling details. Commission Staff, the Oregon Department of Energy (ODOE), and other interested parties, who participated in PGE's 2013 IRP proceedings (OPUC Docket No. LC 56), attended the workshop. In addition to this public review, the external Technical Review Committee (TRC) carefully evaluated the Phase 4 data and modeling methodology, and provided valuable insight and information.

Consistent with earlier versions, the ROM is a multi-stage dispatch optimization model that employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS)[155] programming and a Gurobi Optimizer.[156] Each version of ROM incorporates and builds on improvements made in previous versions of the model. The Phase 4 model updates included:

- Separate increasing ("INC") and decreasing ("DEC") reserve requirement formulations for regulation, load following and imbalance reserves;

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[153] EnerNex is also a leading engineering and consulting services firm, providing services to government, utilities, industry, and private institutions.

[154] Some of the refinements stem from suggestions received during the "Next Steps" section of Phase 2.

[155] GAMS is a high-level modeling system for mathematical programming and optimization that PGE used to program/compile the objective function and operating constraint equations.

[156] The Gurobi Optimizer is a state-of-the-art solver used to solve the resulting constrained optimization problem.

- Gas supply constraints limiting gas plant fuel usage to the Day-Ahead nomination levels +/- drafting and packing limits on the pipeline;
- Ability to economically feather wind resources; and
- Implementation of the dynamic transfer constraint to allow for limited intra-hour dynamic capacity provision for Boardman, Coyote and Carty.

7.2.1.2 Introduction to Phase 5 Study and Scope

The primary goal of the Phase 5 study was to refresh PGE's integration cost estimates and evaluate the impact of increasing levels of VERs. Due to market development activities in the west, the PGE IRP and ROM teams determined it is appropriate to update the base assumptions to reflect a future state of a liquid, sub-hourly market in the west. For this IRP, PGE conducted four model runs to estimate the integration costs of scenarios with differing levels of VERs. Each subsequent model run incorporates and builds on the assumptions of the base run. The model runs and assumptions are:

- **Run 1.** PGE does not self-integrate any VERs (base run)

  Assumptions

  - 2021 test year
  - PGE’s existing VER fleet of Biglow Canyon and Tucannon River (717 MW nameplate capacity)
  - Generic combined cycle gas plant replaces Boardman
  - Reduced Mid-Columbia generation
  - Liquid sub-hourly market is available for energy transactions only
  - Reference case gas and power prices
- **Run 2.** PGE self-integrates existing variable energy resources

  Assumptions

  - Run 1 assumptions
  - PGE self-integrates Biglow Canyon and Tucannon River
- **Run 3.** PGE self-integrates existing variable energy resources and additional wind resources

  Assumptions

  - Run 2 assumptions
  - PGE also self-integrates a 318 MW capacity, 111 MWa generic Columbia River Gorge wind resource
- **Run 4.** PGE self-integrates existing resources as well as additional wind and solar resources

  Assumptions

  - Run 3 assumptions
  - PGE also self-integrates a 135 MW capacity (AC), 30 MWa generic central Oregon solar resource

As in previous integration studies, the Phase 5 process included seeking input, review, and feedback on assumptions, inputs, and model changes from an external TRC.

Model Enhancements List

Prior to initiating the Phase 5 study, the ROM project team and other subject matter experts identified the need to upgrade the model in order to run the model at a more granular time step. Prior to the upgrade, the model was Excel based and limited by the amount of data that could be stored while maintaining stability. As part of the upgrade, PGE migrated the data storage element of the model to a database environment and redesigned the import/export links for more efficient data storage. As a result, ROM is now able to successfully run at the fifteen minute granularity while maintaining stability and acceptable run times.

ROM's Phase 5 model enhancements include:

- **Fifteen-minute dispatch granularity.** If the input data is available, the model can also run at any granularity between fifteen minutes and one hour.
- **User defined number of stages.** Previously, ROM restricted users to three stages. The user now has the capability to define as many or as few stages as desired, assuming the input data is available.
- **Stage-specific dispatch granularity.** PGE can now effectively run the model with each stage or a group of stages running at different granularities (e.g., hourly dispatch for the first and second stages, and fifteen minute for the third).
- **Day-ahead unit commitment.** The user now has the ability to specify which units can start or shut down in each stage of the model. Generally, fuel constraints ensure appropriate unit commitment, but this added capability reduces the potential for error and decreases run time.

Results

Table 7-2, below, shows the results of the VER integration study. The estimated costs are on a per MWh basis (in 2021$) and are calculated by computing the difference between the total cost of a particular run and the base run, then dividing by the VER MWh of the particular run.

TABLE 7-2: Results of VER integration study

Scenario	VER Capacity (MW)	VER Energy (GWh)	Integration Cost ($/MWh)
Run 2	717	1,973	$0.99
Run 3	1035	2,947	$0.91
Run 4	1160	3,210	$0.92

PGE predicates each of these scenarios on the base assumption of some future liquid sub-hourly market that transacts on a fifteen-minute basis and the assumptions provided above.

It is important to note that ROM only estimates variable operating costs (e.g., fuel, wear and tear, variable operations and maintenance). As a result, PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, fixed costs and other capital investment, and the potential need for personnel additions to manage the self-integration VERs. PGE will need subsequent phases and studies, in order to analyze changes in the supply and mix of VERs, the associated demand for flexible balancing resources, portfolio diversity, and the regional market structure.

Future Enhancements/Next Steps

As the capabilities and sophistication of PGE's modeling expands, the Company continues to identify future enhancements to ROM and potential study topics to support future IRPs and other planning efforts. Future enhancements to the model may include:

- Refinement of reserves modeling.
- Energy and fuel storage.
- Increased model granularity (e.g., 5 minute dispatch).
- Flexible optimization periods (e.g., annual, monthly, weekly, or daily windows).

Future studies may focus on:

- Diversity of balancing resources and portfolio mix; and
- Locational and temporal diversity of VER locations and fuel types.

PGE will continue to refine and develop the model and analytical techniques in order to be able to quickly adapt and evaluate industry changes, and ensure the Company is able to evaluate and capture value for customers.

7.2.2 Solar Photovoltaic

Solar power is a small, but growing component of the PGE renewable resource mix. Solar has a more predictable generation profile than wind. Moreover, distributed solar projects, connected directly to PGE's system, are not subject to the same transmission constraints as central station projects located outside of PGE's system.

PGE has a strong history of supporting rooftop and centralized solar PV generation. This section focuses on centralized solar, while additional details on the distributed solar resource are included in Section 7.1.2, Distributed Generation Enabling Studies, above.

Figure 7-9 provides an image of the components of a centralized solar PV system.

FIGURE 7-9: Centralized solar PV system

The Company has approximately 65 MWdc of distributed generation solar on the PGE system consisting of multiple programs. PGE participates in the state of Oregon's Solar Volumetric Incentive Rates Program (effectively a feed-in tariff, or "FIT" program), for which it has a 16 MWdc cap. PGE has also developed several PV projects, including two solar highway projects: a 104 kilowatt direct current (kWdc) system that was the first solar highway project in the nation and a 1.75 MWdc project (Baldock Solar Highway). In partnership with customers, PGE is developing 3.5 MWdc of rooftop solar. In addition to DG solar resources, PGE purchases utility-scale PV generation totaling 14 MWdc.

7.2.2.1 Centralized Solar PV Modeling in the IRP

PGE models centralized (utility-scale) PV systems for portfolio analysis in this IRP (see Chapter 10, Modeling Methodology) based on information provided by DNV GL.[157] To assist the Company in conducting portfolio level analyses on solar, PGE engaged DNV GL to provide technical and financial information related to potential solar generation projects. DNV GL provided PGE an analysis of two generic solar projects with parameters consistent with those of a project located in Christmas Valley, Oregon:

1. Christmas Valley Solar 1
    a. Average Capacity: 25 MWa (115 MW nameplate capacity)
    b. Generation Technology: Solar (fixed tilt)
2. Christmas Valley Solar 2
    a. Average Capacity: 25 MWa (103 MW nameplate capacity)
    b. Generation Technology: Solar (single axis tracking)

In the 2016 IRP, PGE modeled the single-axis tracking system. Relevant assumptions employed in the development of performance and cost parameters for that system include the following:

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[157] See Appendix M, Evaluation of Five Renewable Supply Options (DNV GL), for the DNV GL report.

- SolarAnywhere provided the meteorological data used for the project.
- DNV GL used PVsyst software[158] to calculate net energy, assuming spacing and loss factors considered reasonable for the region and type of technology.
- DNV GL assumed a DC capacity factor of 18.1 percent with DC/AC ratio of 1.2. DNV GL also assumed a 30 degree tilt with due south orientation, normalized by dc capacity, a performance ratio of 79.5 percent, and a loss factor for inverter clipping.
- DNV GL also assumed the following:
  - An expected forced outage rate of 1 percent.
  - A panel efficiency of 15.5-16 percent.
  - An inverter efficiency of 98-99 percent.
  - 72 cell panels.
  - An approximate footprint of 7 acres per MW.
- The specific commercial equipment selected for the purposes of conceptual design, system modeling, and cost estimates is representative of Tier-1 manufacturers. DNV GL assumed the remaining balance of systems equipment and materials to be typical for this type of project.
- The annual capacity factor is 24.2 percent.

7.2.2.2 Centralized Solar PV Methodology

The centralized solar potential assessment focused on areas across Oregon for projects ranging from 5 to 250 MWac. B&V first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, B&V applied a financial screen to these sites by comparing each site’s levelized cost of energy (LCOE) to PGE’s long-term qualifying facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, B&V applied an additional screen to the sites, assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE’s service territory and the size of projects that can interconnect. This assumes utilities build no new transmission in Oregon.

7.2.2.3 Centralized Solar PV Summary

With the recent longer-term ITC extension and updated avoided cost pricing, the potential for DG and centralized solar likely looks different from what the findings in this study suggest. PGE has executed solar qualifying facility (QF) power purchase agreements (PPA) for over 200 MW since July 2015. Prior to July 2015, PGE had executed PPAs for less than 10 MW of solar QFs.

Without the ITC available, the B&V study showed that for centralized solar, the long-term avoided cost pricing for variable solar, as used by B&V in the study, appears not to be sufficient to drive long-term, large-scale solar adoption in Oregon. When the ITC was available at 10 percent, cost-effective solar became possible by 2026. Additional penetration was also possible if developers were willing to build projects for less than the assumed return requirements of 6.5 percent, capital costs were

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[158] PVsyst is an industry standard modeling tool for PV systems developed by the University of Geneva in Switzerland.

lower than forecast, or the industry placed more value on large-scale solar than just avoided cost pricing.

Table 7-3 summarizes the achievable potential identified by B&V for both distributed-scale and centralized systems.

TABLE 7-3: Summary of solar potential assessment

Potential	Technical screen	Financial screen by 2035	Achievable screen by 2035
Distributed (MWdc)	2,810	1,410	125 to 223
Centralized (MWac)	56,000	7,500 to 17,500	100 to 369

MWdc = megawatts direct current
MWac = megawatts alternating current

7.2.2.4 Potential Carty Solar Farm

PGE is assessing the potential of centralized solar generation in Oregon. The company is exploring the development of a 50 MW photovoltaic site adjacent to the Carty Reservoir. This site provides the opportunity to reduce project costs by making use of existing company property, nearby infrastructure, and favorable solar insolation levels. A solar farm at the Carty site would bring technological and locational diversity to the Company's existing renewable portfolio.

7.2.3 Biomass (including Boardman Feasibility)

Biomass energy is the energy generated from plants and plant-derived materials. Direct biomass combustion power plants use the Rankine steam cycle.[159] When burning biomass, pressurized steam generates in a boiler and then expands through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing (e.g., grinding, drying) to improve the physical and chemical properties of the feedstock. Advanced technologies, such as integrated biomass gasification combined cycle and biomass torrefaction[160] or pyrolysis, are under development but have not achieved widespread commercial operation at grid scales.

Wood is the most common biomass fuel. Other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Due to the dispersed nature of the feedstock and the large quantities of fuel required, biomass plants typically have a 50 MW or less capacity. As a result of the smaller scale of the plants and lower heating values of the fuels (as compared to fossil fuels), biomass plants are generally less efficient than modern fossil fuel plants. Also, added transportation costs tend to make biomass more expensive than conventional fossil fuels on a $/MMBtu basis.

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[159] The Rankine cycle is the fundamental operating cycle of all power plants where an operating fluid is continuously evaporated and condensed (e.g., water is pumped in to a boiler where heat from a burning fuel boils the water to make steam to turn a turbine to make electricity; the used steam is condensed back to water and pumped back to the boiler).

[160] Torrefaction is a roasting process (often applied to biomass) in an airless environment at about 540ºF, which removes moisture and a high percentage of volatile substances to create a harder fuel that is easier to store, move, crush, and burn in a power plant.

Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly becoming a way to restore a positive balance to forest ecosystems, while avoiding uncontrolled and expensive forest fires.

Many view biomass as a near carbon-neutral power generation fuel. While biomass combustion causes the emission of carbon dioxide (CO_2), a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. The CO_2 re-absorption time will be potentially longer when fueling with woody biomass (e.g., forest thinning). Furthermore, biomass fuels contain lower levels of sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2). Biomass fuels may also contain relatively lower amounts of toxic metals, such as mercury, cadmium, and lead.

Biomass combustion facilities typically require technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to meet state and or federal regulatory requirements.

7.2.3.1 Boardman Biomass Project

PGE continues its research efforts to assess the technical and economic viability of biomass fuel conversion at the Boardman plant. As discussed in Chapter 3, Planning Environment, PGE will cease coal-fired operations at Boardman by year-end 2020, and biomass energy generation could commence subsequent to this cessation.

One question the Boardman Biomass Project seeks to answer is whether torrefied biomass can be an acceptable substitute for the Powder River Basin (PRB) coal that Boardman was designed to use. If torrefied biomass is a technically acceptable substitute for PRB coal, the fuel supply chain needs to offer an economic solution that can compete with energy- and capacity-equivalent renewable resources. PGE's efforts to-date have centered on addressing these two points, and ultimately a one full-power day equivalent test burn.

One full-power day equivalent requires approximately 8,000 tons of torrefied biomass. In December 2015, PGE issued an RFP for torrefied biomass to 16 suppliers; the RFP yielded 10 responses. PGE narrowed the field to three potential vendors with one vendor being appealing in terms of meeting technical requirements, price, and commercial viability. The vendor would derive the 8,000 tons of biomass from hardwood and saw mill residue from Eastern Seaboard states. Following a detailed assessment of technical and commercial viability that included vendor-site visits, PGE established a path to move forward. That plan called for vendor samples to be test milled and combusted at the Western Research Institute (WRI), and also for procurement of 100 tons of torrefied biomass fuel sample for testing and observation. While the vendor provided enough material for successful testing at WRI; it failed to provide, in a timely manner, more material for additional WRI testing. Moreover, the vendor was unable to make any headway in producing the 100 ton test quantity. In August 2016, PGE notified the vendor that the Company would cease any interest in the vendor's capabilities due to the vendors' non-performance.

PGE promptly sought a new source for the 8,000 tons of torrefied biomass fuel required to complete the one full-power day equivalent test burn. Oregon Torrefaction, LLC (Oregon Torrefaction) committed to provide PGE with the 8,000 tons of torrefied biomass. Oregon Torrefaction has been working closely with partners (many in the PNW) up and down the supply-chain to assure sufficient delivered torrefied fuel supplies for a November 2016 test burn. Oregon Torrefaction's biomass supply relies largely on regionally available softwood (derived from forest thinnings for forest health) small diameter logs partially burned from forest fires, and insect damaged woody material. PGE will accomplish torrefaction via a mobile torrefier on loan from the Idaho National Laboratory (INL) of the United States Department of Energy, as well as from a stationary torrefier in close proximity to the Boardman Generating Station. The delivered fuel will be subject to extensive qualitative and quantitive quality assurance testing to ensure it meets PGE's fuel quality specifications.

Chapter 10, Modeling Methodology, provides the framework that PGE uses in this IRP to help assess the potential cost-competitiveness of the Boardman Biomass Project relative to other available resources. Chapter 12, Modeling Results, discusses the results of our analysis.

PGE anticipates that Boardman biomass can function as a seasonal resource, based on either market economics or system needs to maintain resource adequacy. PGE continues to assess fuel supply options, including existing sources of agricultural and forestry residue.

Biomass at Boardman could help meet future Oregon RPS requirements and help diversify PGE's renewable resource portfolio. Biomass at Boardman would provide a unique source of dispatchable, renewable energy, and a peak capacity value. Should testing confirm technical feasibility, PGE's next key steps will focus on:

- Identifying sufficient cost-effective biomass fuel sources.
- Assessing the overall project economic and risk mitigation value of Boardman biomass relative to other renewable resource alternatives.
- Establishing the path forward for the planning and permitting process in light of PGE's future RPS obligations and the timing for any competitive bidding process.

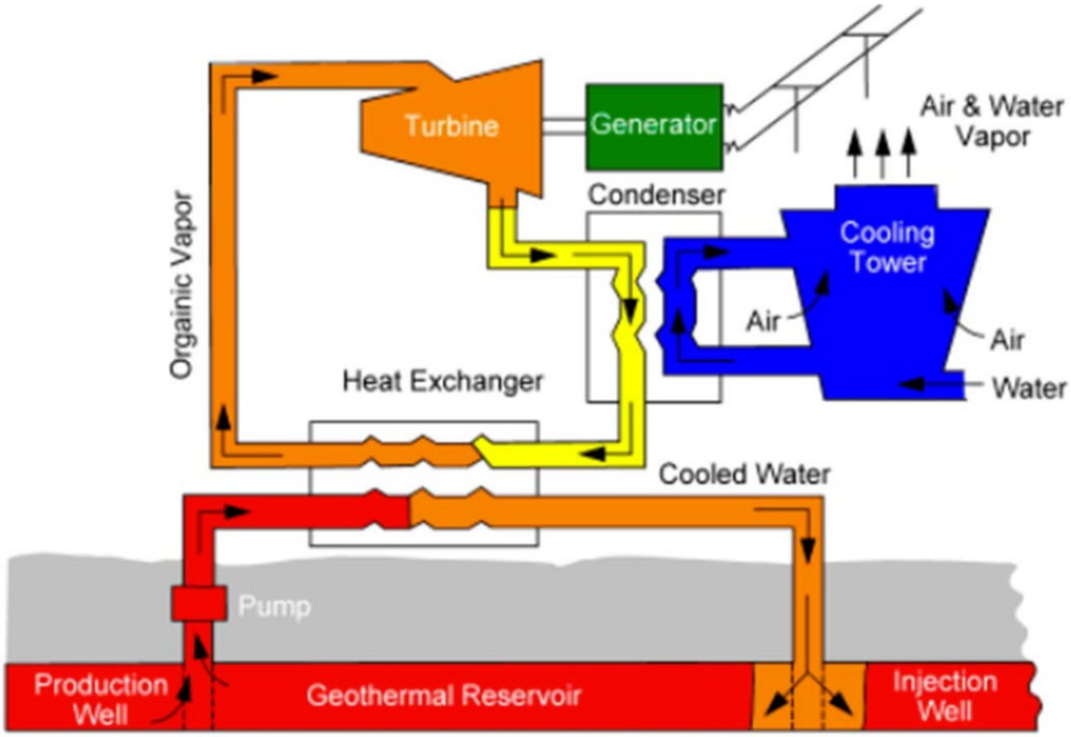
7.2.4 Geothermal

Geothermal power uses steam or a secondary working fluid in a Rankine cycle to produce electricity. The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. Efforts are underway to develop "enhanced geothermal" projects.

The temperature and quality of the steam/liquid extracted from the geothermal resource area primarily drives the choice of geothermal technology. Considering the temperatures associated with geothermal resource areas located in Oregon, PGE anticipates that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems, as described below:

- **Binary geothermal.** Binary cycle systems develop liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350°F or 177°C). In a binary system, a secondary fluid captures the thermal energy of the brine and operates within a Rankine cycle.

FIGURE 7-10: Binary geothermal system



Source: Colorado Department of Natural Resources

- **Enhanced geothermal (or "hot dry rock").** For geologic formations with high temperatures, but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, achieving a functional geothermal resource requires the hydraulically fracturing of the geologic structure. While developers are currently demonstrating enhanced geothermal projects around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not commercially viable.

Due to the technical and cost uncertainty of enhanced geothermal systems, B&V selected binary geothermal options for PGE's analysis. B&V developed performance and cost parameters for a 35 MW-net binary geothermal facility with an 85 percent capacity factor. About 90 percent of systems currently under development in the U.S. are binary. Finally, based on the typical size of potential Oregon resources as discussed below, PGE chose to model the performance and cost parameters for a 35 MW binary facility.

Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F or 177°C) or for brines with high dissolved gases or high corrosion or scaling potential. Project developers typically use dry cooling with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems.

According to the U.S. Energy Information Administration (EIA), Oregon ranks third in the nation for geothermal potential, after Nevada and California.[161] The total estimated geothermal generation potential in the state of Oregon is approximately 2200 MW.[162] California and Nevada have potentially thousands of MWs available for development. However, PGE currently faces significant transmission constraints in moving energy produced in either California or Nevada to PGE's service territory.

Challenges to developing geothermal generation include permitting (as many of the best resources are on federally-managed lands) and the risk that test wells will not produce economic energy (dry-hole risk).

Commercial-scale geothermal energy appears to be a limited generation alternative for PGE. Current subsidies under the federal PTC and from the Energy Trust[163] may make some projects more cost-competitive, if transmission is accessible. Actual project costs can vary significantly, based on the hydrothermal reservoir quality and location relative to transmission.

7.3 Thermal Resources

In this IRP, PGE selected three types of power plants to represent thermal resource options:

1. Combined cycle combustion turbines (CCCT), 400 MW,[164] H-class GE technology;
2. Simple cycle combustion turbine (SCCT), 230 MW[165] F-class GE technology with rapid start capability; and
3. A group of six reciprocating engines at 110 MW.[166]

Natural gas fuels all of these thermal resources, and they each use wet cooling towers.

Worldwide, coal and nuclear technologies may still be viable options for new construction. PGE's study focused on the western part of the United States, where several constraints make it infeasible to pursue these resources in the near future. More precisely, among other factors:

- Carbon regulation is imposing a reduction of the carbon footprint of power generation to levels unachievable with coal.
- Clean coal technologies are still not largely available on a commercial scale, and the modeling of these technologies remains too speculative for this IRP.[167]

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[161] U.S. Energy Information Administration, State Profile and Energy Estimates, available at http://www.eia.gov/state/?sid=OR - tabs-4, retrieved on June 24, 2016.

[162] U.S. Energy Information Administration, State Profile and Energy Estimates, https://www.eia.gov/state/analysis.cfm?sid=OR, retrieved on June 24, 2016. Oregon currently has geothermal sites in multiple counties throughout the state, including Malheur, Klamath, and Lake County.

[163] See http://www.energytrust.org/geothermal/index.html for more information on ETO subsidies available for geothermal projects.

[164] Net capacity, new and clean, ISO conditions (59°F, 60% relative humidity, sea level elevation).

[165] Id.

[166] Id.

[167] Further, the enactment of SB 1547 currently makes the modeling of clean coal technologies moot.

- The uncertainties around a federal repository for nuclear waste make it unlikely that most States in the WECC would issue a permit for a new nuclear plant.[168]

PGE is aware that technological breakthroughs, like cost-effective carbon capture or small scale modular nuclear, could make nuclear and coal options viable again, but in this IRP, the Company is not attempting to forecast the occurrence of those breakthroughs.

7.3.1 Natural Gas Resources

7.3.1.1 Combined Cycle Combustion Turbines

PGE has used combined cycle combustion turbines (CCCT) since the mid-1970s to provide energy to customers. Today, all of PGE's CCCT facilities use natural gas.[169] Combined cycle plants recycle the combustion turbine exhaust gas through a heat recovery steam generator (HRSG) to produce steam. PGE uses the steam from the HRSG to drive a steam turbine to generate additional electricity. Improvements in combustion turbine technology, such as forced cooling of the combustion parts, have increased efficiency of new units. CCCTs can also be equipped with duct firing to provide added generation capacity in the steam turbine (but with somewhat reduced overall efficiency).

In this IRP, PGE modeled a 400 MW GE 7HA.01[170] without duct firing. It is an air-cooled,[171] heavy frame combustion turbine generator (CTG) with:

- a single shaft, 14-stage axial compressor;
- 4-stage axial turbine; and
- 12-can-annular dry low NOx (DLN) combustors.

In the past, CCCTs served continuous load needs, given their ability to run on an ongoing basis very efficiently and serve average daily load. Newer models are also capable of higher ramping flexibility and shorter startup times without severe consequences on wear and tear and can, therefore, provide flexible capacity very efficiently.

7.3.1.2 Single Cycle Combustion Turbines

The GE7F.05 SCCT is an air cooled heavy frame combustion turbine generator (CTG). Based on information provided by B&V, the key attributes of the 7F.05 include:

- High availability.
- 40 MW/min ramp rate.

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[168] ORS 469.595 states that "[b]efore issuing a site certificate for a nuclear-fueled thermal power plant, the Energy Facility Siting Council must find that an adequate repository for the disposal of the high-level radioactive waste produced by the plant has been licensed to operate by the appropriate agency of the federal government. The repository must provide for the terminal disposition of such waste, with or without provision for retrieval for reprocessing."

[169] The only exception is PGE's Beaver plant, which is a dual fuel plant capable of running its CTs on diesel fuel.

[170] See Portland General Electric Company, "Characterization of Supply-Side Options," prepared by Black & Veatch, November 5, 2015 (providing a complete overview of the GE 7HA.01).

[171] It is important to note that air cooling is to the "combustion parts of the gas turbine," while the wet cooling towers serve the steam turbine condenser.

- Start to 200 MW in 10 minutes, full load in 11 minutes.
- Natural gas interface pressure requirement of only 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Water injected combustion with CTG NOx emissions of 42 ppm on diesel fuel.

The 7F.05 is GE's 5th generation 7FA machine with the latest advancements, including a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours. The 7F.05 units can start-up from 0 to 200MW in ten minutes and be at full load in 11 minutes.[172]

Over time, PGE projects that its loads will grow, existing contracts will expire, and changes to the generating fleet will occur. To maintain the ability to reliably serve load and supply required operating reserves, PGE must obtain additional capacity resources. In this IRP, PGE modeled the GE 7F.05, a frame type combustion turbine run in simple cycle, as the representative generic capacity resource used to fill portfolios' annual capacity deficits. PGE believes the 7F.05 to be representative of the costs and parameters of capacity resources that may generally become available in the future. As discussed elsewhere in this chapter, the 7F.05 also represents the lowest fixed cost dispatchable resource for which PGE obtained information for this IRP. Please refer to further discussions of resource attributes in Chapter 5, Resource Adequacy, and Chapter 13, Action Plan.

7.3.1.3 Reciprocating Engines

Reciprocating engines (e.g., Wärtsilä and Jenbacher) are another means of meeting capacity, load following, and variable generation resource integration needs. These internal combustion, piston-driven machines are designed to burn natural gas (or other fuels).

Wärtsilä offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs. Key attributes of the Wärtsilä 18V50SG include:

- High full- and part-load efficiency.
- Minimal performance impact during hot-day conditions.
- 10 minutes to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without material impact of maintenance costs or schedule.

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[172] Previous 7F CTGs could not start as fast as the 7F.05.

- Natural gas interface pressure requirement of 90 psig.
- Not dual fuel capable (the 18V50DF model can operate on both natural gas and liquid fuels).

The Wärtsilä engines have a max output of approximately 18.3 MW each. They can run independently, as well as in combinations at the same or different power levels. This provides an advantage over a GE LMS100 SCCT, in that the Wärtsilä engines are able to maintain a flatter, more efficient Heat Rate over a broader power range.

7.3.2 Next Generation Nuclear

Currently, Oregon state law prohibits the siting or construction of new nuclear plants, until such time as the U.S. Nuclear Regulatory Commission (NRC) approves an adequate repository for the disposal of high-level radioactive waste (ORS 469.595). As such, PGE's 2016 IRP does not include nuclear in the Company's portfolio analysis or current IRP resource acquisition horizon.[173]

To remain knowledgeable about new nuclear technology, PGE is a member of the advisory board for NuScale Power (NuScale)[174] , headquartered in Portland, Oregon. NuScale's Small Modular Reactor (SMR) design is promising technology which addresses some of the risk issues related to the old, large-scale nuclear plants. SMRs can be of any nuclear reactor technology, e.g., light-water, liquid metal cooled, Pebble Bed – with a single unit capacity of 300 MW or less. An SMR is a pressurized water reactor with passive safety features, which requires:

- No operator actions (i.e., self-cooling and shutdown).
- No AC or DC power.
- No external water.

Rather the SMR relies upon "physics, gravity, convection, and conduction" to coordinate operation and safe shutdown.

Currently, NuScale is only offering the 50 MW module, which is capable of being divided in up to a 12 module array at 560 MW (net). The small design of NuScale's plant makes it less expensive to build and operate, and safer than traditional nuclear plants. NuScale continues to work with the Department of Energy, Oregon State University, and other public and private regional, national, and international entities to move towards the construction of the first NuScale plant. Specifically, Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power Project (CFPP) is actively pursuing the development of a NuScale plant in Idaho.

As a member of NuScale's Advisory board, PGE will continue to gain knowledge about the development of this and other nuclear technology, as well as provide input on the development of NuScale's SMR. Additionally, should future, new nuclear technology gain public acceptance and economic viability in Oregon, PGE will once again model nuclear in its portfolios accordingly.

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[173] While Oregon law prohibits the siting of a nuclear facility, the law does not prohibit PGE from serving customers with nuclear energy. PGE notes that the Utah Associated Municipal Power System Carbon Free Power Project is currently working with NuScale to bring a nuclear facility to commercial operation in 2025. PGE will continue to monitor such developments and what benefits this type of resource (or others) may offer customers. (http://www.nuscalepower.com/our-technology/technology-validation/program-win/uamps)

[174] See http://www.nuscalepower.com/, retrieved on July 18, 2016.

7.4 Supply Resource Cost Summary

The analysis performed in this IRP considered those supply-side technology alternatives that are commercially available during PGE's Action Plan horizon (2017 through 2020) and compliant with all existing regulation. These are:

- Natural gas-fired: SCCTs, CCCTs, and reciprocating engines.
- Centralized renewable resources: biomass, geothermal, solar PV, and wind energy.

7.4.1 Expected Cost and Operating Parameters

PGE models new WECC resources in AURORAxmp, based on the construction and operating parameters, and capital and operating costs shown in Table 7-4. For modeling purposes, PGE assumes that wind and solar technologies can be online as soon as 2018. CCCTs, biomass, and geothermal require a longer duration from commencement of construction to commercial operation. For this reason, PGE assumes the online dates for these resources to be no sooner than 2021. As further discussed in Chapter 10, Modeling Methodology, PGE uses the Frame CT (7F.05) as the representative for generic capacity resources in portfolio analysis. PGE assumes these resources are available as early as 2018.

TABLE 7-4: New resource cost assumptions

IRP Modeling Assumptions (2016$)	New & Clean Nameplate (MW)	First COD Year	Economic Life (Years)	Expected Availability (%) [1]	Overnight Capital Cost ($/kW) [2,3]	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh) [4]	Degraded Heat Rate (BTU/kWh)
Binary Geothermal	35	2021	30	89%	$7,837	$0.26	$27.29	N/A
Biomass (Generic)	35	2021	30	87%	$5,849	$1.71	$9.49	13,350
Central Station Solar Tracking PV	103	2018	25	24%	$1,947	$10.20	$0.84	N/A
Wind Plant PNW	338	2018	27	34%	$1,667	$45.90	$0.84	N/A
Wind Plant Montana	236	2018	27	42%	$1,716	$45.90	$0.84	N/A
H-class CCCT 1x1	400	2021	35	95%	$1,071	$8.70	$2.65	6,503
Wärtsilä Reciprocating Engine	110	2021	30	96%	$1,442	$3.43	$9.11	8,437
GE 7F.05 SCCT 1x0	230	2018	30	98%	$621	$3.28	$9.48	9,981

1) Expected Availability is expected capacity factor for Wind and Solar PV; for other resources, it is capacity net of forced and planned outages.
2) Overnight capital corresponds to First COD Year; overnight capital costs are subject to the trajectory discussed below.
3) Overnight capital also includes OEFSC payments to Climate Trust of Oregon for natural gas-fired resources.
4) Variable O&M includes integration costs from PGE Renewable Energy Resource Integration Study.

The costs and operating parameters for these resources incorporate information provided by independent consultants, B&V[175] and DNV GL,[176] and the research, professional judgment, and

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[175] Appendix K, Characterization of Supply-Side Options (Black & Veatch), provides the B&V report.

[176] PGE contracted with DNV GL to provide technical and financial information on five potential renewable generation resources the Company could potentially model this IRP. DNV GL provided information on three wind projects and two generic solar projects. B&V provided cost and technology information on thermal renewables—geothermal and biomass. See Appendix M, Evaluation of Five Renewable Supply Options (DNV GL).

experience of PGE's technical staff. The B&V and the DNV GL reports provide detailed information on the resources listed in Table 7-4.

7.4.2 Potential for Future Cost Changes

Advances in technology are usually characterized by a combination of a decline in real cost per kW, due to learning effects and economies of scale, and an increase in conversion efficiency (i.e., a better heat rate) for thermal plants (or, alternatively, increases in wind energy capture and conversion efficiency for renewable resources) due to actual technology improvements.

The estimates from third-party consultants include outlooks on technology maturity and the potential for reductions in future capital costs. B&V and DNV G-L employed data developed by the United States Department of Energy's (DOE) Energy Information Administration's (EIA) 2014 Annual Energy Outlook (AEO) and applied these data to the present-day capital costs for each technology. For data developed for the 2014 AEO, the EIA employs the National Energy Modeling System (NEMS).[177]

Maintaining a constant dollar basis, the consultants developed a set of capital cost "forecast factors" for the next 20 years, and normalized these factors to 2015 values for each technology presented in the NEMS overnight capital cost data. Figure 7-11 reports the resulting technology learning curve.[178]

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[177] NEMS is a commonly used method for future capital cost forecasting. It provides technology-specific forecast for the majority of technologies of interests, and forecast data is provided on a year-by-year basis from 2015 to 2040. Within the model, future cost forecasts are developed and updated annually, rather than on cycles of multiple years (i.e., 2 to 5 years). See Appendix K, Characterization of Supply-Side Options (Black & Veatch).

[178] Appendix K, Characterization of Supply-Side Options (Black & Veatch), and Appendix M, Evaluation of Five Renewable Supply Options (DNV GL), provide additional discussion on the methodologies and assumptions used to estimate the forecast factors in the B&V and DNV GL reports.

FIGURE 7-11: Overnight capital cost learning curve by technology type

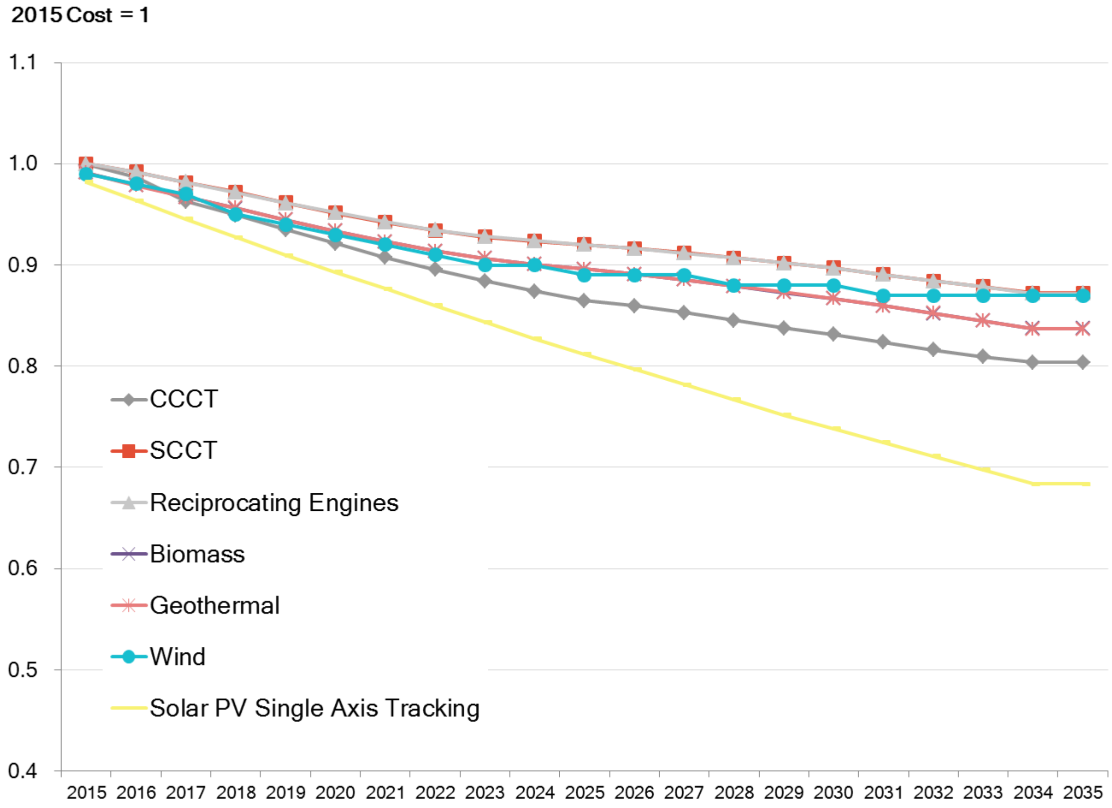


Figure 7-11 shows that all technologies modeled in this IRP have a forecasted declining overnight capital cost over time. More precisely:

- Solar technologies have the sharpest expected cost drop. Given a normalized cost of 1.0 in 2015, such costs decline to less than 0.70 by 2035, that is solar plants will be more than 30 percent cheaper in 2035 than in 2015 (in real dollars);
- CCCTs will be approximately 20 percent cheaper in 2035;
- All other technologies will be 10-15 percent cheaper by 2035.

While the overnight capital cost forecast factors in Figure 7-11 are representative of long-term trends, changes in supply-demand drivers for manufacturing inputs (e.g., steel, oil) and construction costs could result in different future outcomes. Technological improvement could be over- or under-stated and tax provisions can significantly impact the overall economics of building a given technology instead of another. To take into account such risks, PGE tests portfolios against futures in which capital costs may be higher or lower than the reference case. Chapter 10, Modeling Methodology, presents these futures.

7.5 New Resource Real-Levelized Costs

PGE adds the following costs to the capital and operating costs summarized in Table 7-4 to derive estimated real-levelized, fully-allocated energy costs for new generating resources available to the Company:

- Fuel;
- Fuel transportation;
- CO_2 emission costs;
- Tax credits; and,
- Transmission costs.

Capital costs include amounts for:

- Depreciation;
- Property tax;
- Return on capital; and,
- Income taxes.

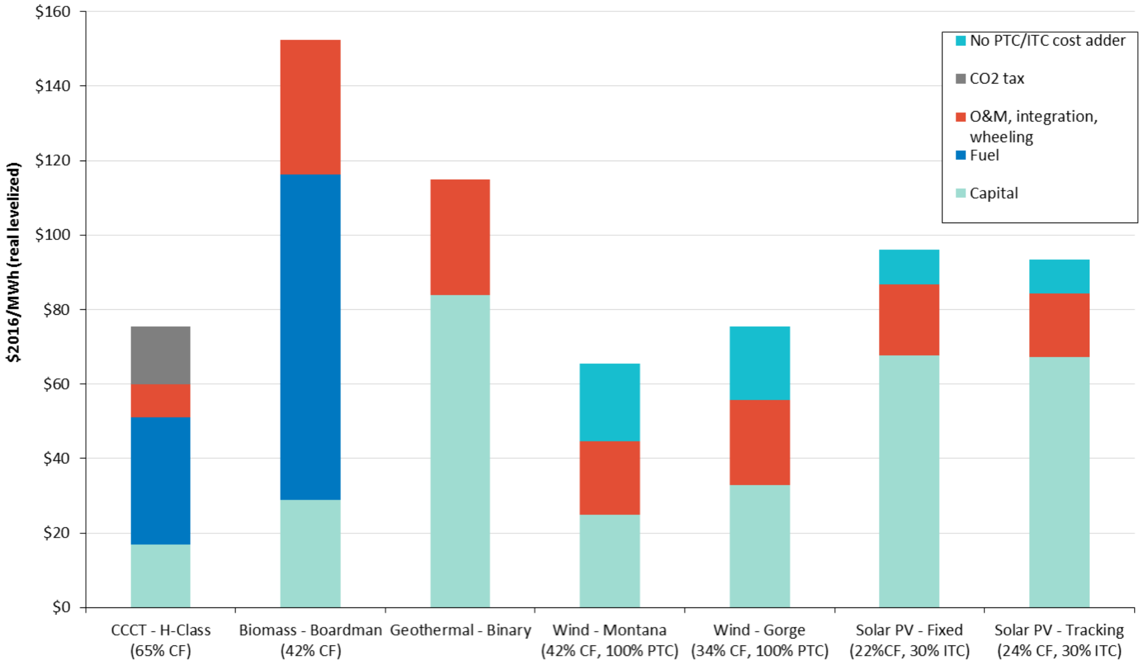
Chapter 10, Modeling Methodology, discusses the Company's financial assumptions.

Operating costs include fixed and variable O&M, transmission, and integration costs.

The analysis in this IRP does not attempt to estimate the cost of new transmission for Montana wind or any other resource modeled. Rather, PGE bases its cost assumptions for transmission service on published rates. As discussed above, and in Chapter 10, Modeling Methodology, eliminating the uncertainty regarding incremental transmission costs from the analysis provides the opportunity to estimate a potential budget for such costs by comparing the present value cost of two portfolios (one with and one without the remote resource).

To calculate a real-levelized cost of energy, PGE used a life-cycle revenue requirements model, in conjunction with the Company's production cost model AURORAxmp. PGE applied its incremental cost of capital and assumptions about plant book life and tax depreciation in making the calculations. Figure 7-12 shows the reference case total levelized costs of energy for PGE's primary supply-side resource alternatives.

FIGURE 7-12: Generic resources life-cycle levelized cost of energy ($/MWh)



O&M includes wheeling and integration.
Renewable resources reflect the current production tax credit (PTC) and investment tax credit (ITC) incentives at the level noted, consistent with current legislation. Effect of the tax credit is reported as a separate cost adder.
Costs assume Reference Case CO_2 tax beginning 2022.
Additional transmission investments to connect to BPA are not included in the estimates above.
CCCT - H-Class assumes a long-term average cacpacity factor of 65%.

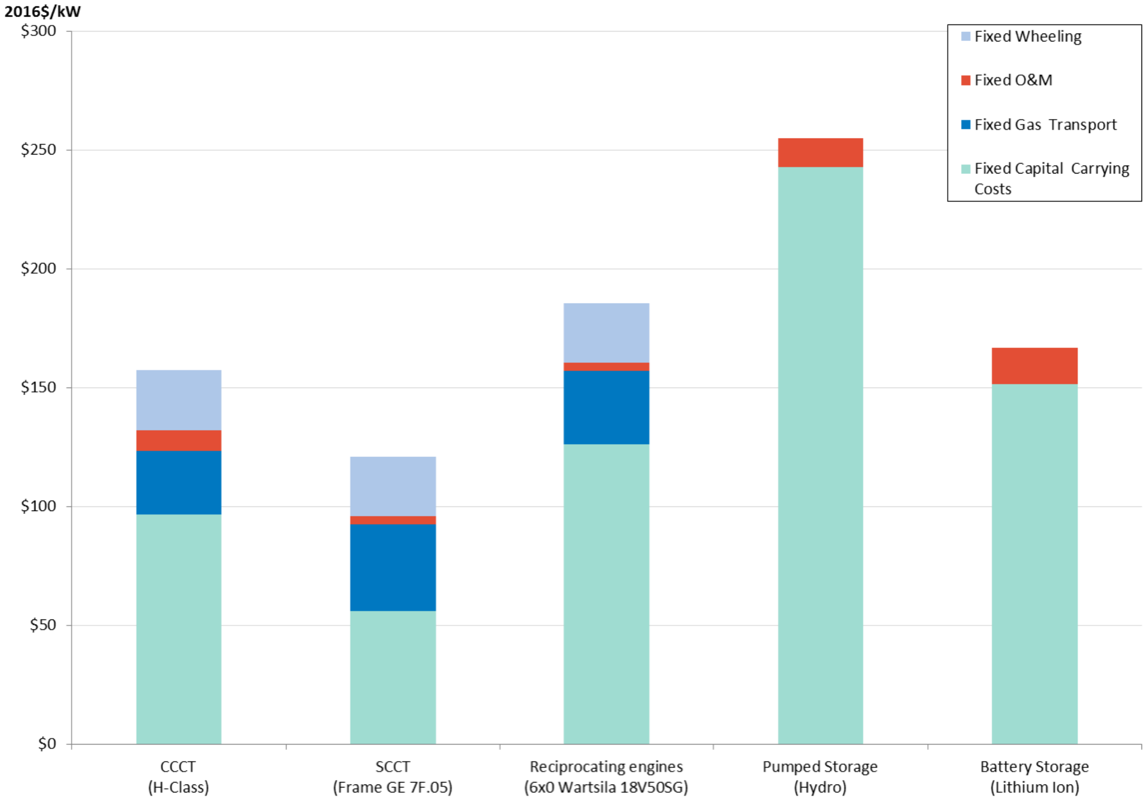
Figure 7-12 represents the real-levelized cost per MWh of energy produced, including both fixed and variable cost components. Biomass in the graph reflects the approximate costs of the Boardman project as included in the portfolio analysis. For this resource cost comparison, PGE includes the cost of the CCCT based on an assumed 65 percent capacity factor as representative of long-term economic dispatch.

Resources used primarily for flexibility and capacity, such as reciprocating engines, are not included in the graph above, as they are not typically utilized for providing continuous energy. Rather, Figure 7-13 illustrates the investment and fixed cost of resources capable of providing one kW of year-round capacity. The technologies capable of providing capacity all hours, year-round (except for unexpected outages), are those that are dispatchable: combustion turbines, reciprocating engines, and energy storage.

Figure 7-13 also shows that the cheapest capacity resource on a $ per kW basis is an SCCT, followed by a CCCT. Because of their least-cost, the frame SCCT is the technology selected to fill generic capacity needs in PGE's portfolio analysis. This is a simplifying modeling assumption and not a selective requirement in PGE’s resource procurement. In fact, the Company will consider all of the above-listed technologies in future competitive bidding processes. Please refer to further discussions of resource attributes in Chapter 5, Resource Adequacy, and Chapter 13, Action Plan.

Energy storage has been the focus of recent regulatory attention. For this reason, and because of storage's future prospects, PGE extensively studied this technology and provides its analysis in Chapter 8, Energy Storage. Although not a resource option used directly in PGE's final portfolio analysis for this IRP, the Company does include battery energy storage as a portfolio resource in an outboard model. Testing and improving modeling techniques for accurately evaluating energy storage remains a priority for PGE.

FIGURE 7-13: Generic resources life-cycle fixed revenue requirements ($/kW)



While the stand-alone costs for a given resource type are instructive, the resources become building blocks within portfolio analysis where PGE adds economic dispatch and risk analysis. Further, PGE's approach to portfolio construction calibrates all candidate portfolios to materially similar capacity and reliability levels. The only exception to this approach is the *RPS Wind 2018 + No Capacity Action* portfolio, which evaluates the cost and risk of not adding long-term resources beyond those needed to maintain physical compliance with Oregon RPS, but instead relying on shorter-term market purchases. PGE presents the details of the portfolio analysis in Chapter 10, Modeling Methodology, and Chapter 12, Modeling Results.

7.5.1 Sources and Assumptions for PGE Real-Levelized Costs

PGE applied the following key assumptions in estimating the reference case resource costs shown in Table 7-4:

- BPA wheeling rates of $1.79 per kW-month to grow annually at inflation, with annual real growth of approximately one percent over the analysis time period (2017-2050).
- PTC and ITC set for qualifying resources are based on current legislation. The credits amount to approximately $23 per MWh for the PTC (in 2016 dollars, the amount is adjusted annually for inflation), and the ITC is currently equivalent to 30 percent of eligible expenditures. As discussed in Chapter 3, Planning Environment, qualified plants that begin construction after 2016 have decreasing tax credits as illustrated in Table 7-5.

TABLE 7-5: Federal tax credits in IRP

Begin Construction (Year)	Production Tax Credit % of credit per MWh	Investment Tax Credit % Investment
2016	100%	30%
2017	80%	30%
2018	60%	30%
2019	40%	30%
2020	0%	26%
2021	0%	22%
2022-2050	0%	10%

7.5.1.1 Wind

- PGE includes two geographic locations for wind resources: Pacific Northwest (PNW), with a capacity factor of 34 percent, and Montana, with a capacity factor of 42 percent.
- DNV GL provided the information used as the basis for capital cost. DNV GL also provided information for new 338 MW and 236 MW wind resources. For portfolio construction, PGE assumes wind resources are scalable to meet projected energy needs.
- PGE incorporates PTC availability in this IRP pursuant to the assumptions provided in Table 7-5.
- O&M includes integration costs of approximately $0.83 per MWh in 2016 dollars, escalating at inflation.
- PGE provides no estimates for the incremental transmission costs for Montana wind. The IRP assumption is that transmission already exists and PGE can wheel generation from Montana to PGE with overall losses of 6.80 percent.

7.5.1.2 Central Station Solar PV

- PGE includes the estimated cost and operating parameters of a central station PV resource located in central Oregon, based on a ground-mount single-axis tracking configuration. The estimated capacity factor is 24.2 percent.
- DNV GL provided the assessment used as the basis for cost and performance estimates. Actual solar project costs may vary significantly depending on location, type of technology, and whether or not a tracking system is used.
- PGE incorporates ITC availability using the assumptions in Table 7-5.
- Integration costs of approximately $0.83 per MWh in 2016 dollars, escalating at inflation, are included in O&M.

7.5.1.3 Geothermal

- Costs are representative of a binary geothermal system.
- The consolidated Appropriations Act of 2016 did not extend the PTC for Geothermal resources beyond year-end 2016.
- Estimated capital costs include the cost of well development.
- Variable O&M costs estimated by B&V include costs associated with the development of one new supply well every five years; it is assumed that one out of every five replacement supply wells is dry (i.e., does not provide sufficient flow and is unusable), and well replacement costs include costs associated with the drilling of dry wells.

7.5.1.4 Biomass

- Costs provided for generic biomass projects are representative of a 35 MW steam turbine fueled with wood waste. Fuel cost is highly site-specific for biomass and its impact on the total cost per kWh could well exceed 50 percent.
- Because of the uncertainties surrounding a generic biomass project, PGE modeled the performance and cost parameters of the Boardman Biomass Project in the portfolio analysis for this IRP, as reported in Chapter 10, Modeling Methodology.
- Air quality control equipment includes selective catalytic reduction (SCR) systems for NO_X control, continued operation of sorbent injection for acid gas control, and a baghouse for particulate matter (PM) control.
- The Consolidated Appropriations Act of 2016 did not extend the PTC for Biomass resources beyond year-end 2016.

7.5.1.5 Natural Gas

- CCCT - GE H-series (7HA.01)
    - PGE estimates capital and operating costs based on a GE H-series combustion turbine (7HA.01) in combined cycle with no duct burner, providing generation capability of 400 MW new and clean.

    - Costs include a CO_2 offset payment to the Climate Trust of approximately $15 per kW, based on current requirements.
    - For portfolio construction, PGE assumes a CCCT natural gas plant is not scalable to meet the projected energy needs (i.e., a plant is added to the modeled portfolios in its entirety). Failing to do so, would assume joint ownership of a CCCT, with joint decision in its economic dispatch, which has proven challenging to pursue.
  - SCCT and Reciprocating Engines
    - PGE uses capital and operating costs from B&V for the GE 7F.05 (SCCT) and Wärtsilä reciprocating engines.
    - Costs include a CO_2 offset payment to the Climate Trust of approximately $27 per kW for the 7F.05 and the Wärtsilä reciprocating engines, based on current Oregon Energy Facility Siting Council (OEFSC) requirements.
    - For portfolio construction, PGE models the SCCT Frame 7F.05 as representative of a generic capacity resource. The Company assumes this technology to be scalable to exactly match the projected capacity needs.

7.6 Emerging Technology

Long-term resource planning requires that PGE give consideration to potential future sources of electrical generation. The emerging technology discussed in this section is not technologically or economically viable to meet the Company's current planning cycle needs, but may become a significant source of new supply in future IRPs.

The Company is particularly interested in looking for emerging technology that will help it comply with new environmental regulations and increased Oregon RPS targets.

7.6.1 Hydrokinetic Energy

Hydrokinetic energy is the production of energy from the movement of water – it can include ocean waves, tidal and currents, and in-stream energy production. Harvesting energy from waves can involve hydraulic, mechanical, and pneumatic generation. Tidal and ocean currents generate electrical energy by turning turbines installed under water. Hydrokinetic Energy Generators are usually free-standing, mechanical devices rotated by the flow of passing water. These devices can be open, three blade, horizontal axis rotors attached to a base; shrouded, multi-blade, horizontal axis turbine rotors, or an open, vertical axis, multi-cup rotor submerged in a river or canal.

Tidal In-Stream Energy Conversion (TISEC) is a term used to describe the conversion of the kinetic energy created by moving water into electrical energy. TISEC devices resemble wind turbines and provide efficient, reliable, and environmentally-friendly electrical energy. Currently, TISEC devices are not a viable option for meeting the demand for sustainable energy.

Oregon is a leader in the development of wave energy in the United States and is fast moving toward full-scale technology deployment. Efforts to further develop and deploy hydrokinetic energy generators along the Oregon Coast increased after the Oregon Land Conservation and Development Commission adopted amendments to the Oregon "Territorial Sea Plan" on January 24, 2013.[179] A critical amendment was the addition of a map designating potential areas for development of marine renewable energy. Northwest Energy Innovations deployed two half-scale buoys off the coast of Newport, Oregon, one in connection with the Northwest National Marine Renewable Energy Center (NNMREC).[180]

In 2008, NNMREC created the Pacific Marine Energy Center (PMEC). PMEC comprises a variety of scaled sites and test facilities, for testing wave and current converters. Currently, PMEC has research and testing facilities located in Oregon and Washington. The Oregon research, testing, and consulting services are on the Oregon State University campus in Corvallis, Oregon. PMEC's Oregon open water testing site—also known as PMEC North Energy Test Site (NETS)—is in Newport, Oregon. PMEC expects to have a second Newport testing site, PMEC South Energy Test Site (SETS), available for device testing sometime in 2017.

The Newport test sites allow for full-scale wave energy testing. Specifically, PMEC-NETS allows devices up to 100 kW to connect to Ocean Sentinel, an "instrumentation buoy [that] provides an electrical load and performs data acquisition for wave energy devices under test" at PMEC-NETS.[181]

FIGURE 7-14: Ocean Sentinel PMEC-NETS

The new PMEC-SETS will be a grid-connected site, accommodating centralized wave energy testing. PMEC-SETS has four testing berths, on which wave energy equipment is anchored and moored, with underwater cables capable of transmitting data to on-shore facilities, and ultimately power to the grid. NNMREC's Oregon facility and the Navy's Wave Energy Test Site (WETS) in Oahu, Hawaii, are the only grid-connected test sites in the United States.

PGE will continue to monitor the developments in hydrokinetic energy in Oregon and throughout the country, to determine when this potential source of power will be able to yield sufficient power to the grid at a reasonable cost to PGE customers.

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[179] The Oregon State Legislature also enacted ORS 757.811, which requires that "any regional transmission planning processes conducted for the transmission planning regions that wholly or partly encompass any areas of this state shall adequately consider the transmission of electricity from ocean renewable energy generated within Oregon's territorial sea."

[180] http://www.oregonbusinessplan.org/industry-clusters/about-oregons-industry-clusters/wave-energy/

[181] http://nnmrec.oregonstate.edu/resources-industry/open-ocean

7.7 Resource Ownership vs. Power Purchase Agreements

Guideline 13 of the OPUC's IRP requirements addresses resource acquisition. It requires an electric utility to:

- Identify its proposed acquisition strategy for each resource in its action plan.
- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

It is important to note that this guideline focuses specifically on resource acquisition considerations. The guidelines do not suggest attempting to distinguish between ownership and PPAs within the least cost/least risk portfolio modeling or Action Plan recommendations.

In this IRP, PGE is proposing the acquisition of new resources (ownership and/or PPAs) to replace Boardman and meet the Company's capacity need. However, the IRP can only provide generic descriptions of third-party ownership options, along with potential generic pros and cons of each option. The selection of a PPA resource or a utility-owned resource is situational, depending upon a number of factors including the particular characteristics of the project, the ability to raise financing, as well as the profile and circumstances of the seller and utility at the time of selection. Accordingly, PGE uses a comprehensive, objective approach to assess the risks and benefits of specific utility-owned and contracted resources.

PGE believes the competitive bidding process is the best place to address the question of ownership versus PPA. Because pricing and terms for PPAs are counterparty-, technology-, deal structure-, risk allocation-, duration-, and location-specific (and also subject to post-bid negotiations), the IRP cannot provide indicative pricing and risk differences between ownership and PPAs for consideration in trial portfolios. Indeed, the IRP is generally agnostic with respect to ownership structure and instead focuses on the inherent cost and performance attributes of the generating asset, and how that asset will meet needs and address risk within the broader generation portfolio (e.g., resource type and fuel diversification considerations).

In the following sections, PGE discusses the risks and benefits associated with resource ownership, as well as PPAs and tolling agreements, the two primary market alternatives for mid- and long-term contracts for wholesale electricity today. This section also provides a brief summary of relevant modifications to the Competitive Bidding Guidelines in recent years.

7.7.1 Benefits of Utility Resource Ownership

The following sections discuss the benefits of utility resource ownership.

7.7.1.1 Synergies with Existing Resources

An ownership option may allow the utility to use existing locations and infrastructure, which can save costs and minimize the footprint of a new generating project. For example, PGE built the Port Westward Unit 2 project at the existing Port Westward site, and the project did not require new roads or other infrastructure other than the new plant and some minimal appurtenant facilities. Moreover, using a PGE-owned site increases the likelihood that PGE has already considered potential costs and issues, such as transmission line upgrades, fuel transport upgrades, and environmental constraints.

Through experience developing, owning, and operating facilities, PGE has demonstrated its ability to mitigate the risks and manage the costs of resource ownership across all technologies and fuel types, and across multiple projects of significant size, scope, and complexity.

Ownership allows the utility to maintain operational control over an asset and determine how best to integrate an asset into its fleet. Operational control also permits the utility to integrate a resource in a manner that maximizes the value of the resource to customers and the utility.

7.7.1.2 Financing

Utilities, including PGE, generally maintain relatively low debt to total capital ratios, and strong credit ratings. As a result, utilities may be in a better position to raise capital to develop and construct a project in the near- to mid-term. The ability to raise capital at a reasonable cost provides increased certainty that, once a utility identifies a good resource, the development will go forward to completion. In contrast, independent power producers (IPPs) are more vulnerable to market turmoil and changing regulatory policies, often making it more difficult for them to secure capital at a reasonable cost—creating uncertainty around an IPP's ability to complete a project. Moreover, even when IPPs are able to secure capital at a cost competitive with a utility-backed PPA, it is generally because the utility’s credit is backing the agreement, thus reinforcing the greater certainty provided by utility financing.

7.7.1.3 Cost of Credit

In response to the energy crisis of the early 2000s, and reinforced by the recent turmoil in the financial markets, most long-term PPAs come with an imputed debt component and margin requirement costs. Some credit rating agencies measure and report imputed debt to reflect the future cash flow commitment of the buyer as if it were debt. PGE believes a debt equivalence metric is critical, because credit rating agencies are able to compare the risk of default for different companies normalized for their choices to build or enter into a PPA. As a result, PPAs reduce PGE’s financial flexibility or increase the Company’s borrowing costs.

Margin requirements are a standard feature within most fixed price PPAs. This feature serves to protect both the buyer and the seller from the likelihood of default when market prices move materially from the negotiated fixed price of the PPA. If market prices move up from the negotiated fixed price, the buyer is exposed to higher costs for replacing the energy if the seller defaults, while the seller could default on the lower fixed price contract in order to sell that energy into a higher-priced market. In this case, the margin requirement clause would require the seller to post a cash collateral or letter of credit to the buyer and vice versa if market prices move down. Both imputed debt and margin requirements further tip the scale in favor of ownership to the detriment of PPAs. PPAs will solely add to the liability side of PGE’s Balance Sheet without any of the benefits of ownership, thus artificially raising PGE’s cost of debt.

7.7.1.4 Long-Term Access to Resources

Utility ownership provides long-term access to generation resources, which provides important risk mitigation for utility customers. For instance, much of the value associated with renewable energy generation projects uniquely ties to ownership and the specific project location. In the case of wind or solar resources, prime sites undergo development first, and resource owners often select these sites based upon site-specific factors, such as wind speed, which is critical to the value of the resource. If a utility purchased power from an IPP, who owned one or more of these prime sites, and the IPP did not want to extend the agreement upon expiration or sell the resource to the utility, the utility would have to seek out another resource. It is unlikely that the utility would be able to find a comparable wind or solar resource (or site) offering similar value to customers. Utility ownership mitigates this risk by allowing the utility to maintain long-term access to prime sites and valuable generation resources for customers.

An ownership option provides the utility the opportunity to:

- make life extension improvements;
- use the site for additional resources in the future;
- efficiently address plant modifications (required as a result of changes in state and federal laws and regulations); and,
- pass on to its customers the benefits of these opportunities.

While a utility could potentially obtain some long-term access through negotiated extension rights in a PPA, a utility-owned project clearly provides this benefit. A competitive solicitation affords counter-parties the opportunity to offer extension rights, which will be valued—as appropriate—for such benefits.

7.7.2 Risks Associated with Utility Ownership

Ownership options have some associated risks. Owning a plant potentially exposes the utility and customers to the following risks:

- The cost of ownership and operation exceed available market-priced alternatives;
- The cost of poor project performance or early retirement; and,
- The unknown liabilities associated with reclamation at the end of the project life.

Project performance risk is usually mitigated through equipment selection and siting;[182] a well-developed and managed engineering, procurement and construction plan prior to commercial operation; plant operator experience and knowledge; maintenance plans; and management of the relationship with local distribution and transmission system operators. A utility can also minimize energy output risks to it and its customers by negotiating: 1) effective performance guarantees; and 2) warranty and maintenance provisions in the turbine supply agreements and/or engineering, procurement and construction agreements.

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[182] Most IPPs include abandonment costs in their long-term PPA, and in the final analysis, the utility and its customers pay those unknown costs as well.

While such provisions may also be available in a PPA, an ownership option provides better control and oversight of all of the above-described factors. Under a PPA, the utility and its customers may not receive any of the savings that result from management of the project. In the case of contract resources, utility customers also do not receive any of the value associated with a project after the expiration of the contract (e.g., site lease renewals, generation repowering, or capital additions to extend the project life).

7.7.3 Power Purchase Agreements

PPAs are contracts (three to 25 years) requiring one party to provide physical power to another party, in this case PGE. They have a variety of terms and conditions, which typically fall into a few basic categories: 1) firm or unit-contingent power delivery, 2) fixed or index price, and 3) delivery location (at PGE system, generation plant bus bar, or at a market hub such as Mid-Columbia). PGE typically executes PPAs pursuant to the Western Systems Power Pool (WSPP) Schedule C, under which sellers must deliver the energy at the contracted price. In case of seller default, the seller may owe liquidated damages to the buyer.

PPAs offer multiple options to PGE and its customers:

- **Diverse Portfolio.** PPAs may add diversity to PGE’s overall supply portfolio. This diversity can be in the type of resources, terms and pricing options, levels of flexibility in resource delivery, and the types and terms of ownership involved with a PPA.
- **Construction Risk.** Under the terms of many PPAs, the power producer bears the risk associated with construction of the project. This assumption of risk reduces a risk generally assumed by a utility and its customers.
- **Operating Risk.** Independent power suppliers generally bear the operating risks associated with the power project, particularly if the resource does not meet specific availability and/or heat rate targets.
- **Technology Risk.** PPAs temper PGE’s exposure to technology risks and stranded assets.

As noted above, PPAs also expose utilities and customers to numerous risks, including but not limited to: 1) the impact of debt imputation on PGE’s creditworthiness and borrowing costs; 2) unknown contract costs, such as abandonment costs; 3) lost benefits associated with contract expiration; and 4) the exposure created by the power supplier's default on the contract due to lack of financing or other reasons.

7.7.4 Tolling Agreements

Tolling agreements are typically take-and-pay contracts where the buyer pays a fixed demand payment or option premium for the right to receive energy or dispatch a plant. When the buyer exercises these demand rights, the buyer must make an additional payment for the fuel and/or operating expense to generate electricity. The buyer typically pays the demand payment on a monthly basis.

Tolling agreements can have a financial fuel index or a physical delivered fuel clause. The former allows simplified accounting and administration of the contract, whereas the latter may involve acquisition, delivery logistics, and nomination of fuel to the generator associated with the contract.

Additional terms in a tolling agreement may include O&M charges, start-up charges, limits on the number of start-ups per year, transmission charges, etc. Further, this type of contract can have other features, mentioned above for a PPA, such as unit availability and point of delivery.

7.7.5 Competitive Bidding Guidelines and the Procurement Process

In recent years, the Commission has opened a number of dockets pertaining to the Competitive Bidding Guidelines and addressing the ownership versus PPA issue.[183] Because the IRP makes no recommendation as to ownership structures for its identified resource needs, PGE believes that the competitive bidding dockets are the appropriate place to address the issue. Further, PGE believes a robustly designed RFP will take full advantage of the numerous resource alternatives available in a competitive market, allowing the Company to seek out and deploy all resources that will bring the best value for customers. As PGE considers future resource acquisitions, the Company will objectively weigh the benefits and risks of the various ownership options, in light of the bids received during the RFP process, and ensure compliance with the Commission's Competitive Bidding Guidelines.

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[183] See *In the Matter of an Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 14-149 (Apr. 30, 2014); see also *In the Matter of Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, opened May 20, 2016; and *In the Matter of an Investigation of Competitive Bidding Guidelines Related to Senate Bill 1547*, Docket No. UM 1776, opened May 20, 2016.

CHAPTER 8. Energy Storage

Energy storage resources are receiving increased attention as higher penetrations of renewables put new demands on the grid and battery technology costs continue to decline. This chapter presents an overview of PGE's actions to date regarding energy storage, including ongoing energy storage demonstration projects like the Salem Smart Power Center (SSPC), preparations for compliance with Oregon's energy storage legislative mandate (HB 2193), and progress toward developing an evaluation framework for future energy storage procurement decisions.

Chapter Highlights

- ★ **Energy storage resources have the potential to provide valuable services to the PGE system over a wide range of timescales.**
- ★ **PGE has begun evaluation of procurement options to comply with HB 2193, which requires 5 MWh of energy storage by 2020.**
- ★ **PGE is also developing an evaluation framework that the Company can apply to future energy storage procurement decisions. An initial energy storage analysis in this IRP aims to incorporate the key benefits that energy storage provides to the PGE system and to identify critical analytical capabilities that PGE will need for future IRPs and resource decisions.**

8.1 Technology

The **duration** of an energy storage system is defined as the time that it takes to discharge the device from the maximum amount of stored energy to the minimum amount of stored energy, if it discharges continuously at its rated capacity.

Example: A battery system can discharge at a rate up to 100 MW and can store up to 400 MWh (neglecting losses). If the battery begins with 400 MWh of stored energy, it can discharge for 4 hours before it runs out of energy. This system has a 4-hour duration.

Energy storage resources provide the ability to more efficiently meet demand with generation by shifting both demand and generation in time. This capability has the potential to reduce costs associated with load and renewable variability and unpredictability, as well as thermal plant and transmission operating constraints. To this end, several storage technologies are currently under development and in commercialization phases, each with unique operating characteristics, costs, and benefits to the system.

Most commercial storage technologies fall within three categories:

1. **Chemical storage**, which includes battery, flow battery, and by some definitions, fuel production technologies;
2. **Mechanical storage**, including pumped hydro storage, compressed air energy storage (CAES), and flywheels; and
3. **Thermal storage**, which typically involves the ability to store heat in a fluid or to shift thermal processes in time.

Within each category, the timescales, over which storage resources can provide energy and flexibility, help to differentiate the resources. Short-duration storage devices typically provide fast ramping capability over short timescales to supply ancillary services like frequency response and regulation. In contrast, longer duration devices are capable of storing excess energy during low cost hours for dispatch during more costly hours and contributing to resource adequacy by serving peak demand. While many long duration storage technologies can serve short duration use categories, the converse is rarely true. Most storage devices can provide services over multiple timescales and must optimize dispatch in order to maximize the total benefits across all services or use cases, taking into consideration device operating limits, system requirements, and market conditions.

Figure 8-1 summarizes several of the use cases under consideration by PGE. It also shows the timescales of response required to provide those services, while Figure 8-2 summarizes various storage technologies in terms of their response.

FIGURE 8-1: Use cases under consideration by PGE and their relevant timescales

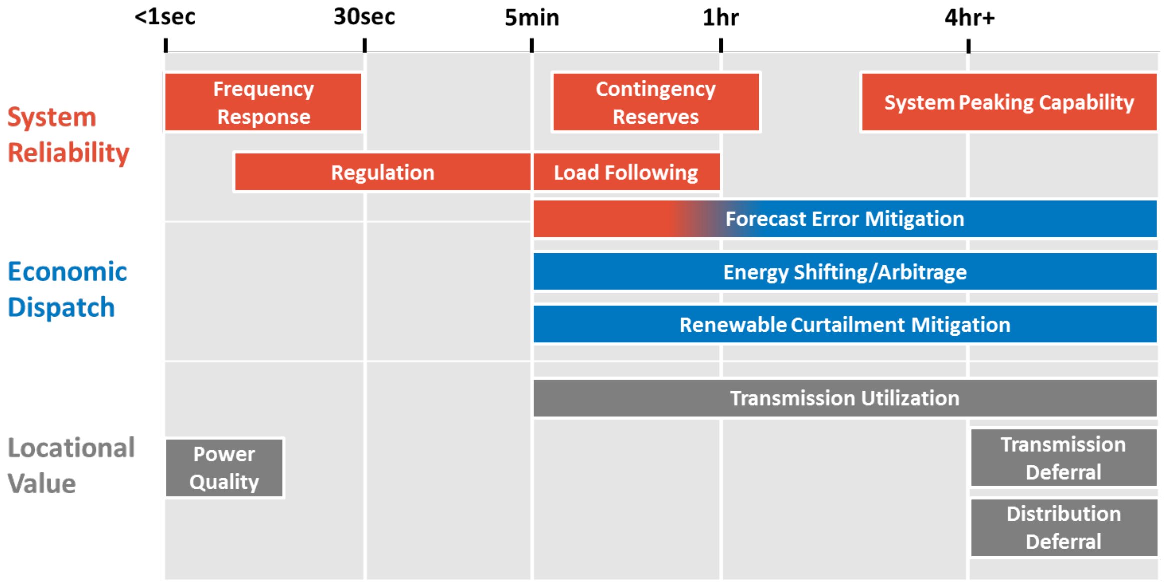
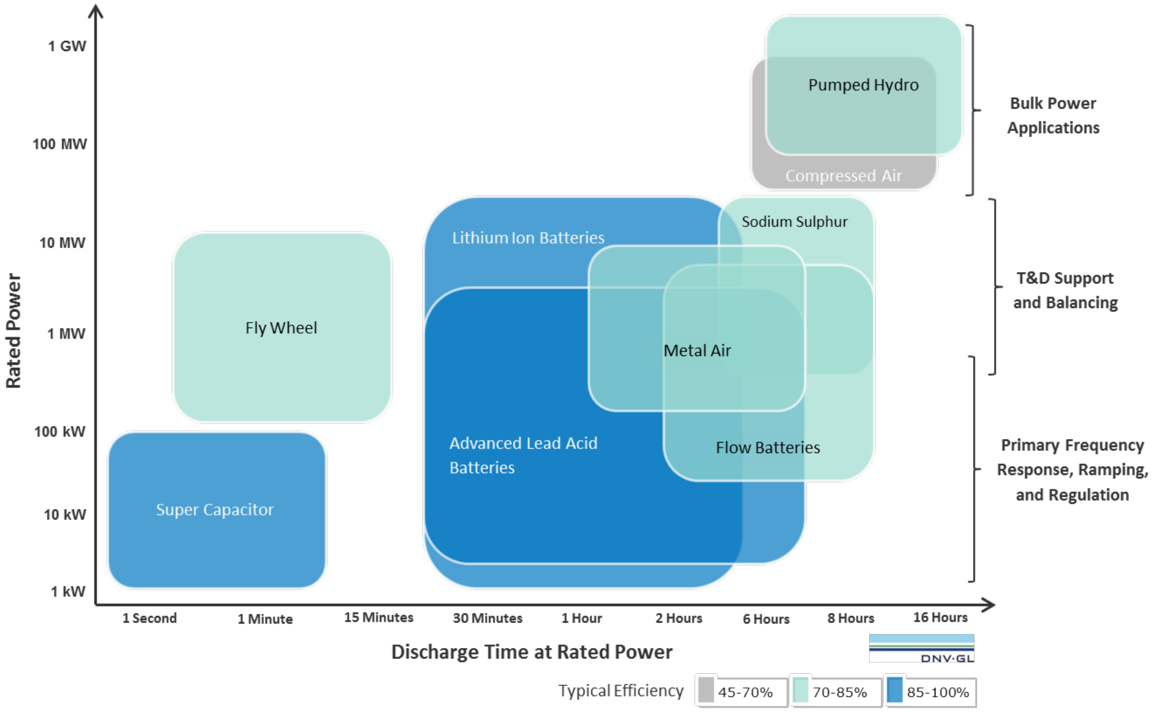


FIGURE 8-2: Timescales and grid services associated with various storage technologies



Source: DNV GL.

8.2 Legislative Mandate & Regulatory Environment

In 2015, the Oregon legislature passed House Bill 2193 (HB 2193), creating an energy storage mandate for Oregon's two largest electric utilities. HB 2193 requires PGE and PacifiCorp to each independently procure a minimum of 5 MWh of new energy storage on or before January 1, 2020. The maximum power capacity of this mandate is up to one percent of 2014 peak load or about 40 MW for PGE. The legislation directed the OPUC to adopt guidelines no later than January 1, 2017, for electric companies to use in submitting project proposals.

In developing the guidelines, the legislation instructed the OPUC to explore a number of key learnings and the potential value of applying energy storage system technology, including:

- Deferred investment in generation, transmission or distribution of electricity;
- Reduced need for additional generation during times of peak demand;
- Improved integration of different types of renewable resources;
- Reduced greenhouse gas emissions;
- Improved reliability of electrical transmission or distribution systems;
- Reduced portfolio variable power costs; or
- Any other value reasonably related to the application of energy storage system technology.

In response to the legislation, the OPUC opened docket UM 1751 in late 2015 and began conducting workshops to establish project proposal guidelines.

8.3 Experiences in Other Jurisdictions

In other jurisdictions, legislative mandates and electricity market design have driven energy storage development. For example, a mandate in California requires the three investor-owned utilities to procure a combined 1,325 MW of energy storage by 2020. In Southern California, utilities have procured battery and thermal storage systems, in part to meet this mandate and, in part, to meet local capacity reliability requirements. In contrast, in PJM, where the market incorporates performance-based payments for providing frequency regulation, market design has largely driven storage development.

While the benefits of energy storage are unique to each system or market, the progress to date in other parts of the country highlights the importance of continued evaluation of the benefits of energy storage to PGE customers. The following sections describe PGE's actions to date with respect to energy storage demonstration projects and efforts to develop an analysis framework and evaluation tools appropriate for PGE's system within the context of the Pacific Northwest region.

8.4 PGE's Actions and Objectives

In 2009, PGE initiated its 5 MW (1.25 MWh) Salem Smart Power Center (SSPC) project as part of the Pacific Northwest Smart Grid Demonstration initiative funded through the United States Department of Energy. The project demonstrated PGE's ability to develop a system capable of various use cases including: mitigating peak demand, integrating grid connected distributed standby generators, balancing renewables and responding to a transactive price signal.

Following PGE's commitment to the US DOE, PGE began exploring additional ways to exploit energy storage to address a wide set of use cases. One of the first use cases tested was the development of an algorithm that would allow SSPC to respond to frequency events. In early 2015, during such an event, PGE's batteries immediately responded, discharging 5 MW onto the grid to help recover grid frequency. The integration of a customer's solar array with the SSPC enabled PGE to demonstrate the value of energy storage in the integration of renewables on to the grid.

In collaboration with Portland State University, PGE is also exploring the use of an aqueous Na-Ion battery that seeks to provide a low-cost, 6-to-8 hour storage solution. In June 2016, PGE demonstrated the use of this battery at a customer's home to provide backup power during a grid outage. When not used for backup power, the battery will serve as a demand response resource.

HB 2193 provides an opportunity for PGE to extend its learnings beyond the SSPC project and these research activities. In the first three OPUC workshops, PGE, PacifiCorp, and other industry experts shared their respective views on energy storage, use cases, including value streams and a plan for how the utilities are likely to value energy storage beyond the legislative mandate. By January 1, 2017, PGE expects the OPUC to finalize project proposal guidelines, and then the Company will have 12 months to bring forth a project proposal.

In parallel with the OPUC's development of guidelines, PGE is working with outside consultants to analyze the various value streams of energy storage systems. PGE also issued a request for information (RFI) to solicit further insight from a wide array of vendors, manufacturers, and developers of energy storage. The Company is conducting face-to-face meetings with respondents throughout 2016 to aid in the development of PGE project proposals for HB 2193 or other energy storage resource acquisitions.

The Company is also actively engaged in developing methodologies for evaluating a range of storage technologies in response to both HB 2193 and the anticipated challenges in integrating renewable resources to comply with SB 1547. The following sections describe these efforts.

8.4.1 Quantifying Potential Benefits

PGE is developing an economic evaluation framework for energy storage resources that consists of five key classes of value streams:

- Energy shifting and arbitrage;
- Ancillary services;
- Avoided renewable curtailment;
- System peaking or capacity value; and
- Locational value.

While PGE describes each value stream individually, it is important to note that the capability to simultaneously provide multiple benefits is limited. The ability of an energy storage system to provide each benefit will depend on how PGE operates the system and prioritizes the benefit relative to the others in terms of value to the system. In this way, PGE's framework considers energy storage benefits to be "staggered," rather than "stacked."

8.4.1.1 Energy Shifting and Arbitrage

Energy storage resources in other jurisdictions have enabled utilities to time shift energy purchases (or to arbitrage) between peak and off-peak hours to reduce the cost of meeting the load as it fluctuates over time. With increasing renewable resources on the system, PGE anticipates price volatility to increase as the net load (load minus renewables) becomes more variable. In other parts of the West, analysts anticipate rapid solar development will depress daytime prices and drive increased prices in shoulder hours, leading to new opportunities for diurnal storage devices that charge during the day and discharge to help meet the evening peak as the sun sets. For the PGE system, price volatility between high and low renewable output events may be less predictable because of the region's higher reliance on wind resources.

Storage also has the potential to shift dispatch from more expensive peaking plants to lower cost thermal plants to realize reductions in fuel use and variable operations and maintenance (O&M) costs, avoid thermal unit starts, and reduce cycling burden. The balance of priority between these internally realized cost reductions and the net revenues associated with a storage resource interacting with a market are highly dependent on the utility and the specific controls utilized for the storage device.

8.4.1.2 Ancillary Services

Energy storage systems can also provide regulation (both up and down), frequency response, and contingency reserves to the system. Using energy storage devices to provide ancillary services reduces the burden placed on thermal generators to provide ancillary services, allowing them to operate at more efficient set points. While PGE is investigating the impact of additional renewable resources on the need for regulation, frequency response, and contingency reserve requirements, it is widely accepted that higher renewable penetrations will drive increased variability over very short time-scales, which may increase the need for reserve products, specifically regulation reserves.[184] In addition to this increased need for ancillary services, renewables introduce the additional challenge of meeting ancillary service requirements with fewer conventional generators online during hours with high renewable output. Both of these factors contribute to potential cost increases associated with relying on thermal resources to integrate higher levels of renewables on to the system. Providing a portion of these ancillary services with energy storage resources has the potential to reduce power costs.

In addition to regulation, frequency response, and contingency reserves, renewable integration analyses have identified an increased need for load following reserves under higher renewable penetrations. These reserves may be held in anticipation of forecast errors and sub-hourly fluctuations in net load on timescales down to five minutes. Similar to regulation reserves, providing load following reserves with thermal generation requires plants to operate at less efficient set points, which increases power costs. Energy storage resources may contribute to reducing these renewable

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[184] Renewable integration analyses typically incorporate larger regulation requirements to account for 1-min renewable output fluctuations, but maintain the frequency response and contingency reserve constraints applicable to today's systems.

integration costs by reducing the reliance on thermal plants to accommodate forecast errors and sub-hourly fluctuations.

8.4.1.3 Avoided Renewable Curtailment

At higher renewable penetrations, PGE has also identified the potential for events in which the system cannot fully accommodate high renewable output due to a combination of low load conditions, high hydro conditions, flexibility constraints on conventional generators, and the need to maintain minimum levels of conventional generation on the system to provide the ancillary services described above. Section 5.3, Flexible Capacity, further discusses these operational considerations. Energy storage systems have the potential to absorb excess generation during curtailment events, reducing the cost of meeting the Company's renewable energy targets.

8.4.1.4 System Peaking Value

Long duration energy storage systems can provide value to a system by dispatching during peak load conditions, reducing the amount of conventional capacity required to meet resource adequacy obligations. Since the ability of a storage resource to provide capacity during a potential shortage will depend on its state-of-charge (SOC) prior to the event, some have proposed an ELCC methodology similar to that applied to renewable resources to approximate the capacity contribution of storage devices.[185] In lieu of a standard methodology, some jurisdictions have simply applied a minimum duration constraint for counting energy storage resources toward capacity adequacy. For example, in California, resources must be capable of running for four hours over three consecutive days to qualify for resource adequacy payments. As a result, Southern California Edison used a four-hour duration as a proxy for this capability in its recent Local Capacity Requirements (LCR) RFO.

The **state of charge (SOC)** of an energy storage system is the amount of energy stored in the system at a given point in time. This terminology can be used across technologies, but typically refers to a battery system.

8.4.1.5 Locational Value

If sited and operated to specifically defer investment in transmission or distribution upgrades, energy storage may also provide locational value to the system. Similarly, the incorporation of energy storage into a Remedial Action Scheme (RAS) could support transmission reliability. These locational benefits require assessment on a site-by-site basis and may impact the ability of storage systems to provide other operational benefits.

8.4.1.6 Other Use Cases and Business Models

Use cases beyond those described above may provide opportunity to otherwise increase value to customers. For example, the ability to provide backup power during outages represents an important

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[185] See Chapter 5, Resource Adequacy, for more information about PGE's ELCC methodology.

customer value stream, especially if the device can also provide the system-level benefits described above during normal operations.

8.4.2 Operationalizing Potential Benefits

To provide the greatest value to the system, the operation of each energy storage system (or aggregation of energy storage systems) must occur in a way that optimizes across all value streams with consideration of how the battery dispatch interacts with the dispatch of the full PGE resource portfolio. Such optimization must take into consideration the operating constraints of the storage system and clearly respect the staggered versus stacked nature of energy storage use cases. In many hours, this will result in a storage device providing some combination of energy and ancillary services. In evaluating energy storage resource benefits, PGE assumes centralized control of the devices in coordination with the commitment and dispatch of other resources in the PGE fleet in order to maximize the value to the system across all of the benefit streams. The resulting dispatch and identified operational value may therefore vary from studies in other jurisdictions in which battery systems are modeled as price takers within organized energy and ancillary service markets.

Finally, the cost-effectiveness of energy storage systems will depend not only on the value of the benefits described here, but also the costs associated with building, integrating, and operating the systems. As both renewable integration challenges grow and technology costs drop, PGE anticipates that energy storage systems will eventually be part of a cost-effective strategy for meeting the Company's renewable, flexibility, and capacity needs. However, considerable uncertainty surrounds both the cost and value trajectories into the future as technological advancement is difficult to predict and renewable development and market evolution across the West promises to shift operational paradigms. For these reasons, evaluation of energy storage resources will be ongoing and will incorporate the latest information regarding operational needs, technological advancement, and technology cost reductions.

8.5 Treatment in IRP

In Order No. 14-415, the OPUC directed PGE to consider storage in its portfolio analysis in this IRP[186] . The economic evaluation of energy storage remains a rich area of research and full evaluation of storage devices within the IRP portfolio analysis framework remains challenging. In developing an initial evaluation methodology, PGE sought to capture the value streams most critical to a generic (i.e., location non-specific) storage device on the PGE system, including operational benefits (e.g., energy shifting and arbitrage, ancillary services, and avoided curtailment) and system peaking or capacity value. Figure 8-3 highlights the values captured within the IRP analysis and the subsequent section discusses the methodology.

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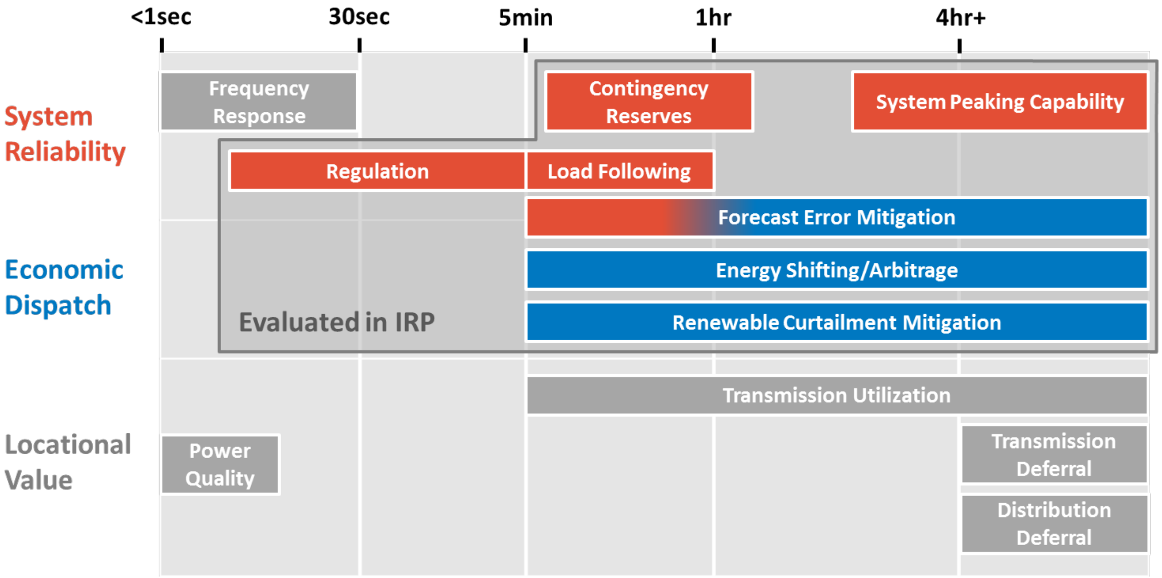
[186] OPUC Order No. 14-415, at 6.

FIGURE 8-3: Energy storage value streams evaluated in the IRP



8.5.1 Methodology

The primary challenge in accounting for storage systems in the IRP is that much of the value of energy storage resources is associated with very short timescale behavior that is not resolved by models that seek to characterize electricity system behavior and economics over several years and across a range of potential futures. Full consideration of an energy storage device and the value it brings to a system requires detailed modeling of complex operational constraints, representation of reserve requirements, and high resolution characterization of renewable integration challenges, all of which dramatically increases computation time and limits the scope of the analysis in time and across futures. The methodology described below focuses on battery storage behavior and value in a single test year (2021). The storage analysis specifically focuses on answering the following questions:

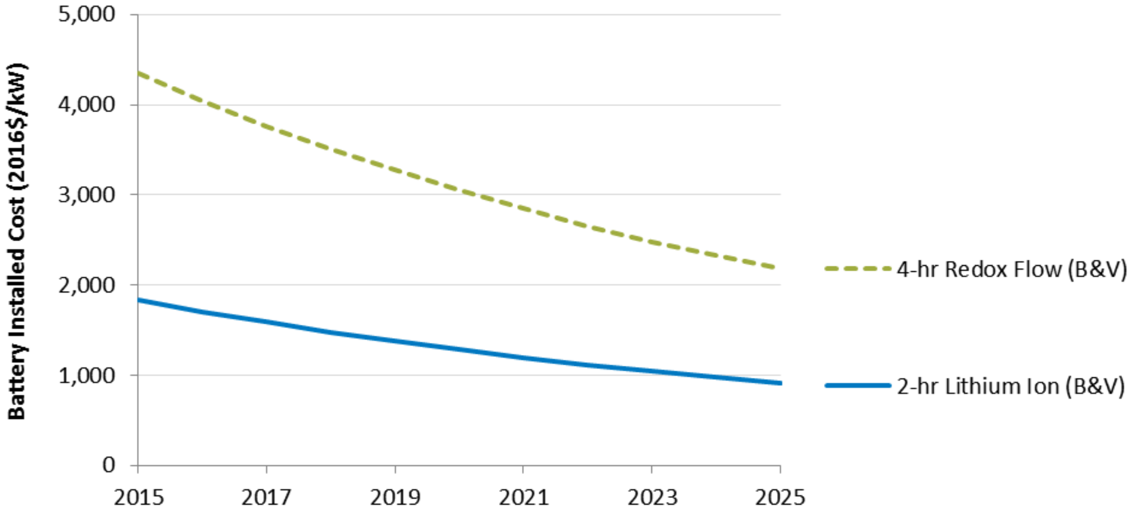
- How is a battery system anticipated to behave in the PGE fleet if operated to maximize value to the system?
- What are the primary use cases provided by a battery system, if operated in this manner?
- What is the total operational value provided by a battery system?
- Does the identified operational and capacity value of a battery system in 2021 relative to its cost warrant full incorporation into the IRP portfolio analysis at this time?

While the 2021 analysis provides preliminary insights into these questions, PGE acknowledges that findings may vary over time and across renewable portfolios, conventional resource portfolios, battery configurations, and market conditions. Therefore, this analysis is preliminary and investigative. PGE will continue to evaluate the economics of battery systems and other storage resources as additional data becomes available.

8.5.1.1 Resource Cost

PGE obtained resource cost estimates for a 2-hour lithium ion battery system and a 4-hour redox flow battery system from Black & Veatch as part of the independent analysis described in Chapter 7, Supply Options, and summarized in Appendix K, Characterization of Supply-Side Options (Black & Veatch) (see also Figure 8-4). PGE used an Excel-based revenue requirement model to determine the $/kW-yr fixed cost impact of each battery system with an assumed commercial online date of 2021.

FIGURE 8-4: Battery installed costs by COD year from Black & Veatch



8.5.1.2 Operational Value

To capture operational value streams, PGE relied on the Resource Optimization Model (ROM), which the Company originally designed to quantify operational challenges and costs associated with renewable integration. Because of this history, ROM already incorporates the key features required for energy storage evaluation: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons with forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch. More information about ROM is available in the discussion of the Variable Renewable Integration Cost in Chapter 7, Supply Options.

In each ROM simulation, the battery system was dispatched with PGE's full resource portfolio in order to minimize the net cost of meeting demand in each time step while also meeting several ancillary service requirements across the system. In addition to shifting energy through charging and discharging cycles, the simulated battery systems were able to provide: contingency reserves (spinning and non-spinning); upward and downward regulation reserves, which are held to accommodate fluctuations on timescales shorter than five minutes; and upward and downward load following reserves to meet flexibility requirements on timescales between five minutes and one hour.[187] Operation of the battery system was subject to constraints on maximum charging and

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[187] While reserve requirements approximate the need for flexibility on very short time scales, ROM does not currently explicitly resolve time scales shorter than 15 minutes.

discharging levels as well as a maximum SOC constraint to reflect the duration of the battery. Losses were incurred upon both charging and discharging. The operational value was determined by comparing PGE's total annual simulated operating costs in the test year with and without the battery system. This approach ensures that identified operational value is net of any variable costs associated with operating the battery. Importantly, this operational value assumes that PGE operates the battery system (or fleet) specifically to avoid operational costs across the PGE fleet and to maximize revenues in the market – alternative operational strategies would necessarily yield lower operational benefits.

8.5.1.3 Locational Value

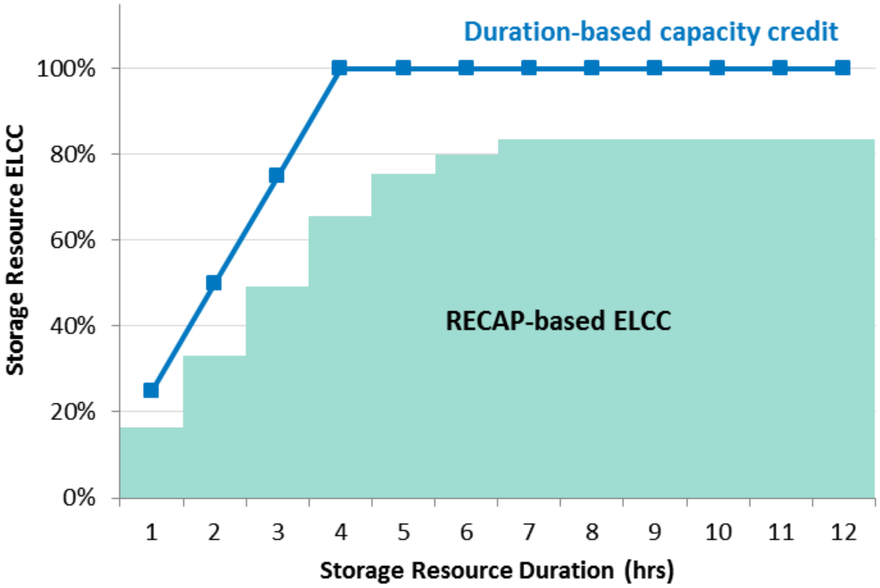
While PGE acknowledges that specific energy storage resources may provide additional benefits to the grid through transmission or distribution investment deferral, the IRP considers a generic energy storage device without specific locational information. Each storage resource therefore receives zero locational value for the purposes of this analysis.

8.5.1.4 System Peaking or Capacity Value

PGE used two preliminary methodologies to quantify the capacity contribution of each battery system: a duration-based methodology and an ELCC-based methodology. The duration-based methodology draws inspiration from practices in other jurisdictions, in which battery systems that meet a minimum duration requirement can count toward resource adequacy requirements. In CAISO, for example, battery systems must be capable of discharging for four hours to provide reliable capacity to the system. PGE’s duration-based methodology assumes that a battery system that PGE controls can provide peaking capability at the maximum discharge level that the battery system can sustain for a four-hour period. For example, a 50 MW 4-hr battery system has a capacity contribution of 50 MW or 100% while a 50 MW 2-hr battery system has a capacity contribution of 25 MW or 50%. This approach assumes that the operator is precisely aware of the time periods in which the battery system will be required to provide reliable capacity and is always able to charge the system in advance of the need. While it is likely that the operator will be able to anticipate the high load conditions that drive the system’s capacity need to a large extent, events driven by forced outages or low wind levels are less predictable and may result in a lower capacity contribution than is determined by this methodology.

PGE’s second approach attempts to capture in part the reliability impact of imperfect information. In the ELCC-based methodology, the assumption is that peak load conditions can be predicted on a day-ahead basis, but the exact timing of the event is uncertain. In this framework, the battery system follows a fixed monthly charging/discharging schedule on capacity-constrained days. PGE made use of the loss of load expectation (LOLE) calculated by month-hour in Chapter 5, Resource Adequacy, to establish this hourly schedule by month in which the battery discharges at its maximum four-hour capability for the four consecutive hours in each day with the largest probability of loss of load. The fixed schedule also incorporates adequate charging over the consecutive hours of the day with the lowest probability of loss of load to sustain the peak discharge level. Storage resources with durations exceeding four hours are scheduled to dispatch at their maximum capability over the longest period that can be sustained given charging requirements within the day. Given these schedules, PGE used the RECAP model to calculate the ELCC of a 50MW storage resource over a range of durations. Figure 8-5 shows the RECAP results juxtaposed against the results of the duration-based methodology.

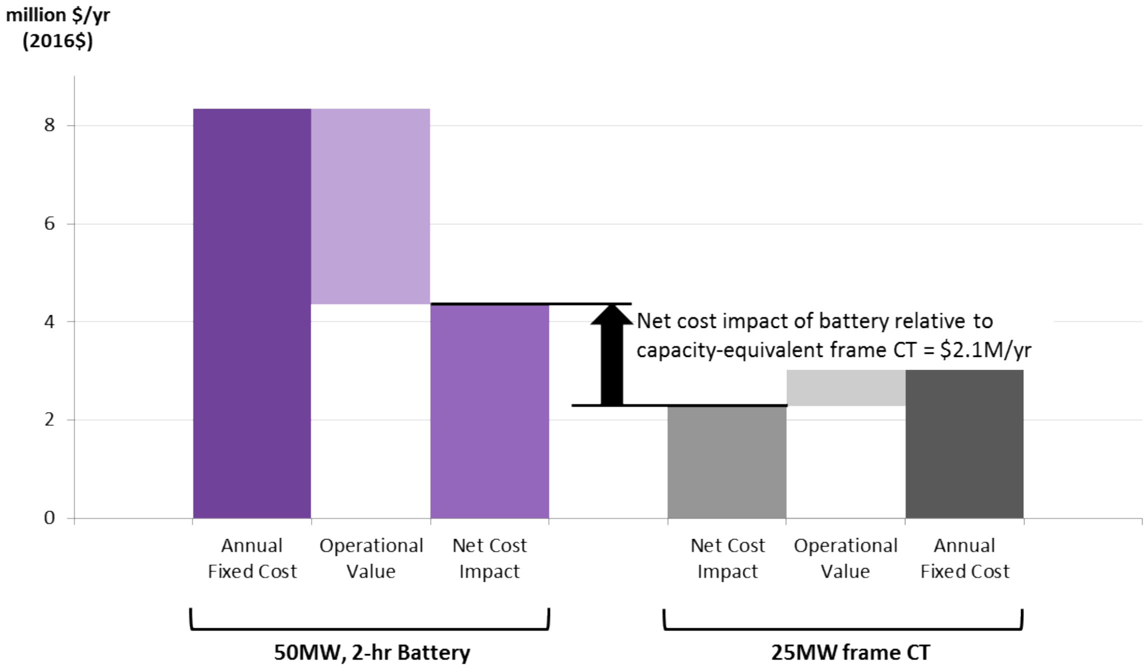
FIGURE 8-5: Capacity contribution of storage resources



PGE will continue to research the capacity contribution of energy storage resources and looks forward to learning from experiences in other jurisdictions as well as continued engagement with stakeholders in this effort.

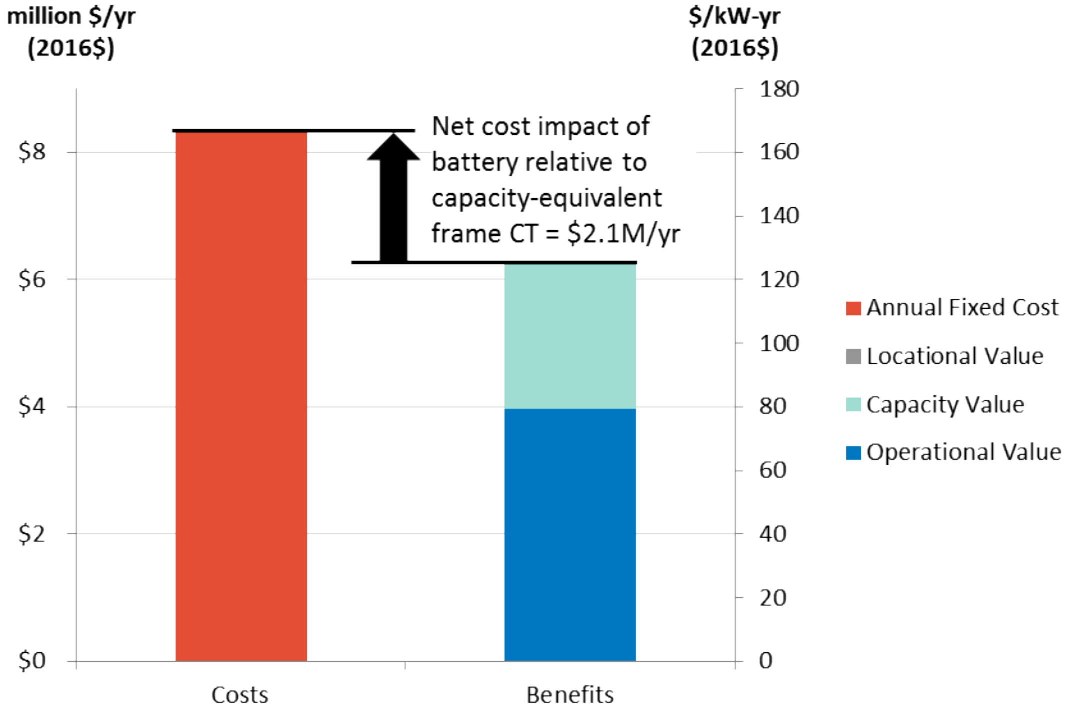
In the IRP portfolio evaluation framework, the capacity contribution of the battery system has the effect of reducing the incremental generic capacity resources needed in each year in which the battery is operational. As described in Chapter 10, Modeling Methodology, PGE models generic capacity resources from a cost and performance perspective as frame CTs (GE 7FA.05). The economic evaluation of battery systems in this portfolio context requires a comparison between the net cost impact of the battery system and the net cost impact of a frame CT sized to match the battery system's capacity contribution. For example, if the duration-based capacity contribution methodology described above is used, then a 50 MW 2-hr battery system is cost effective within a given portfolio if its annual cost net of its annual operational value is lower than the annual cost net of the annual operational value of a 25 MW frame CT. Figure 8-6 illustrates this economic comparison for an example 50 MW 2-hr battery in a 2021 Test Case.

FIGURE 8-6: Battery vs. frame CT net cost in 2021 test case



An alternative conceptual framework for establishing the cost effectiveness of a battery system is to attribute a capacity value to the battery system as a stacked benefit. This capacity value is equal to the net cost that can be avoided by displacing a capacity-equivalent default capacity resource. In this framework, cost effectiveness is established when the sum of the operational value, capacity value, and any additional quantified value streams exceeds the annual cost of the battery system. The same economic comparison shown in Figure 8-6 can be interpreted in terms of stacked benefits, as shown in Figure 8-7.

FIGURE 8-7: Energy storage stacked benefits example



8.5.2 Test Case Analysis

To determine whether the projected costs and benefits of battery systems warrant incorporation into the primary portfolios under consideration in the IRP, PGE applied the methodology described above to a 2021 Test Case. The 2021 Test Case employed the same assumptions described in Chapter 7, Supply Options, for the calculation of the Variable Energy Resource integration cost with incremental wind and solar additions (see Run 4).[188] The Company investigated two battery fleet sizes: a 50 MW deployment and a 100 MW deployment, each with 2-hr, 4-hr, or 6-hr duration, resulting in six total battery configurations.

8.5.2.1 Dispatch Behavior

The following figures illustrate the dispatch behavior of the 50 MW 4-hr battery system over the course of a June week (Figure 8-8) and a January week (Figure 8-9) in the 2021 Test Case.

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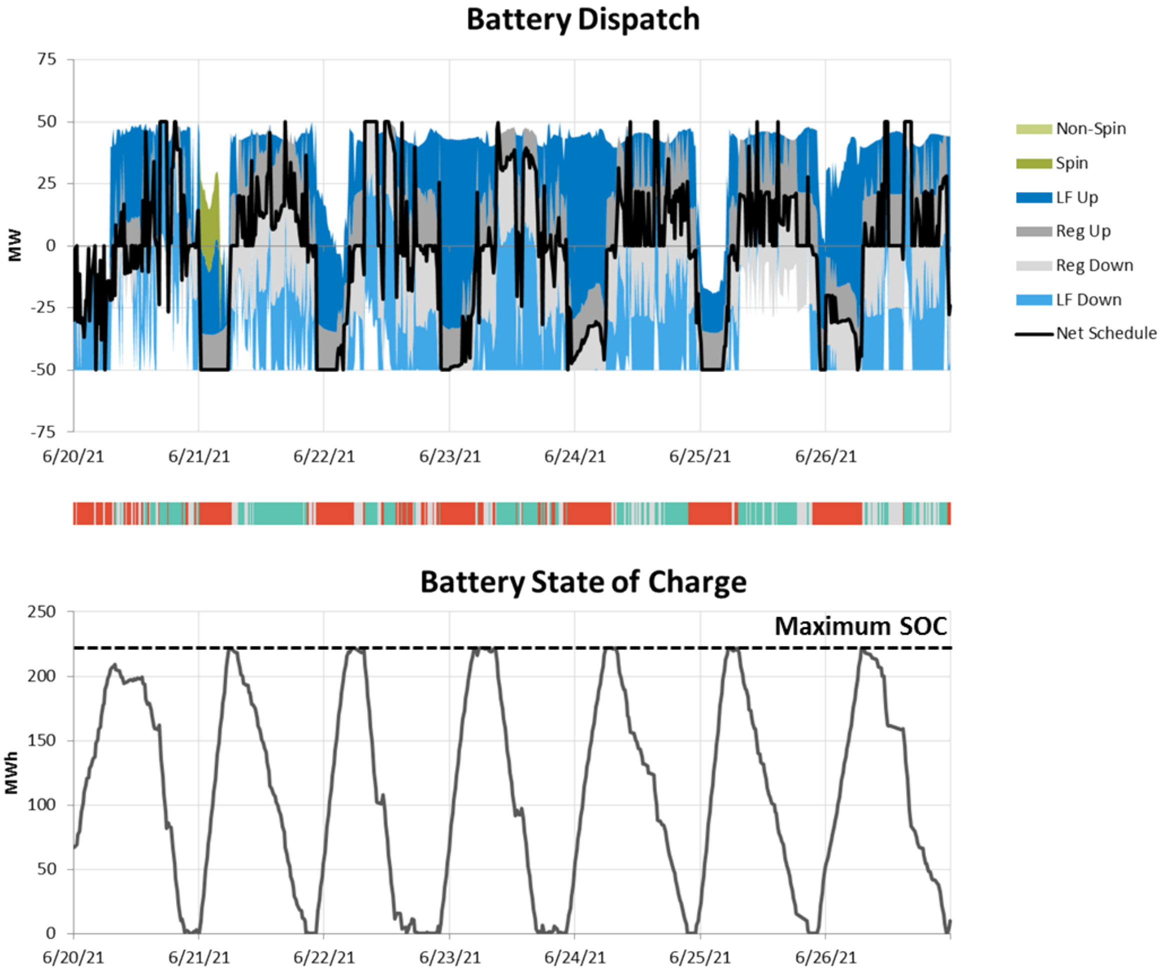
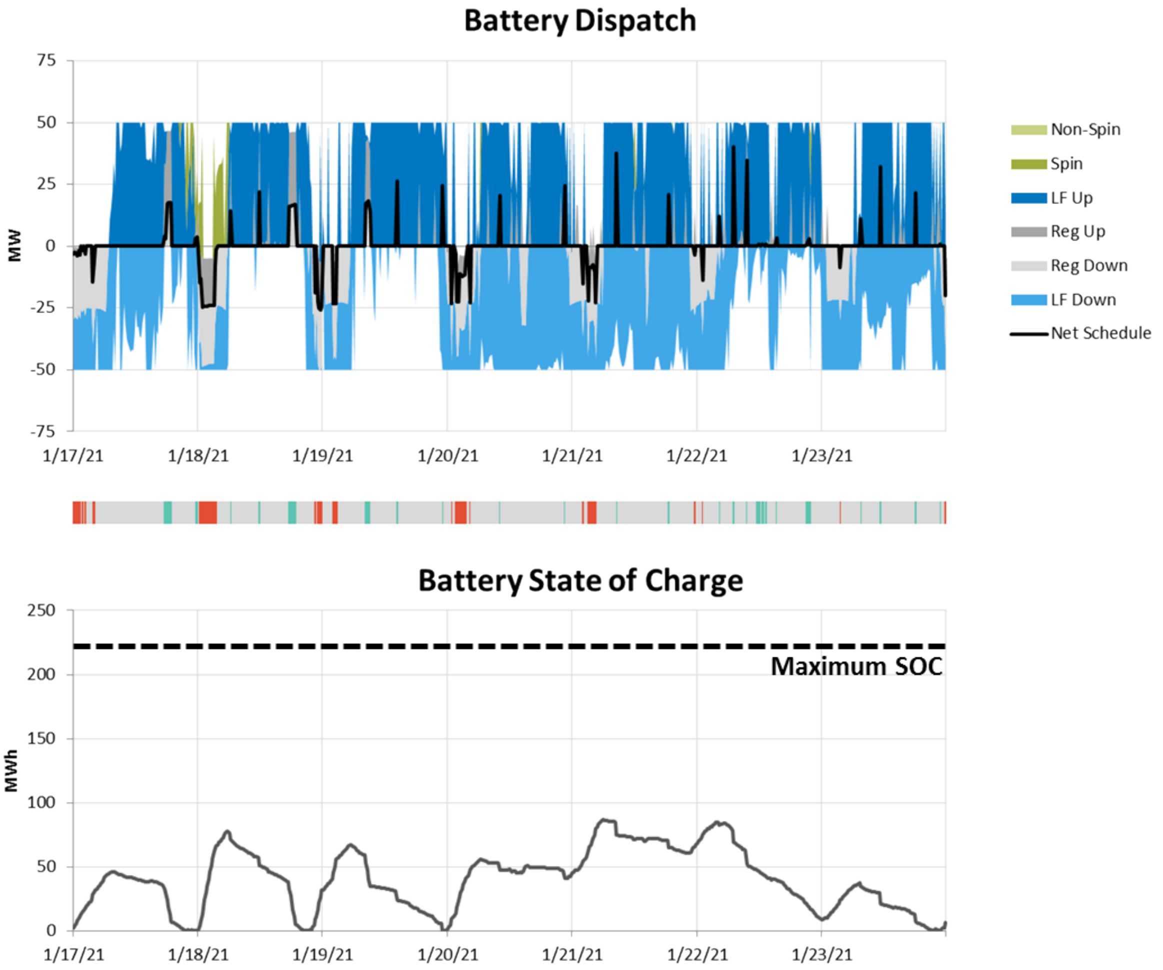
[188] The battery simulations presented here utilize two of the three ROM stages (day-ahead and 15-minute-ahead).

FIGURE 8-8: Simulated battery (50 MW/4-hr) dispatch across June 2021 week



In the June week, the battery tends to charge in the low load morning hours and discharge over the on-peak period of each day. As a result, the SOC has a fairly predictable daily pattern and the battery system can be seen making full use of the battery storage, hitting the maximum SOC on most days. At shorter timescales, the battery ramps up and down frequently to accommodate the flexibility needs of the system and provides reserve services in most time steps. In particular, the battery system uses its available capacity (charging and discharging) to provide upward and downward load following reserves (blue shaded areas) and regulation reserves (grey shaded areas), in addition to a small amount of spinning reserves (green shaded areas). During time steps in which the full battery capability (from maximum charging to maximum discharging) is not allocated to providing reserve services, two factors may be influencing the dispatch. First, there are some periods when other units on the system may be able to meet the reserve requirements at zero or very low cost (hydro systems in particular) – in these time steps, the battery does not provide a lower cost source for those reserves and is not scheduled to provide them. Second, the SOC of the battery limits, in part, the ability of the battery system to provide reserves. There may be periods at very high or very low SOC in which the battery does not make full use of its charging or discharging capacity to provide reserves due to these energy-related constraints.

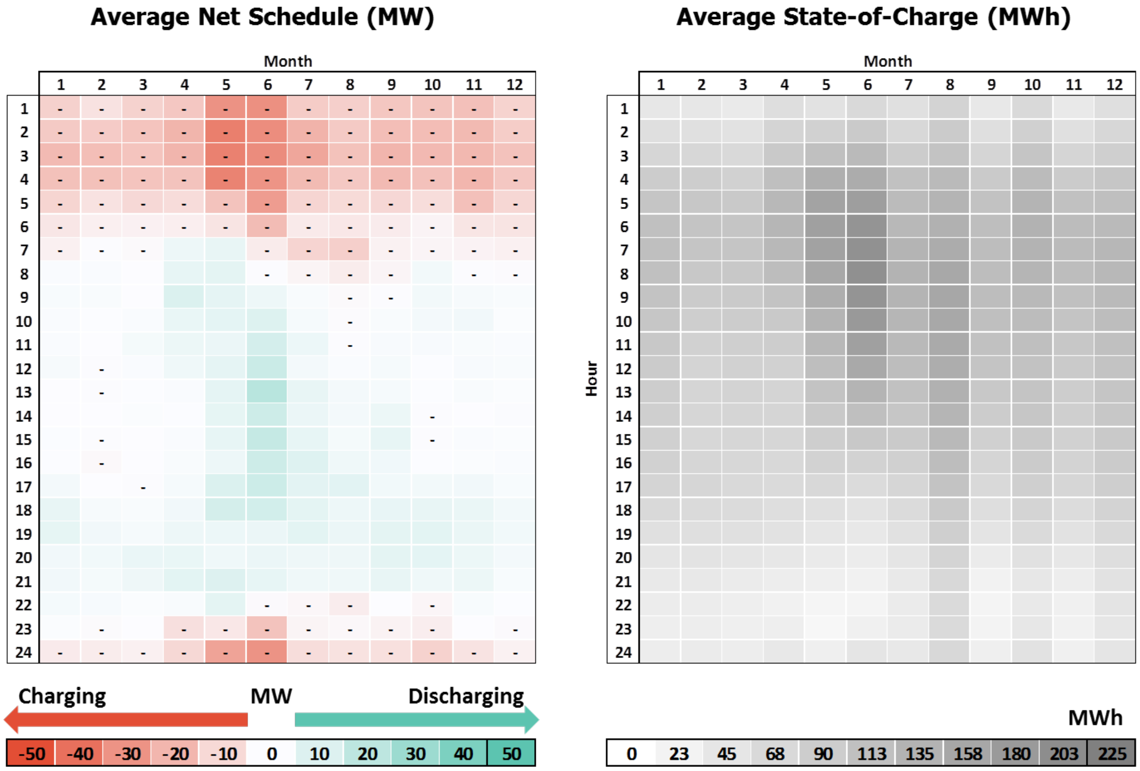
FIGURE 8-9: Simulated battery dispatch across January 2021 week



In contrast to the June week in which the battery provides both energy shifting and ancillary services, in the January week shown, most of the battery's capabilities are providing ancillary services. This results in a relatively high percentage of time steps in which the battery is scheduled at zero dispatch (not charging or discharging) in order to maximize the ability to provide reserves. As a result, the SOC remains well below the maximum storage capacity of the battery over the course of the week.

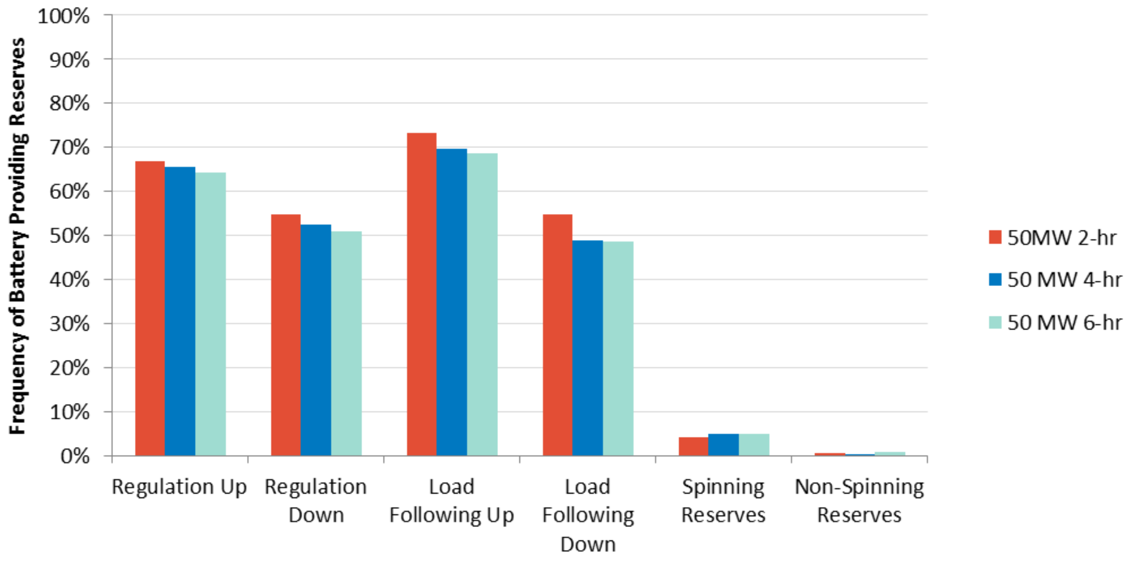
Across the year, the storage device tends to follow the diurnal trend shown in Figure 8-8, in which the device charges during off-peak periods and discharges during on-peak periods. The heat maps in Figure 8-10 show this trend, which is strongest in May and June.

FIGURE 8-10: Seasonal and diurnal battery dispatch patterns in 2021



The system also provides ancillary services throughout the year. Figure 8-11 shows frequency with which the 50 MW battery systems satisfy some portion of each reserve requirement across the 2021 test year. The battery systems provided regulation and/or load following reserves in a majority of time steps, but rarely provided spinning or non-spinning reserves, suggesting that regulation and load following may be higher value use cases for battery systems on the PGE system. Battery systems with shorter durations tended to provide reserve services slightly more often than longer duration systems. This observation is consistent with the capabilities of the systems—longer duration systems sometimes held less capacity for reserves in order to provide other services to the grid (e.g., energy shifting or arbitrage) when they were higher value. The battery systems also tended to provide upward reserves at a higher frequency than downward reserves due to the higher cost of meeting upward reserve requirements relative to downward reserve requirements with thermal units. Across all systems that were tested, the frequencies of providing the reserve services are sufficiently high to indicate that the battery systems are frequently providing multiple reserve services at the same time, as is demonstrated in Figure 8-8 and Figure 8-9 for the 50 MW 4-hr battery system.

FIGURE 8-11: Frequency of 50 MW battery systems providing reserve services in 2021



8.5.2.2 Identified Operational Value

The total operational value (including energy shifting, arbitrage, and ancillary services) identified in the 2021 Test Case is listed for six battery systems in Table 8-1. The normalized operational value indicates that the operational value of battery systems decreases on a per kW basis as battery deployments grow on the system given the same conditions. For example, a 50 MW 2-hr battery was able to provide $79.5/kW-yr of value to the system in 2021, while a 100 MW 2-hr battery provided only $64.4/kW-yr. The findings also suggest declining marginal operational value as the duration of the battery system increases, as longer duration batteries seem to provide little incremental value beyond the shorter duration batteries in the 2021 Test Case. Importantly, this snapshot year does not achieve the renewable levels required beyond 2021 to comply with SB 1547. PGE anticipates that these higher renewable levels as well as natural gas prices, CO_2 prices, PGE's participation in the Western EIM, and continued evolution of Western markets will shift the operational value of batteries over the course of their financial lifetimes.

TABLE 8-1: Simulated 2021 operational value

Battery system or fleet size	Operational Value (2016$/yr, million)	Operational Value (2016$/kW-yr)
50 MW, 2-hr	3.98	79.5
50 MW, 4-hr	4.21	84.2
50 MW, 6-hr	4.22	84.4
100 MW, 2-hr	6.44	64.4
100 MW, 4-hr	6.76	67.6
100 MW, 6-hr	6.76	67.6

8.5.2.3 Identified Capacity Value

Table 8-2 lists the capacity contributions of the six energy storage resources studied in this analysis. The lower bound corresponds to the ELCC-based methodology described above and the upper-bound corresponds to the duration-based methodology. PGE calculated the value attributed to the capacity contribution as the annual cost of a frame CT net of its operational value in 2021, as determined by ROM in the same 2021 Test Case. This yielded a net cost of capacity equal to $91.6/kW-yr. Note that the true levelized net cost of a frame CT would incorporate the operational value in each year over the full lifetime of the asset. However, for consistency with the single-year approach used to evaluate the battery systems, the net cost of capacity calculation assumes that the 2021 operational value of the frame CT is experienced across the full financial lifetime of the resource as a fixed quantity on a real basis.

TABLE 8-2: Battery system capacity value ranges

Battery system or fleet size	Capacity Contribution (MW)	Capacity Value (2016$/yr, million)	Capacity Value (2016$/kW-yr)
50 MW, 2-hr	17 - 25	1.52 - 2.29	30.4 - 45.8
50 MW, 4-hr	33 - 50	3.01 - 4.58	60.1 - 91.6
50 MW, 6-hr	40 - 50	3.67 - 4.58	73.3 - 91.6
100 MW, 2-hr	33 - 50	3.04 - 4.58	30.4 - 45.8
100 MW, 4-hr	66 - 100	6.01 - 9.16	60.1 - 91.6
100 MW, 6-hr	80 - 100	7.33 - 9.16	73.3 - 91.6

8.5.2.4 Economic Analysis

Table 8-3 summarizes the economic analysis for the 2-hr and 4-hr duration systems. Cost data was not available for a 6-hr battery system.

TABLE 8-3: Summary of battery system economic analysis

Configuration	50 MW, 2-hr	50 MW, 4-hr	100 MW, 2-hr	100 MW, 4-hr
Fixed Costs (2016$/kW-yr)	$167	$371	$167	$371
Operational Value (2016$/kW-yr)	(79.5)	(84.2)	(64.4)	(67.6)
Capacity Value (2016$/kW-yr)	(30.4) – (45.8)	(60.1) – (91.6)	(30.4) – (45.8)	(60.1) – (91.6)
Locational Value (2016$/kW-yr)	(0)	(0)	(0)	(0)
Net Cost Impact (2016$/kW-yr)	41.4 – 56.8	195 - 227	56.5 - 71.9	212 - 243

As shown in Table 8-3, all of the tested storage resources yielded a positive net cost impact relative to a frame CT, indicating that they do not represent a compelling cost effective resource option for inclusion in the full IRP portfolio analysis across each of the futures at this time. However, the Company recognizes that as technology costs continue to decline, the economics of battery storage on the PGE system may rapidly evolve, necessitating a more comprehensive analysis in the near future. With this in mind, PGE has identified the following next steps:

- Engage the ROM Technical Review Committee to refine the energy storage modeling methodology
- Continue to research the capacity contribution of energy storage resources
- Expand energy storage modeling to incorporate pumped storage systems
- Continue to explore options for full incorporation of energy storage evaluation into the IRP portfolio analysis

In particular, the energy storage evaluation exercise has highlighted the challenge of accurately quantifying the value of highly flexible resources in a planning exercise that spans several years and considers multiple futures. While it may be computationally infeasible to perform the operational analysis described above over the same set of portfolios, years, and futures evaluated in the IRP, it will become increasingly important to incorporate the insights from this type of operational modeling into the portfolio analysis framework. PGE will continue to engage stakeholders and to learn from planning exercises in other highly renewable jurisdictions as it works to incorporate flexibility and renewable integration considerations into the IRP process.

CHAPTER 9. Transmission Options

In evaluating PGE's various resource options to meet future obligations, PGE must assess the transmission service needed to deliver power from these resources to its customers.[189] A portion of PGE's existing (and potentially future) generating resources and market purchases lie outside the Company's service territory, including Tucannon River Wind Farm in eastern Washington, and the Carty Generating Station in central Oregon at the Boardman site. As such, PGE depends heavily on the Bonneville Power Administration (BPA)—and to a lesser extent PacifiCorp—to provide transmission service from PGE's supply-side resources and market purchases to serve the Company's customers. These resources include:

- Hydroelectric resources in central Washington, central Oregon, and east of Portland.
- Renewable resources east of the Cascades.
- Thermal resources in eastern Oregon and Montana.
- Thermal generation between Portland and the Puget Sound area.
- Market resources located in Western Energy Imbalance Market (EIM) Entities' footprints including the California Independent System Operator (CAISO). (See Figure 9-3.)

PGE anticipates that any additional renewable resources needed to meet the increased RPS requirements of SB 1547 will require transmission from the BPA system and/or PGE-owned transmission. Further, with PGE's participation in the Western EIM starting in the fourth quarter of 2017, the Company will need transmission service to provide imbalance service from PGE's Western EIM trading partners.[190] This chapter discusses the way in which PGE manages its portfolio of transmission assets.[191]

Chapter 9 also examines PGE's current transmission portfolio and expected future requirements. This assessment includes implications of transmission constraints on system reliability, PGE's ability to meet the enhanced RPS and PGE customers' ongoing power needs. Finally, the chapter addresses PGE's continued efforts to participate in regional transmission planning forums with other utilities and stakeholders.

Chapter Highlights

- ★ **PGE is heavily reliant on BPA transmission to deliver power to PGE customers.**
- ★ **Resources to meet RPS and reliability requirements may need new transmission in order to deliver the power to PGE customers.**
- ★ **Long-term transmission studies are needed to examine the impacts of increased levels of renewables.**

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[189] Bulk Electric System transmission, both owned by PGE and owned by other regional entities, provides locational diversity potential and flexibility in siting considerations.

[190] Balancing load service may be provided from other EIM participating resources, based on a security constrained economic dispatch algorithm. However, PGE must enter each hour planning to meet all of its energy and capacity needs as if no Western EIM exists.

[191] It is important to note that PGE maintains functional separation between its Market and Transmission functions. This separation of functions requires delineation between transmission assets and activities performed by the two entities. In this section, PGE Market function generally refers to the entity responsible for purchasing and managing transmission rights, while PGE Transmission function refers to the entity responsible for planning, construction, operation and reliability of the PGE-owned transmission system.

9.1 Transmission Resources and Assessment

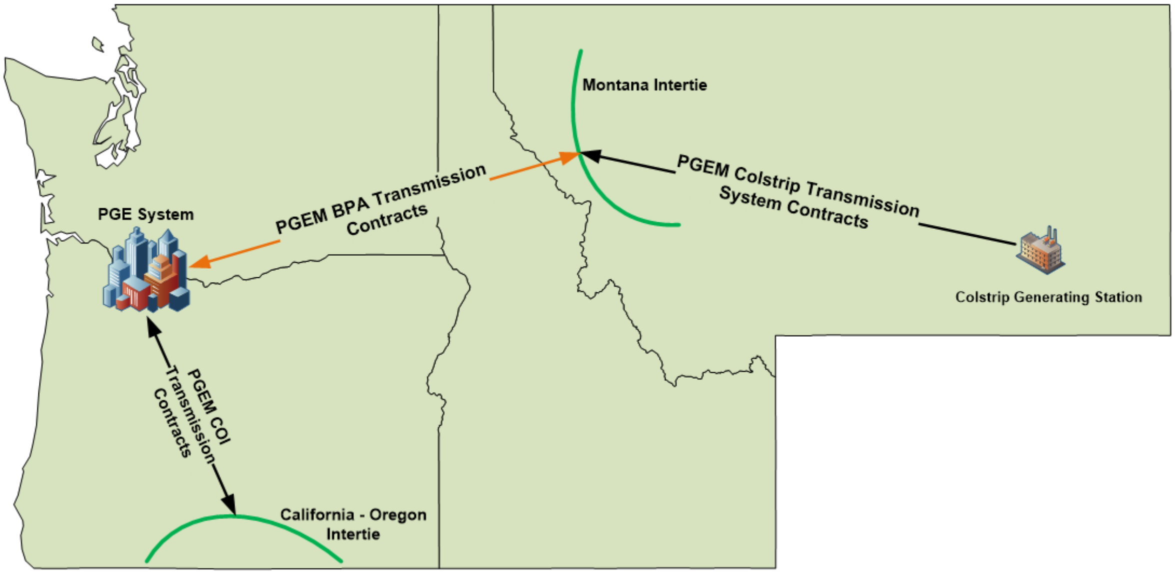
9.1.1 PGE Transmission Resources and Delivery Arrangements/Portfolio

The PGE service territory is a compact area located primarily in the Willamette Valley and occupies a small area of the Pacific Northwest. Most of PGE's existing transmission assets are within the Company's service territory.

BPA owns the majority of the transmission interconnected with the PGE system and 75 percent of the transmission in the Pacific Northwest.[192] The Balancing Areas of PGE, BPA, and PacifiCorp are physically adjacent, making it possible for PGE, BPA, and PacifiCorp to engage in system-to-system energy transfers.

PGE Transmission also owns a portion of the AC Intertie, a valuable transmission path between the Pacific Northwest and California. PGE Transmission owns a portion of the Colstrip Transmission System capacity, providing the Company transmission service from Colstrip generation westward into the BPA system. PGE's Market Function (PGEM) reserves transmission for capacity rights on both the AC Intertie and the Montana Intertie, enabling energy pathways into the Pacific Northwest as shown in Figure 9-1.

FIGURE 9-1: Providers of PGE market function Intertie transmission contracts



PGEM utilizes point-to-point (PTP) transmission contracts to deliver thermal, hydro, and wind resources, and market purchases and sales to balance load. PGEM presently reserves 3670 MW of transmission capacity from BPA Transmission under PTP contracts. PGE owns and operates 4205 MW of transmission capacity under various contracts. Port Westward area generation capacity (identified in Figure 9-2 as Trojan Facilities) exceeds PGEM's transmission rights on PGE-owned transmission, requiring a combination of rights on PGE-owned and BPA-owned transmission.

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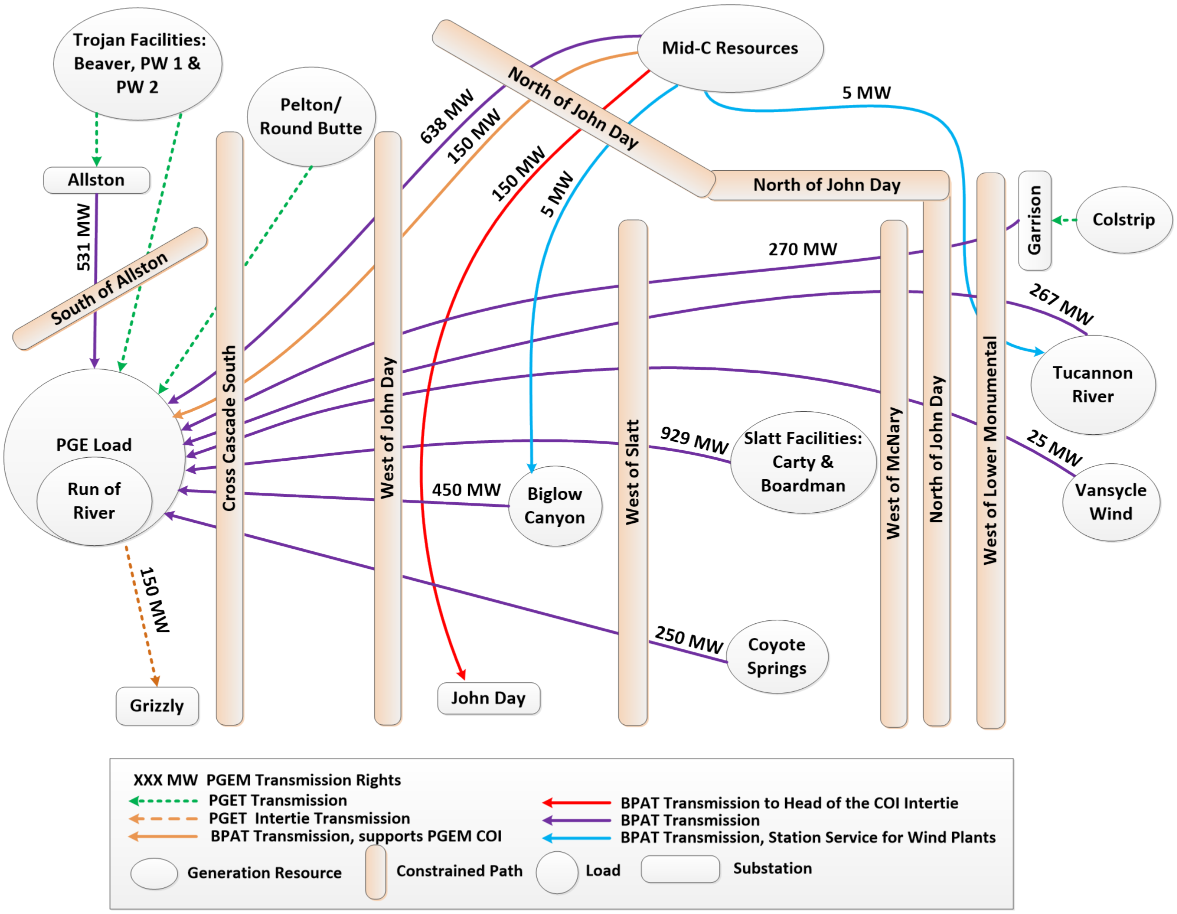
[192] About BPA Watch:Basics - Understanding the BPA. (n.d.). Retrieved October 28, 2016, from http://www.bpawatch.com/BPABasics.html.

BPA transmission contracts account for nearly all the power PGE obtains from its existing remote generating resources. The Company delivers power from its Pelton and Round Butte hydro facilities through a combination of PGE transmission and other contracted rights. Because PGE’s Westside Hydro plants (which reside on the Clackamas River) are inside the PGE service territory, no transmission service is necessary.

PGE's transmission rights on the AC Intertie and the Colstrip Transmission System provide the Company with critical access to power. From a supply perspective, the AC Intertie provides access to energy located in California for reliability purposes in times of limited Pacific Northwest market liquidity. The AC Intertie will be a vital access point for PGE’s Western EIM participation. Similarly, the Colstrip Transmission System is an important transmission path for PGE to deliver reliable power from Colstrip to PGE customers.

PGE’s transmission rights and generation are generally balanced, except for the Company's transmission rights from Mid-Columbia (Mid-C), which are in excess of PGE's generation from Mid-C. This allows the Company to access the market for balancing load and meeting peak demand from the regional hub. See Figure 9-2 for PGE's overall transmission holdings and use for generating resources in a portion of the Northwest transmission system.

FIGURE 9-2: PGE's market function transmission resources and use with new resources and transmission



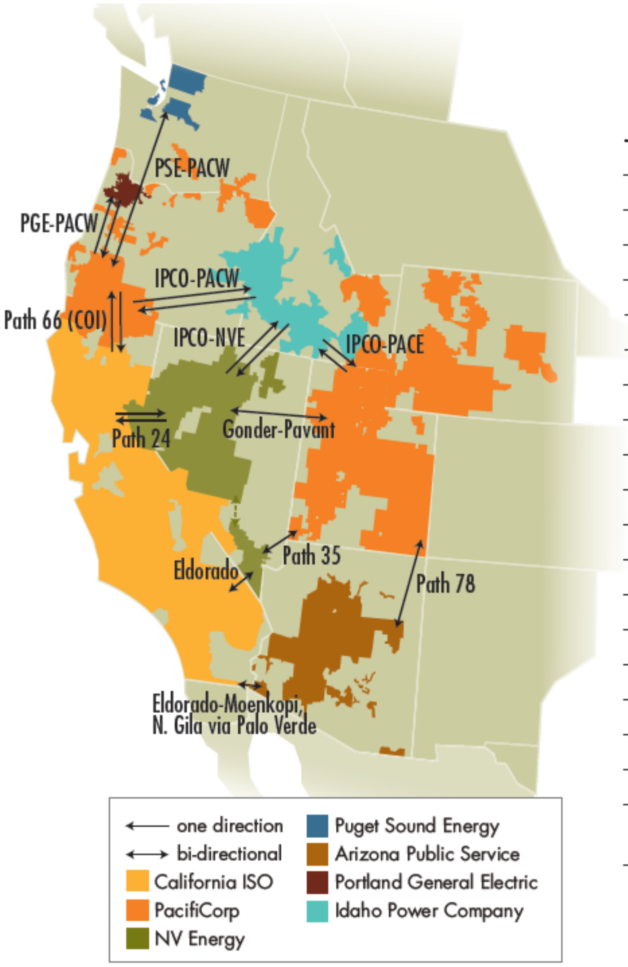
The tan bars (constrained paths) limit the overall capacity available in certain areas. The values represent PGE's transmission position relative to generation for each location.

9.1.2 PGE Resource and Energy Market Transmission Needs

To enable the delivery of energy from existing and future resources, and to provide imbalance service through the Western EIM, PGE will rely upon its existing transmission rights to meet native load. As shown Figure 9-2, PGE's contracted transmission from BPA Transmission is 3670 MW. PGE procures sufficient transmission capacity to support the firm capacity of the resources that it integrates. To ensure that it can deliver the full output of PGE-owned variable energy resources, PGEM's contracts for firm transmission rights must match the nameplate rating of the generation.

PGE will also use its transmission assets to access Western EIM entities and the California Independent System Operator (CAISO). Direct access to a liquid EIM enhances PGE's ability to efficiently integrate variable resources on an intra-hour energy basis. However, access to the EIM relies on resource adequacy requirements that PGE cannot obtain through that market. PGE intends to use transmission contracts and reservations to participate in the Western EIM. Figure 9-3 shows the capacity ratings of the transmission paths in the Western EIM.

FIGURE 9-3: Western EIM Transmission Paths



Path	Estimated Max Capacity (MW)*
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	1,500
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
PSE to PACW	300
PGE to PACW	306
PACW to PGE	276
IPCO to PACW	1,587
PACW to IPCO	510
IPCO to NVE	478
NVE to IPCO	262
IPCO to PACE	1,000
PACE to IPCO	2,557
Eldorado, Moenkopi, N. Gila, Palo Verde	2,500
Path 78	600

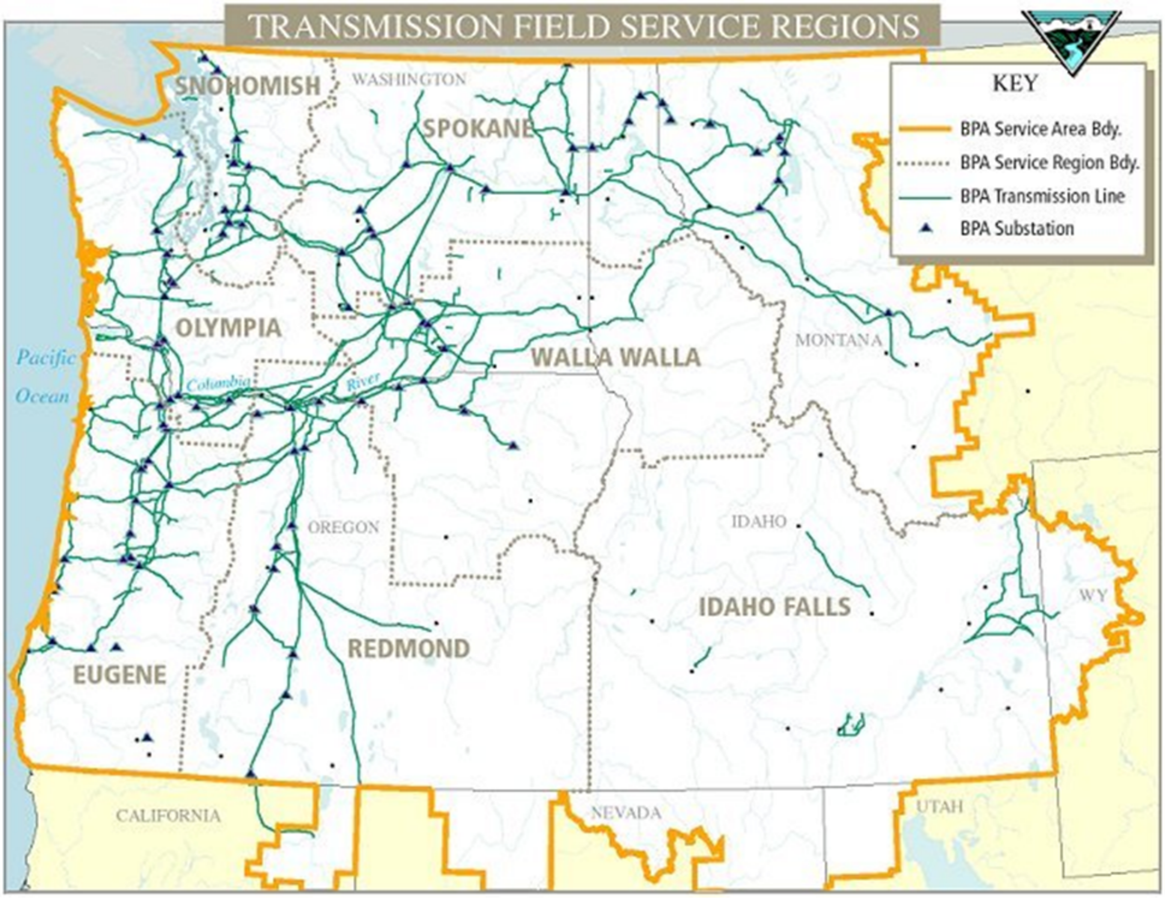
**Current as of May 2016*

Source: California ISO, March 2016

9.1.3 Regional Transmission Assessment

Since its creation in 1937, BPA has played a central role in managing the power and transmission facilities of the Federal Columbia River Power System in the Pacific Northwest. The BPA transmission system includes 15,000 miles of wires and 300 substations in eight states. BPA provides three-fourths of the Northwest's high-voltage transmission as it moves power from 31 federal hydroelectric stations and one nuclear power station to Northwest customers. BPA's large interregional transmission lines connect power systems from as far away as Canada and the Southwest U.S., and allow for the sale of surplus power outside the region and the movement of power within the region. Figure 9-4 shows the BPA Service Area Boundary.

FIGURE 9-4: BPA Service Area



BPA is experiencing increased stress on its transmission system due to:

- Changing load growth patterns;
- Emerging and diverse generation resources;
- Evolving market structures.

In response, BPA continues to evaluate its system management techniques and transmission product offerings. Usage of the transmission system consumes available transfer capability across cutplanes (i.e., constrained paths). BPA will limit or curtail the usage of the system to stay within the transfer limits of the cutplanes as a way to maintain transmission system reliability. BPA may also dispatch federal and nonfederal generation in its balancing authority area, based on merit order dispatch, as another method of staying within cutplane limits. This is counter to

A cutplane is an imaginary line that is used on a transmission map to identify which transmission lines make up a transmission path. Cutplanes are used to monitor power flows on key portions of the transmission system.

the Western EIM dispatch, which uses congestion pricing to maximize transfer capacity on regional transmission assets included in its Full Network Model in economic merit order.

BPA offers a variety of transmission products that allows users of the transmission system, and BPA as the transmission provider, to maximize system use. These product offerings recognize the fact that outside of peak seasons, much of the transfer capacity goes unused. The overall impact of squeezing out the remaining transmission capacity to defer expansion in the region's transmission system has been to produce complex constraint management systems and procedures in order to ensure reliability.

FIGURE 9-5: Pacific Northwest Transmission System with BPA Cutplanes

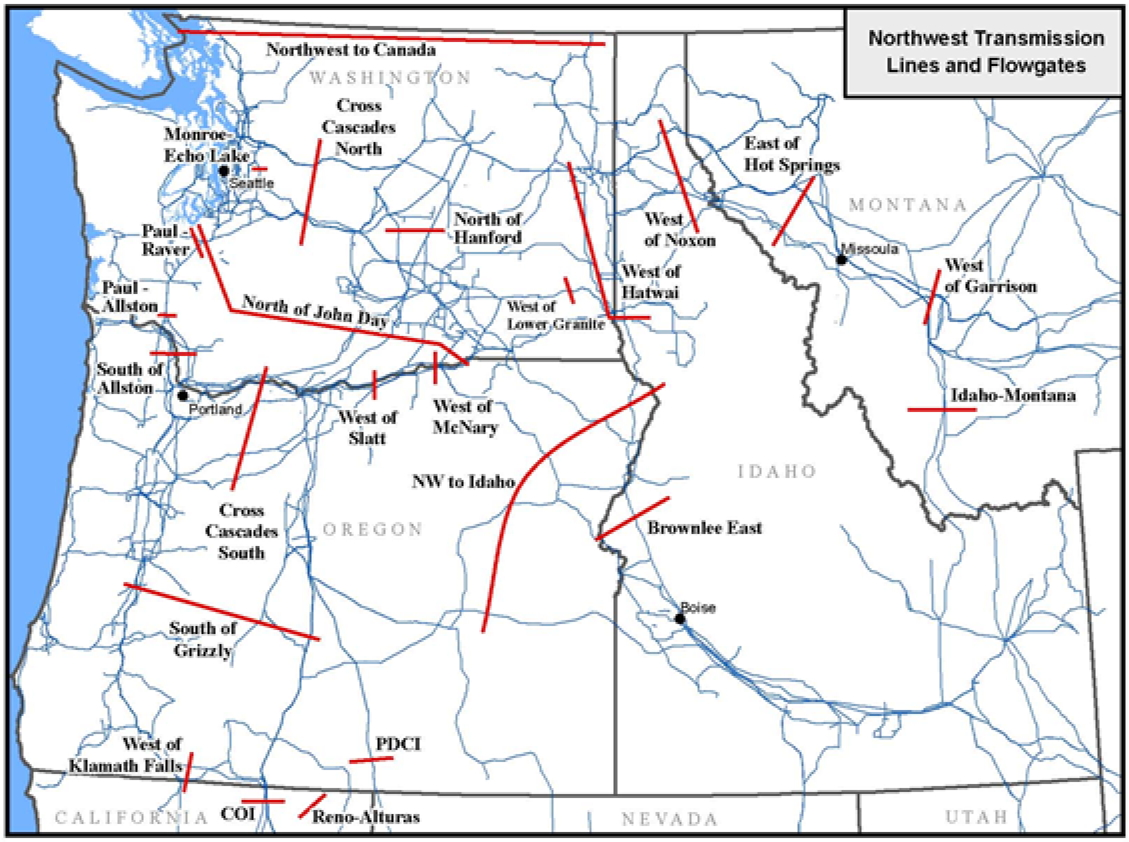


Figure 9-5 provides a graphical representation of the Pacific Northwest transmission system and the major cutplanes monitored by BPA. The blue lines drawn on the figure are the major transmission lines that serve the Pacific Northwest. The red lines show the major intra-regional cutplanes that BPA manages. These interties and path limits restrict both intra and interregional transfers. The South of Allston (SoA) cutplane, determined by BPA to have no available capacity, impacts PGE's Port Westward area generation located north of the cutplane. BPA has indicated the SoA cutplane is one of the most congested cutplanes on BPA's transmission network. Due to the flow-based nature of the interconnected power grid, this constraint creates real-time limits on flows to the Portland load centers, irrespective of where the source generation resides in BPA's system.

BPA has initiated real-time reductions on the South of Allston cutplane, resulting in activation of the Remedial Action Scheme (RAS) used for outages on the Allston-Keeler and Keeler-Pearl 500 kV lines. BPA periodically curtails flows on the SoA path to reduce the amount of generation forced off-line during a RAS event and to allow greater flexibility in meeting the N-1 outage recovery requirements[193]. Without curtailing these flows, an N-1 outage may require significant generation curtailments.

The highest stresses on BPA's bulk transmission system occur during the summer and winter peak load periods. During the summer, when high regional generation serves area loads west of the Cascades and transfers power to California and the Desert Southwest, the SoA cutplane becomes flow limited. This flow limitation can at times negatively impact PGE's Port Westward generation flexibility during peak load hours.

BPA recently completed several system upgrades, including West of McNary, Big Eddy/Knight, and Central Ferry/Lower Monumental. The I-5 Reinforcement project, which would provide specific relief for PGE resources and the SoA cutplane, continues to experience schedule delays. BPA has initiated efforts to defer this upgrade using non-wires solutions. Non-wires solutions seek generation or load redispatch in order to provide the necessary transmission relief. This redispatch may result in limiting dispatch flexibility on identified units, such as the PGE units located at Port Westward.

With the implementation of a 50 percent renewable portfolio standard in California (by 2030) and Oregon (by 2040), energy flows on the regional transmission system may change dramatically. The location, timing, and amount of excess new renewable capacity may serve as the bases for this change in energy flows.

Since the locations for new resources are unknown at this time, smaller, targeted sub-regional reinforcements are more likely to occur as generator owners evaluate their ability to provide the flexible capacity and energy products needed to integrate renewables at the 50 percent RPS level. To balance these additional variable resources, PGE may target sub-regional transmission reinforcements to enable access to the most highly-flexible generation situated nearest to load.

9.2 Regional Transmission Planning

Clearly there is a need for coordinated transmission planning to address the region's transmission challenges. Congress and FERC also recognize the need to improve regional transmission planning. As a result, transmission planning has undergone significant transformation over the past 25 years, through a series of acts enacted by Congress and orders issued by FERC. Particularly, FERC Orders 890 and 1000 shaped the transmission planning process for the Western Bulk Electric System.

Transmission planning remains a complex function coordinated between affected utilities using various processes and procedures established by multiple organizations. These organizations have differing roles in transmission planning. PGE Transmission describes its Transmission Planning Process in Attachment K of its Open Access Transmission Tariff (OATT). The following section contains a brief description of PGE's participation in regional transmission organizations. These

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[193] The N-1 outage criterion provides that for multiple transmission lines delivering power to the same point, if one of the lines goes out of service, the remaining lines must be able to carry both the load they were carrying before the event, plus the load carried by the line that is out of service.

organizations provide a forum for collaborative regional transmission planning through open and transparent processes and stakeholder forums.

9.2.1 Regional Planning Entities and FERC Order 1000

9.2.1.1 Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) formed in 2006 to address the future sub-regional transmission and resource needs of its members and their customers. PGE became a member of NTTG in 2008. Other participating utilities include PacifiCorp, Idaho Power, NorthWestern Energy, Deseret Power Electric Cooperative, Utah Associated Municipal Power Systems, and MATL LLP.

As a Funding Member, PGE satisfies its regional transmission planning commitment and objectives through NTTG. NTTG focuses on evaluation of transmission projects that move power across the regional bulk transmission system, servicing loads that include parts of Utah, Wyoming, Montana, Idaho, Oregon, Washington, and California. NTTG also provides an open forum for coordinated analysis between interregional planning efforts with adjacent regional groups as a part of the Western Planning Regions with Columbia Grid, WestConnect, and CAISO.

FIGURE 9-6: NTTG members' transmission facilities

9.2.1.2 Columbia Grid

Columbia Grid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the sub-regional portion of the Northwest transmission grid owned and operated by its members. Members of Columbia Grid include BPA, Avista Corporation, Puget Sound Energy, Seattle City Light, Grant County PUD, and Snohomish County PUD. PGE Transmission coordinates with Columbia Grid on interregional planning through NTTG. PGE participates in Columbia Grid regional planning forums and open planning processes as a stakeholder.

9.3 BPA's Network Open Seasons

In 2008, BPA introduced its first Network Open Season (NOS) process to effectively manage its transmission service request queue and alleviate the bottleneck created by previous transmission planning and funding mechanisms. BPA conducted NOS processes in 2008, 2009, and 2010, which made it possible for BPA to process copious transmission service requests and offer thousands of MWs of new transmission service. BPA's NOS supported the growth and integration of large-scale wind generation projects.

Two key features of BPA's NOS aided the success of the process:

1. Allowing transmission service customers to commit—in advance—to reserve service at embedded-cost rates by signing a Precedent Transmission Service Agreement (PTSA);
2. Performing a single cluster study (rather than individual system impact studies) of all requests to determine what new transmission facilities, if any, are necessary to accommodate the numerous requests.

The PTSA alleviated the need for BPA's customers to fund—in advance—the entire cost of transmission network facilities needed to provide the service. BPA made the necessary investment through its borrowing authority or other arrangements. The clustering of transmission requests sped up the system impact analyses and allowed BPA to evaluate the network effects that result from interactions among requests, including implications on system reliability.

In 2011, BPA announced that, due to the fast pace of wind development and the hundreds of requests for service submitted through the NOS, it was delaying the start of the next NOS process.[194] BPA stated its intent to engage in regional dialogue regarding the challenges associated with its NOS and to put forth future revisions to the NOS process.

In 2016, BPA initiated a new business process to replace the traditional NOS process. BPA's Transmission Service Request Study and Expansion Process (TSEP) is a five-phased process, where BPA processes and studies transmission service requests collectively; however, customer's may request an individual study for a specific transmission service request (TSR). In addition to the traditional NOS processes, BPA's new process includes financial evaluation, capital prioritization evaluation, and the opportunity for alternative ownership structures. On June 30, 2016, BPA issued a notice alerting TSRs of its intent to conduct a Cluster Study.

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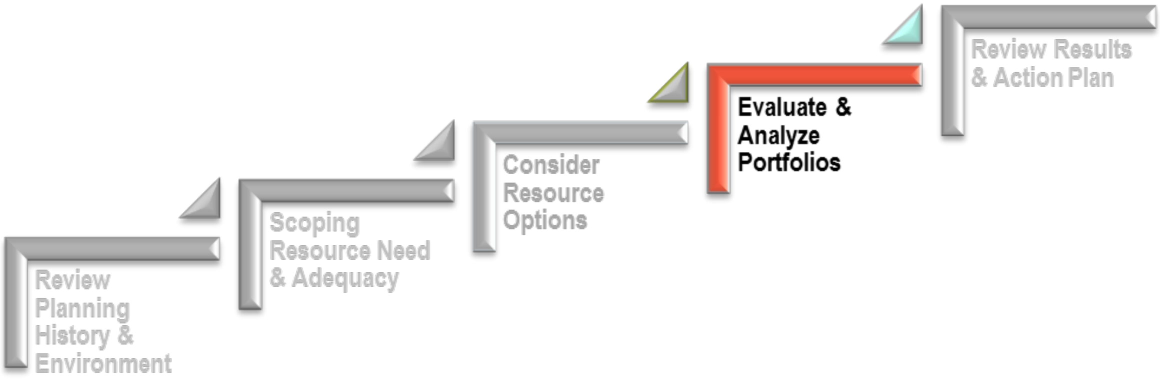
[194] Network Open Season Announcement, Bonneville Power Administration, April 21, 2011, retrieved on Aug. 9, 2016.

PGE will evaluate its participation in future BPA NOS processes to acquire transmission rights for future generation resources as needed.

9.4 Future Transmission

All portfolios in the IRP incorporate transmission costs, including those unique to each portfolio (with the exception of portfolios that include Montana Wind). For modeling purposes, PGE assigns BPA tariff rates to future generation projects in the Company's portfolio that require BPA transmission. In addition, the portfolio analysis includes an analysis of wind resources in Montana. To model the effect of the limited east-to-west transfer capability on the existing transmission facilities, the Company does not estimate a specific transmission cost. Rather, PGE uses the analysis of the capacity and energy cost benefits of Montana Wind relative to Pacific Northwest Wind (PNW Wind) to provide the maximum incremental cost of transmission for Montana Wind in order to be competitive to PNW Wind. The results of this analysis are provided in Section 12.3, General Portfolio Conclusions and Consideration for Action Plan. The possibility of obtaining transmission under that price threshold will be determined in the competitive bidding process.

Part IV. Methodology and Scoring



CHAPTER 10. Modeling Methodology

The goal of the IRP is to identify a mix of new and existing resources that provides the best combination of expected costs, and associated risks and uncertainties for PGE and its customers. This chapter provides an overview of the data, analytical methods, and tools PGE uses to assess resource portfolio performance in this IRP.

Chapter Highlights

- ★ **Fundamental analyses of electricity supply and demand in the Western Electricity Coordinating Council (WECC) are performed; dispatching existing and potential new resources under various conditions, and resulting in projected hourly wholesale market prices.**
- ★ **Futures test various risk factors related to CO_2 prices, natural gas prices, load growth, and resource parameters.**
- ★ **Discrete candidate resource portfolios are designed to understand the potential costs and benefits of specific resources decisions.**
- ★ **Various factors affecting the Renewable Resource Portfolio (RPS) compliance strategy are considered.**

10.1 Modeling Introduction

In general, long-term planning is subject to much uncertainty. Utility resource planning is no different; the IRP analytical process must consider the inherent uncertainties associated with customer demand forecasts, resource cost and technological parameters, the balance of regional electricity supply and demand, fuel cost and availability, as well as state and federal energy and environmental policies. PGE relies on scenario analysis to incorporate aspects of these uncertainties into its long-term plan. The Company believes it is most effective to assess resource and portfolio performance across a diverse range of credible potential future environments. While no singular solution exists when evaluating an uncertain energy supply future, the insights derived from various quantitative performance measures guide PGE's decision-making with respect to the selection of a preferred resource portfolio and development of an action plan.

PGE uses the following terminology throughout its discussion of the IRP modeling approach:

- **Future.** A set of deterministic input variables that describe a variety of potential circumstances which drive the economic performance of resources over the planning horizon. PGE assesses multiple futures in order to test the performance of candidate portfolios.
- **Portfolio.** A mix of resources which will meet PGE's future Renwable Portfolio Standards (RPS) and capacity needs.
- **Reference Case.** A future selected to represent the inputs for PGE's IRP model corresponding to an expected base case set of assumptions.
- **Scenario.** The intersection of a portfolio with a future; Table 10-1 visually demonstrates this relationship.

TABLE 10-1: Portfolios, futures, and scenarios

Portfolio	Future			
	Future 1	Future 2	Future 3	Future 4
Portfolio 1	Scenario 1,1	Scenario 1,2	Scenario 1,3	Scenario 1,4
Portfolio 2	Scenario 2,1	Scenario 2,2	Scenario 2,3	Scenario 2,4
Portfolio 3	Scenario 3,1	Scenario 3,2	Scenario 3,3	Scenario 3,4
Portfolio 4	Scenario 4,1	Scenario 4,2	Scenario 4,3	Scenario 4,4

Later in this chapter, PGE provides detailed discussions of the portfolios and futures assessed in this IRP, including the components of its Reference Case.

As with PGE's recent IRPs, a primary resource modeling tool is AURORAxmp® (AURORA). AURORA allows PGE to perform fundamental analysis of the western power markets under various assumptions and test the performance of candidate resource portfolios in those environments. PGE uses the net present value of revenue requirements (NPVRR) to summarize the expected cost of portfolios. The NPVRR includes the fixed and variable costs associated with owning and operating the respective resources, as well as the net market revenue or expense associated with net sales or purchases in the portfolio. PGE evaluates portfolio risk according to two primary categories:

1. **Reliability risk:** Serves as a threshold for portfolio design; and,
2. **Deterministic risk:** Referred to above as "futures."

Chapter 5, Resource Adequacy, provides further detail regarding PGE's assessment of Reliability risk. The remainder of this chapter primarily focuses on PGE's approaches to resource modeling as well as describing the futures that will be used for the cost and Deterministic risk assessment. Chapter 11, Scoring Metrics, and Chapter 12, Modeling Results, present the metrics used to assess cost and risk, as well as the results of applying those metrics.

10.2 Modeling Process Overview

PGE's resource and portfolio modeling process takes place in four primary steps:

1. PGE conducts a fundamental analysis of the WECC using AURORA, simulating hourly dispatch of all regional resources. This process includes:
    a. Collecting resource costs and operating parameters using third-party information in order to compute life-cycle revenue requirements for each new WECC/PGE resource option (see also Demand and Supply Options in Chapter 6, Demand Options, and Chapter 7, Supply Options, respectively). Additionally, PGE relies on data provided by Wood Mackenzie, an independent third-party expert in commodity markets fundamental analysis.
    b. Identifying a topology that captures the main transmission links within WECC.
    c. Consistent compilation of updated fuel costs, environmental costs, and constraints to reflect plausible future conditions.
    d. Developing regional capacity expansion plans that adhere to policy and regulatory constraints, economic costs, and planning reserve margins in order to best represent WECC resource developments under future conditions and impose resource adequacy by State or region.
2. Given these representations of the region, PGE tests the cost and risk of potential alternative long-term procurement strategies (portfolios) available to it. This, in turn, requires:
    a. Calculating the fixed revenue requirement (capital and fixed operating costs) for each resource using PGE's Excel-based revenue requirement model;
    b. Dispatching portfolios comprising PGE's existing and future resources in AURORA under various future conditions (Futures);
    c. Calculating the variable cost of each portfolio in AURORA across the analysis time period;
    d. Combining the variable and fixed costs for each of the alternative portfolios;
    e. Calculating the NPVRR over the planning horizon (from 2017 through 2050) for each portfolio under each future;

   f. Using scenario analysis to assess risk for each portfolio based on changes in portfolio costs under various futures;
   g. Measuring the carbon footprint of different resource strategies.

3. PGE tests the reliability of each portfolio by assessing the joint probability distributions of load, hydro, wind production, and plant availability. More specifically, PGE imposes a resource adequacy target of a maximum loss of load of 2.4 hours/year given the joint probabilities identified above. PGE imposes this resource adequacy target of 2.4 hours/year on all portfolios except for the *RPS Wind 2018 + No Capacity Action* portfolio, which is intentionally capacity inadequate in order to assess the relative cost of maintaining resource adequacy. The *RPS Wind 2018 + No Capacity Action* Portfolio adds no resources beyond those needed to achieve RPS compliance. For more detail regarding PGE's resource adequacy assessment, see Chapter 5, Resource Adequacy.

4. Finally, PGE compares portfolios using the scoring metrics discussed in Chapter 11, Scoring Metrics, to determine the portfolio providing the best combination of expected costs and associated risks and uncertainties for PGE and its customers. Chapter 12, Modeling Results, presents the results of this comparison.

10.2.1 Fundamental Analysis of WECC Electricity Market Prices

PGE uses AURORA to model the long-term supply, demand, and transmission relationships in the region. The Company applies fundamental parameters such as fuel prices, plant technologies, and carbon policy to these modeled relationships, resulting in power market prices for various points across the WECC.

AURORA simulates the WECC by representing the most significant demand hubs as a zones, each with its own power plants and transmission links for import and exports of electricity to other zones. PGE refers to such representation as WECC topology. AURORA simulates markets on an hourly scale by calculating the electricity demand of each zone and stacking resources to meet demand and reliability standards with the least-cost resources, given operating constraints. The variable cost of the most expensive generating plant or increment of load curtailment required to meet load for each hour of the forecast period establishes the marginal price for each zone.

Inputs to AURORA include load, resource parameters, transmission capability, fuel prices, hydro capacity and generation, and emission rates for each resource in the WECC across the analysis horizon. Additionally, PGE's modeling relies on the regional assumptions mainly developed by Wood Mackenzie. The Company updates these assumptions, where necessary, by using its professional judgment, the expertise of consultants, and various studies. The next section discusses the main assumptions used by PGE.

10.2.1.1 Regional Resource Modeling Structure

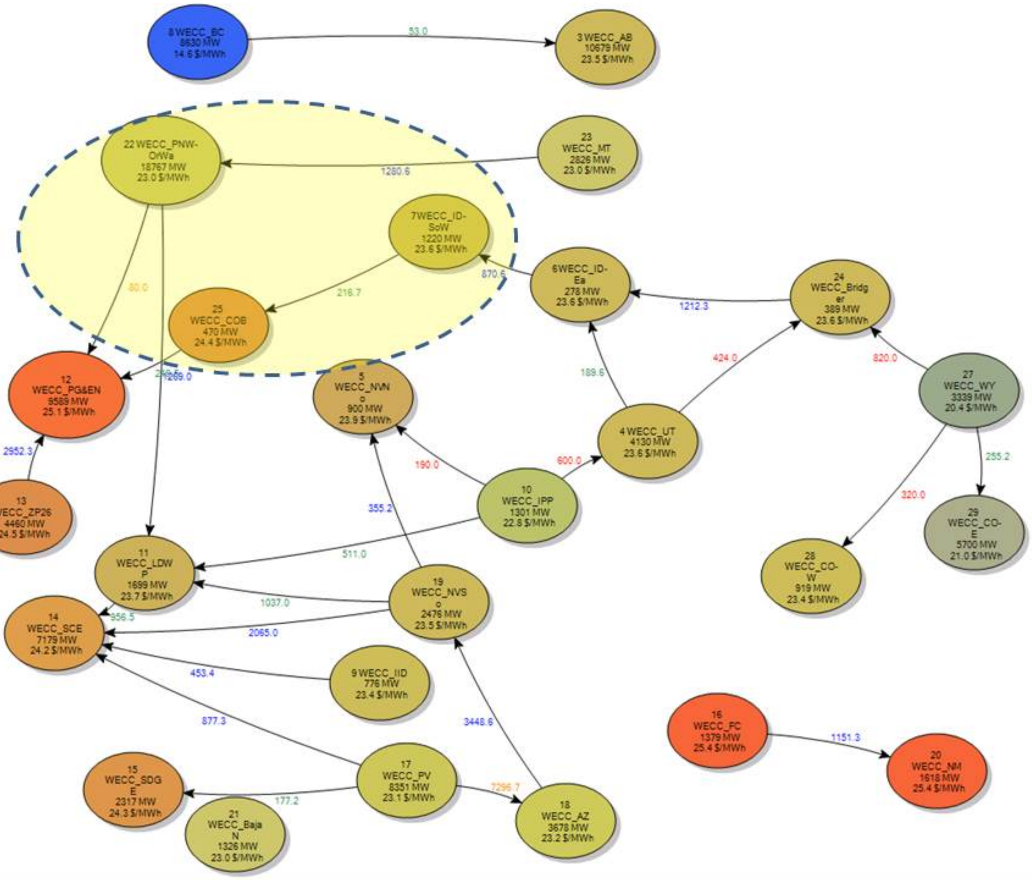
The WECC topology PGE uses in this IRP (see Figure 10-1), represents an hourly snapshot of the WECC transactions to meet regional load. It reveals that:

- Figure 10-1 shows the WECC divided in 26 zones represented by bubbles. The three zones highlighted in yellow represent the Pacific Northwest: 1) Oregon-Washington, 2) California-

Oregon Border (COB), and Southwest Idaho (ID-SoW). For modeling purposes, PGE ignores transmission constraints within a zone, and only enforces transmission constraints between zones.

- PGE uses Aurora to develop an electricity price for each zone in each hour. In Figure 10-1, each bubble shows this electricity price, along with the total load for that hour. AURORA allows imports and exports between zones up to the capacity of the transmission lines connecting two zones. When the price of imports is below generation, AURORA selects the imports to meet zonal demand up to the transmission limit. The connecting arrows in Figure 10-1 show the resulting flows.

FIGURE 10-1: WECC topology - example of hourly interchange



In this IRP, PGE adopted a two-step approach to regional modeling:

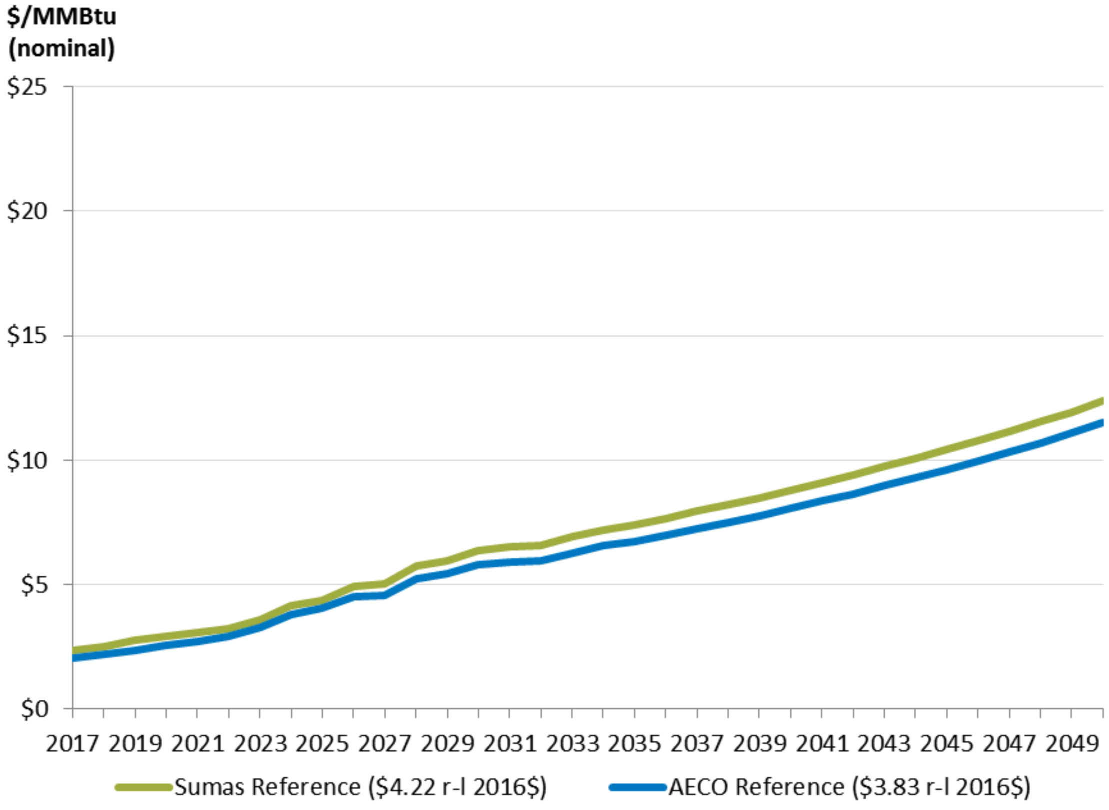
1. PGE selected the Wood Mackenzie regional capacity expansion to 2035 for use as the default resource database;
2. PGE updated costs and constraints for future WECC resources and simulated new capacity expansions to 2050, the final year of analysis in this IRP, based on CO_2 regime. The following sections provide more detail on incorporated updates.

10.2.1.2 Reference Case and Additional Regional Capacity Expansion Futures

PGE bases the Reference Case future on the expected assumptions pertaining to resource costs (e.g., capital, O&M), market prices, governmental policies and regulation, and other conditions. The Reference Case is the "base case" set of assumptions for all candidate portfolios, and is also the baseline for testing portfolio performance under alternate future conditions (futures). The following section summarizes the key inputs used in the Reference Case.

- **Commodity fuel price.** Natural gas prices at AECO are approximately $3.83 per MMBtu (real levelized 2016 dollars for the period 2017-2050). PGE uses Wood Mackenzie for the long-term forecast, along with additional research. The Company uses market quotes for the near-term prices through 2020. More details regarding fuel prices are available in Chapter 3, Planning Environment. Figure 10-2 presents the Reference Case natural gas prices for Sumas and AECO on a nominal dollar per MMBtu basis through 2050.

FIGURE 10-2: PNW reference case natural gas prices 2017-2050 (nominal $/MWh)



- **Fuel transportation cost.** Pacific Northwest (PNW) natural gas transport costs rely on current rates, with escalation at inflation going forward.
- **Renewable resource tax credits.** PGE uses the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), as applicable in the First Quarter (Q1) of 2016, for all qualifying renewable resources. Both credits are subject to phasedown in the near future.[195]

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[195] See Chapter 3, Planning Environment.

- **Transmission cost to PGE's system.** PGE uses BPA's published transmission tariff rates as of Q1 2016 (with escalation) for all new generating resources within the PNW. Further discussion of transmission considerations is available in Chapter 9, Transmission Options.
- **PGE load.** PGE uses the base case long-term load growth forecast described in Chapter 4, Resource Need. Under this forecast, long-term load growth averages 1.2 percent per year from 2022 through 2050.
- **Environmental assumptions.** Chapter 3, Planning Environment, provides the details of PGE's environmental assumptions. In addition to compliance with all existing regulations in the WECC, British Columbia, and Alberta, PGE models the presence of EPA's Clean Power Plan constraints using a limit on the total tons of CO_2 that qualifying units may emit annually, also known as a mass-based standard.
- Additionally, PGE reflects a national CO_2 emission allowance trading scheme that results in an effective price of CO_2 emissions beginning in 2022 equivalent to approximately $22.50 per short ton (all dollar amounts and growth rates are nominal unless otherwise noted). This effective CO_2 price, consistent with Synapse Energy Economics' "Mid Case" as published in the, "Spring 2016 National Carbon Dioxide Price Forecast" escalates at five percent annually through 2030 and eight percent annually thereafter for the duration of the analysis horizon. As discussed in Chapter 3, Planning Environment, this "Mid Case" reflects an environment in which "Clean Power Plan compliance is achieved and science-based climate targets mandate at least an 80 percent reduction in electric section emissions from 2005 levels by 2050."[196] Figure 10-3 portrays the Reference Case CO_2 price assumption for all resources in the WECC.[197]

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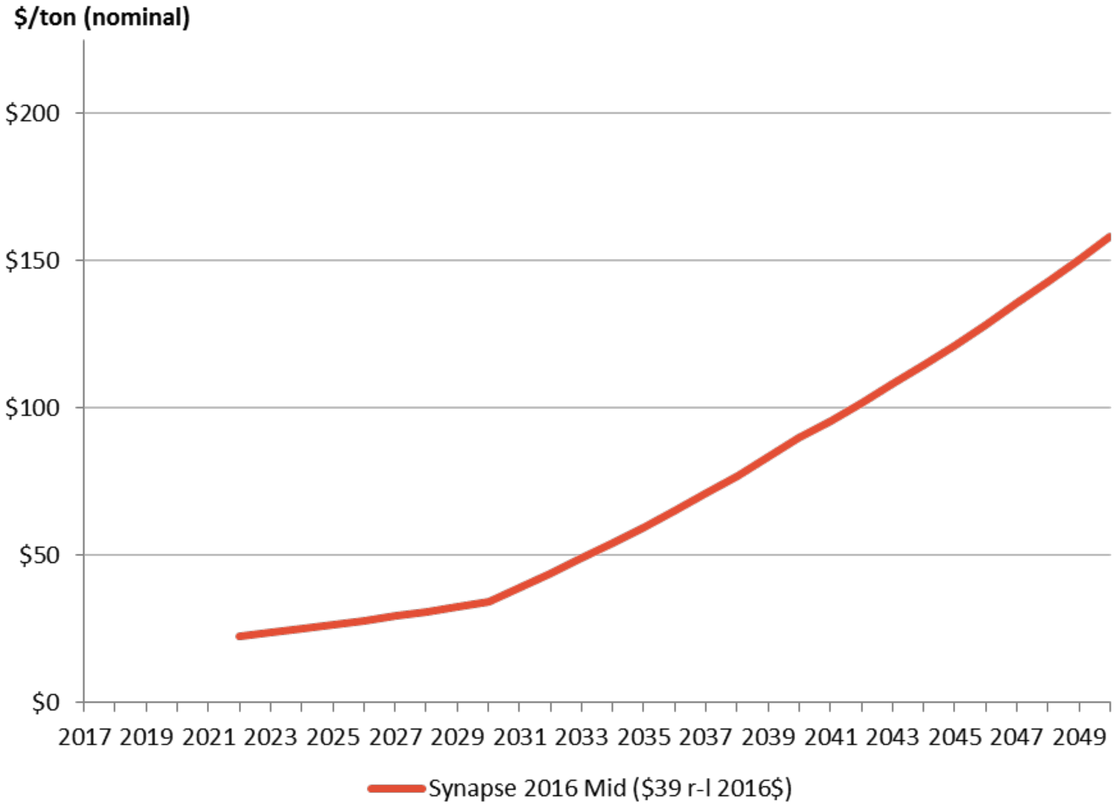
[196] "Spring 2016 National Carbon Dioxide Price Forecast." Dated March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008_0.pdf

[197] This price replaces state-level CO_2 emissions costs beginning in 2022.

FIGURE 10-3: PNW reference case CO_2 emissions prices 2017-2050 (nominal $/ton)



10.2.1.3 Regional Resource Modeling Assumptions

For purposes of modeling, the WECC long-term wholesale electricity market is subject to the following criteria:

- Fuel price assumptions are consistent with the Wood Mackenzie long-term forecast mentioned above and discussed in detail in Chapter 3, Planning Environment.
- Environmental constraints align with the assumptions discussed above.
- Reliability standards add sufficient resources in the WECC to meet expected peak loads, plus reserves ranging from 12 percent to 15 percent in the long-run, depending on the zone.
- The regional resource stack reflects known and expected resource additions and retirements. The research of third-party consultants informs potential future regional resource actions. AURORA allows resource retirements based on resource economics simulated in the model.
- PGE applies RPS standards in all WECC states that currently have renewable resource requirements, including Oregon's recent 50 percent RPS requirements for 2040 as set forth in SB 1547. Table 10-2 below summarizes the state RPS targets incorporated into PGE's regional assumptions. PGE assumes the 2040 RPS standards in Table 10-2 apply through the end of the analysis time horizon for this IRP (2050).

TABLE 10-2: WECC state RPS targets

	2020	2025	2030	2035	2040
Arizona	10%	15%	15%	15%	15%
California	33%	40%	50%	50%	50%
Colorado	30%	30%	30%	30%	30%
Montana	15%	15%	15%	15%	15%
Nevada	22%	25%	25%	25%	25%
New Mexico	20%	20%	20%	20%	20%
Oregon*	20%	27%	35%	45%	50%
Washington	15%	15%	15%	15%	15%

*Large 'Electric Companies' & ESS

As required by Guideline 1a of Order No. 07-047, PGE's estimated after-tax marginal weighted-average cost of capital of 6.20 percent serves as a proxy for the long-term cost of capital in the WECC. PGE bases this estimate on information available as of Q1 2016. Table 10-3 contains other relevant financial assumptions.

TABLE 10-3: PGE's long-term financial assumptions

Component	%
Composite Income Tax Rate	40.00%
Incremental Cost of Long-term Debt*	4.68%
Long-term Debt Share of Capital Structure	50.00%
Common Equity Return	9.60%
Common Equity Share of Capital Structure	50.00%
Weighted Cost of Capital	7.14%
Weighted After-Tax Cost of Capital	6.20%
Long-Term General Inflation	2.00%

*Incremental Cost of Long-term Debt is based on an average of three-year forward 30-year borrowing costs (i.e., the cost of 30-year debt in 2016, 2017, 2018).

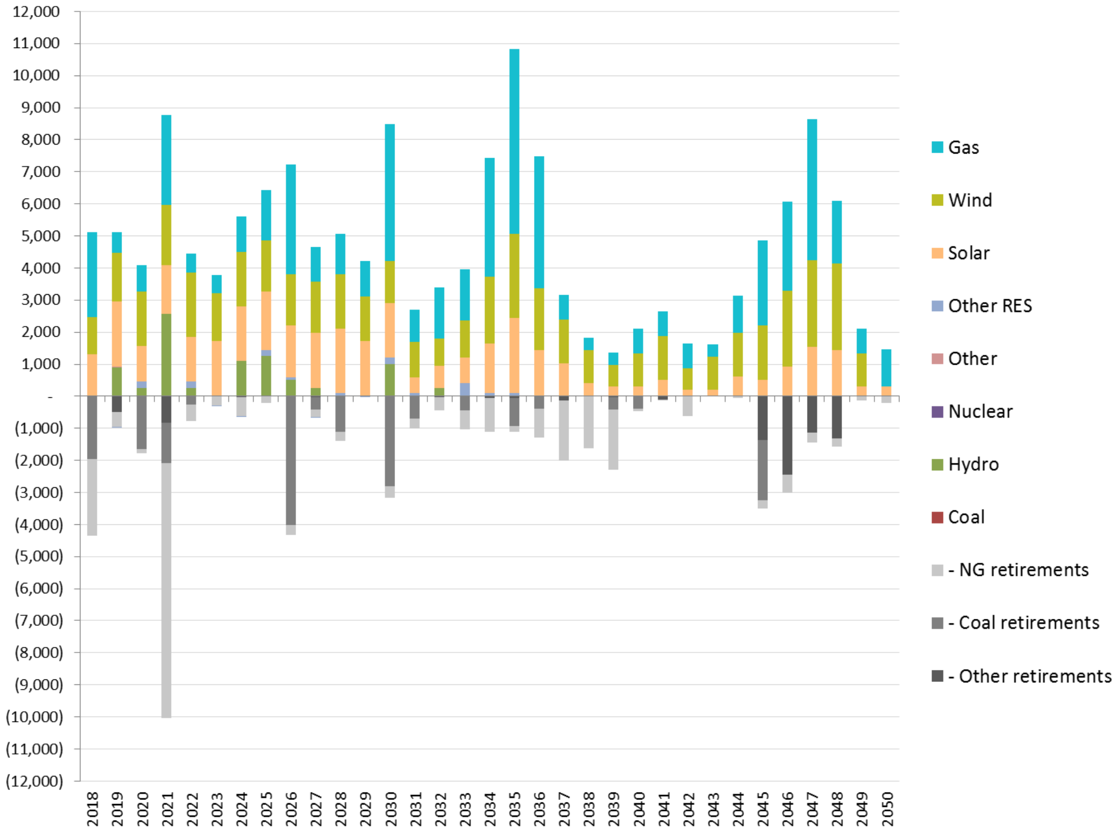
AURORA adds new generating resources at their typical plant size, based on the resource cost and performance parameters discussed in Chapter 7, Supply Options. New resource additions, which are typically large, thus cause temporary over-supply conditions until load growth catches up to new, "lumpy" resource additions.

The assumptions PGE imposes on AURORA, while reasonably constraining the model to meet reliability standards over the long-term, do not reflect the discretion of individual utilities and market participants to deviate from these norms. AURORA's assumptions also do not inherently recognize that supply imbalances occur in the short-run and can cause reserve margins to shrink, resulting in scarcity and market prices that can dramatically exceed fully-allocated costs.

Figure 10-4 portrays resource additions and retirements by fuel type over the study period for PGE's Reference Case assumptions. It shows thermal plant retirements for all fuel sources: gas, fuel oil, nuclear[198] and coal plants, and additions dominated by renewables and gas plants. By 2050 (the last year of PGE's analysis), gas and renewable plants, respectively 35 percent and 40 percent of the total nameplate capacity installed, dominate the WECC resource mix based on total average capacity. Hydro is 21 percent, nuclear is retired and coal drops from the current 14 percent to four percent.

For more detail, see Appendix N, WECC Resource Expansion Detail.

FIGURE 10-4: Resource additions and retirements by fuel type



Hourly market prices simulated in AURORA represent the marginal cost of generating an additional unit of power within each hour. By definition, these simulated market prices do not include consideration for return-on and -of invested capital or fixed cost components associated with

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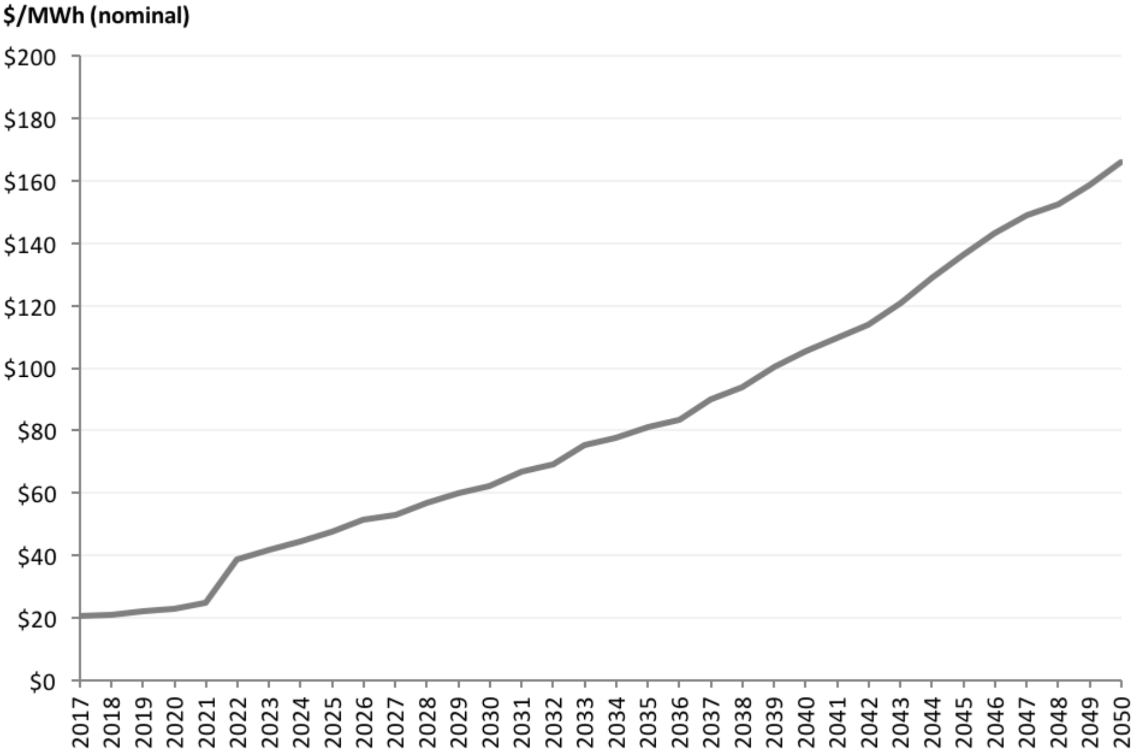
[198] Nuclear retirements are included in the "Other retirements" category in Figure 10-4.

operating a generating resource. AURORA prices surplus power (relative to demand) at the short-run marginal cost and trades this power (if economic) until reaching transmission limits.

Figure 10-5 shows the resulting average annual (or flat) electricity market price projection for the Pacific Northwest using the Reference Case assumptions above-described. Appendix H, AURORA Market Prices, provides additional details.

FIGURE 10-5: PNW reference case electricity prices 2017-2050 (nominal $/MWh)



The WECC build-out is the result of specific assumptions regarding factors such as fuel prices, carbon policy, and investment costs. As it is impractical to adjust the WECC resource mix for every combination of changes to fundamental market assumptions, PGE focuses on potential CO_2 costs as the driver for changes to the regional resource mix in IRP modeling.

That is, PGE simulated two additional WECC capacity build-outs by assuming:

- No explicit carbon costs in the WECC, yet CPP constraints remain in-place; and,
- High CO_2 cost assumptions.

This adjustment is necessary because market participants will choose to pursue the most economic actions given the expected conditions. PGE uses the resulting WECC resource mixes for the simulation of electricity prices and the dispatch of all power plants in the WECC when performing scenario analyses that include the corresponding CO_2 price environment.

10.3 Futures

Once the WECC fundamental build-outs are simulated, the next step in PGE's analysis is to generate electricity prices and expected plant dispatch by changing sets of deterministic input variables that describe a variety of potential circumstances. These deterministic input variables ultimately drive the economic performance of resources over the planning horizon. PGE assesses multiple futures in order to test the performance of candidate portfolios, which is the final step of portfolio analysis.

The set of futures is broad and diverse, reasonably reflecting the types of changing circumstances that could be encountered and the resulting impact on the cost and risk of various portfolio choices. In particular, PGE ensures that its futures test the robustness of each candidate portfolio against possible changes in underlying fundamentals that could result in large changes in energy market prices or significantly impact the cost or value of the resources within the portfolio.

PGE created 23 futures to use for portfolio evaluation:

- **Reference Case:** The reference case includes the base assumptions for load, gas prices, and CO_2 prices (see Section 10.2.1.2, Reference Case and Additional Regional Capacity Expansion Futures, above).
- **High Natural Gas Prices:** The "High" natural gas price is $6.54 per MMBtu at AECO (real levelized 2016$ for the period 2017-2050). PGE bases this long-term scenario on the “High Oil Price” scenario presented by the Energy Information Administration (EIA) in their 2015 Annual Energy Outlook.[199] Figure 10-6 represents the Reference Case natural gas prices for Sumas and AECO on a nominal dollar per MMBtu basis through 2050. Figure 10-6 provides the High Case natural gas prices for Sumas and AECO on a nominal dollar per MMBtu basis through 2050, along with the Reference Case assumptions for comparison purposes. Chapter 3, Planning Environment, provides additional details regarding the long-term natural gas price forecast.

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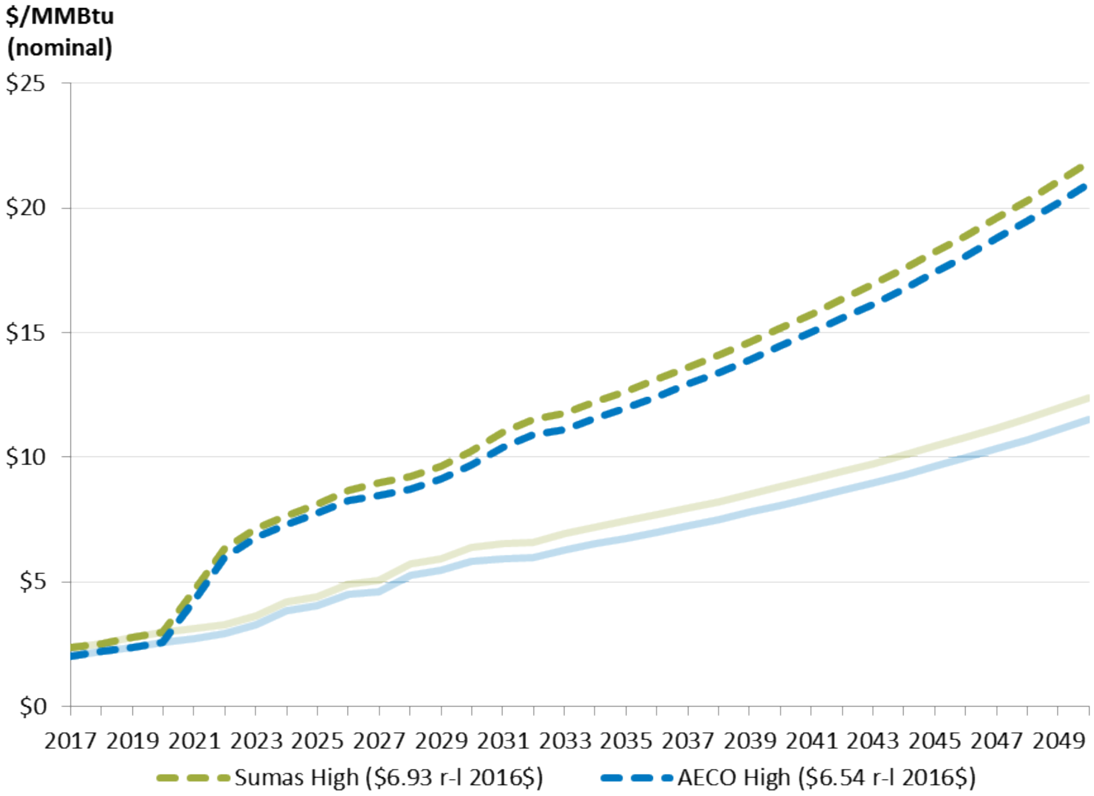
[199] http://www.eia.gov/forecasts/archive/aeo15/tables_ref.cfm

FIGURE 10-6: PNW high case natural gas prices 2017-2050 (nominal $/MWh)



- **No CO_2:** This case reflects a future state in which CO_2 emissions do not incur explicit costs, yet CPP constraints remain in effect (state and provincial CO_2 regimes remain in place).
- **High CO_2:** This case includes a CO_2 price that is $28 per short ton (nominal) starting in 2022 and escalating at six percent annually through 2027 and eight percent annually thereafter through 2050. This effective CO_2 price is consistent with Synapse Energy Economics' (Synapse) "High Case." This "High Case" reflects an environment with, "a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2027. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector." This scenario may also be representative of other elements leading to higher costs of emissions reductions, such as, offset use restrictions, high cost of resource alternatives, and additional international actions.[200] Figure 10-7 provides the High Case CO_2 prices, as well as the Reference Case (the Synapse 2016 "Mid" case).

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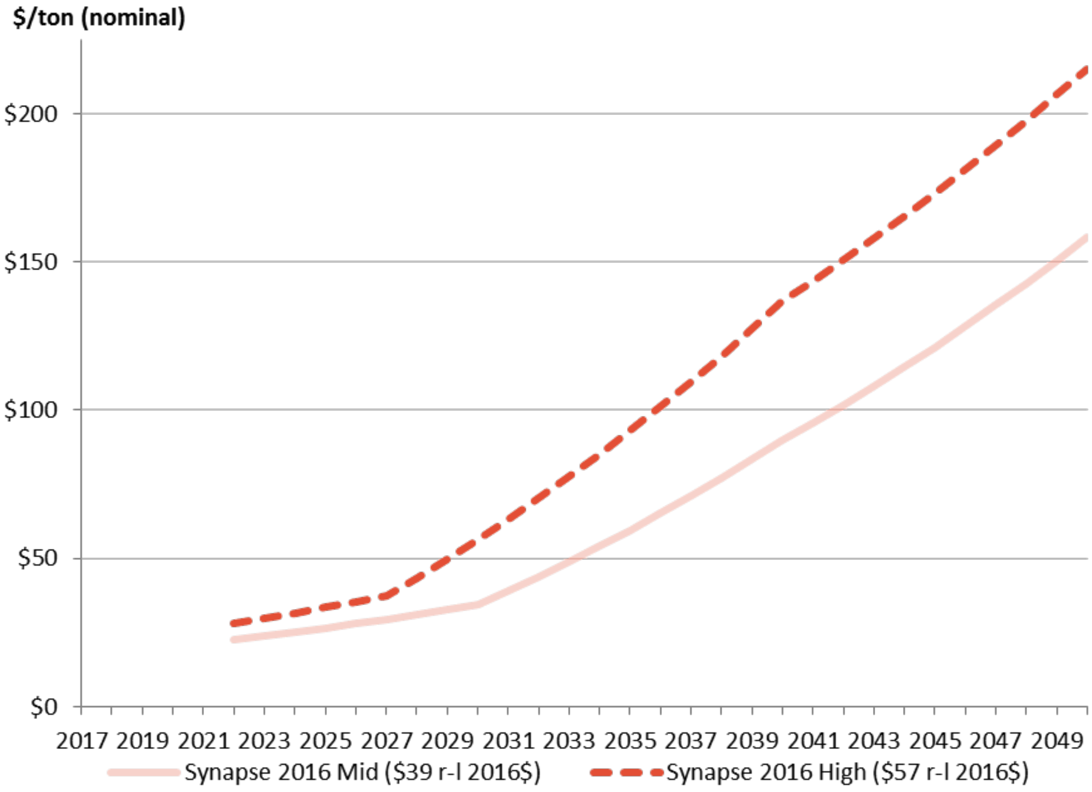
[200] "Spring 2016 National Carbon Dioxide Price Forecast." Dated March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008_0.pdf

FIGURE 10-7: High case CO_2 prices 2017-2050 (nominal $/MWh)



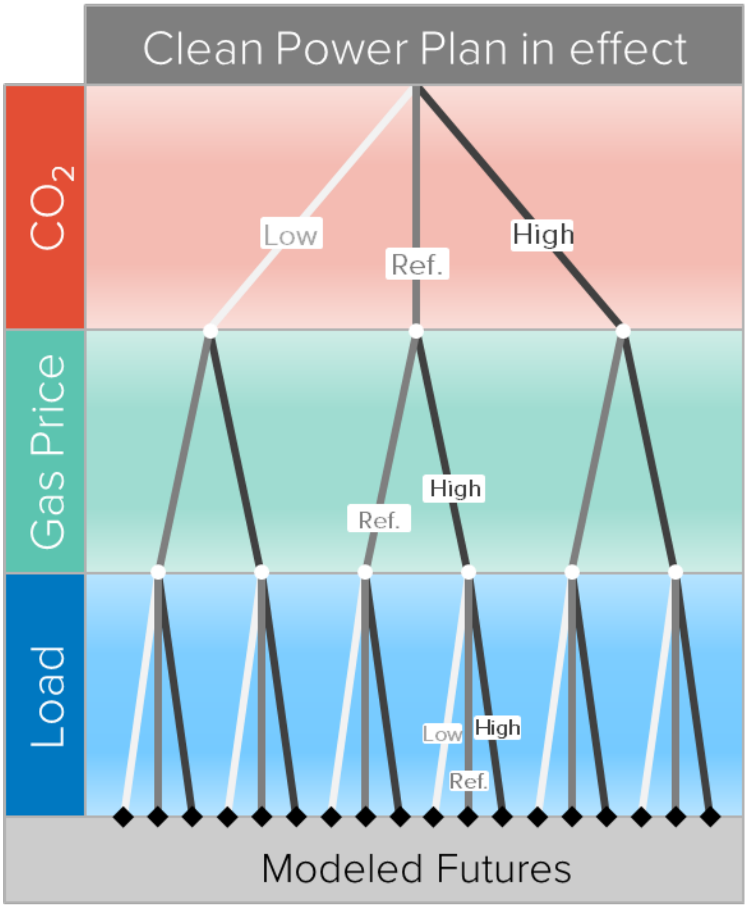
Refer to Chapter 3, Planning Environment, for a discussion of carbon regulation and PGE's assumptions regarding Clean Power Plan implementation.

The following represent PGE's long-term load growth futures, in addition to the Reference Case:

- **Low Load Growth Rate:** 0.6% compound annual average growth between 2017 and 2050.
- **High Load Growth Rate:** 1.8% compound annual average growth between 2017 and 2050.

Figure 10-8 illustrates the main drivers of PGE's futures: CO_2 prices, natural gas prices, and portfolio load. Combining the three CO_2 price futures, two gas price futures, and three load growth futures, results in 18 futures tested based on these risk factors.

FIGURE 10-8: PGE core futures and risk drivers



In addition to the 18 futures based on the three key risk drivers depicted in Figure 10-8, PGE pairs other discrete risk factors with Reference Case inputs. The Company models each of the following factors in conjunction with its Reference Case assumptions for natural gas prices, CO_2 emission prices, and load growth:

- **Capital cost futures** aimed at quantifying the consequences of incurring investment costs higher or lower than the costs described in Chapter 7, Supply Options:
    - High capital costs for all resources: overnight capital costs estimated by third-party consultants as being approximately one standard deviation higher than the Reference Case.
    - Low capital cost for all resources: overnight capital costs estimated by consultants as being approximately one standard deviation lower than the Reference Case assumption.
- **Renewable resource generation** futures aimed at quantifying the consequences of generating more or less energy from new renewable resources than the Reference Case assumptions described in Chapter 7, Supply Options:

    - High capacity factor for new wind and solar resources: annual generation is approximately ten percent greater than the Reference Case assumption developed by third-party consultants.
    - Low capacity factor for new wind and solar resources: annual generation is approximately ten percent less than reflected under Reference Case conditions.
- **Low PNW hydro** simulating 1937 critical hydro conditions in the PNW.

10.4 PGE's Resource Portfolio Design

As mentioned at the outset of this chapter, the goal of the IRP is to identify a mix of resources that, in conjunction with PGE's existing resource portfolio, provides the best combination of expected costs and associated risks and uncertainties for PGE and its customers. PGE refers to these resource mixes as portfolios. The Company's first step in developing candidate portfolios is to identify the resource gaps, as detailed in Chapter 5, Resource Adequacy, and then assess the possible resource combinations to meet the resulting needs. Chapter 6, Demand Options, and Chapter 7, Supply Options, discuss the resources PGE considered for inclusion in its resource portfolios.

10.4.1 Portfolio Construction Methodology

As discussed in Chapter 6, Demand Options, PGE plans to meet a growing portion of its resource needs through demand-side resources. This primarily includes energy efficiency (EE), as projected by the Energy Trust of Oregon (Energy Trust) and demand response (DR). In addition, PGE plans to expand its Dispatchable Standby Generation (DSG) program to meet the growing non-spin need.[201]

For the remaining portfolio needs not met by demand-side resources and DSG, PGE includes supply-side resources with the following methodology:

- Renewable resources necessary to maintain compliance with the Oregon Renewable RPS through 2050. Section 10.6, RPS Compliance Strategies, provides a detailed discussion on RPS and PGE's compliance strategy.
- Capacity resources to maintain resource adequacy through 2050 (with the exception of the *RPS Wind 2018 + No Capacity Action* portfolio). For modeling purposes, PGE inputs these resources as gas fired turbines (frame units or CCCTs).
- PGE includes only supply-side resources that are commercially available, geographically accessible, and for which there are no legal constraints. These criteria eliminate the following options:
    - Coal-fired resources (traditional, with carbon capture, and integrated gasification combined cycle (IGCC)) are all ineligible to be included with electricity allocated to retail electricity customers in the state of Oregon consistent with the language of SB 1547.
    - Nuclear power plants do not qualify because of the Oregon ban on new nuclear plants prior to the construction of a federal nuclear waste repository facility.

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[201] PGE's DSG program is described in Section 7.1.4, Dispatchable Standby Generation.

A number of portfolios test the effect on total portfolio cost of changing the date on which PGE removes Colstrip Units 3 & 4 from its retail resource portfolio. In those portfolios, PGE also compares the costs and benefits of different replacement resources.

10.4.2 Resource Adequacy and Capacity Contribution

This IRP introduces for the first time a reliability constraint in developing portfolios. PGE modeled this constraint using the RECAP model described in Chapter 5, Resource Adequacy, with the goal of constraining to 2.4 hours a year the maximum hours of unserved load. As discussed in Section 5.1, Capacity Adequacy and Capacity Contribution, PGE assesses capacity need after the inclusion of resource actions common to all portfolios (EE, DR, DSG).

PGE next adds all additional resources (excluding generic capacity) to the portfolio according to the different portfolio designs discussed later in Section 10.5, Portfolios Analysis. The Company then assesses the remaining portfolio total capacity need and uses a generic capacity resource to meet this need. PGE models the cost and performance parameters of the generic capacity resource on those of a frame CT (GE 7FA.05). (See Chapter 7, Supply Options, for a more detailed discussion of the cost and performance parameters for PGE's generic capacity resource.)

With the exception of the *RPS Wind 2018 + No Capacity Action* portfolio (which contains no additional resource additions beyond RPS actions), PGE constructed its resource portfolios to satisfy the resource adequacy expectation discussed in Chapter 5, Resource Adequacy.

10.5 Portfolios Analysis

Similar to the portfolio approach used in prior IRPs, PGE designed "pure play" portfolios (incremental portfolios focusing on a single resource type) for the 2016 IRP, which the Company then builds on to test portfolios that vary resource quantity, timing, and diversification. This approach allows PGE to examine, with the intent of isolating, the performance differences of various resource types, as well as the potential cost and risk implications of portfolio compositions. PGE includes certain portfolios in an attempt to answer specific questions. For example, PGE modeled *Diverse Wind 2018* to assess how much the Company would be willing to spend on new transmission to Montana in order to access more efficient wind sites. Such portfolios serve to guide PGE's decisions, but PGE does not consider them in its comprehensive portfolio scoring.

All portfolios share in common deployment of the EE, demand response, DSG, and CVR through 2050. The following list summarizes the actions for 2017-2025.[202] See Appendix O, Portfolio Detail, for additional information.

- 239 MWa (297 MW) of new EE,[203]
- 162 MW of new demand response,
- 30 MW of DSG, and
- 3 MWa (4 MW) of CVR.

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[202] All amounts at the busbar and represent annual average generation in MWa and average annual capacity in MW in 2025.

[203] Represents EE achieved on average across 2025, which is slightly less than the EE achieved by year end.

To meet RPS standards, most portfolios add a minimum of 213 MWa of qualifying resources by 2025.[204] The resource portfolios also incorporate the principals of RPS bank management discussed in Section 10.6.4, Considerations for REC Bank Management. As such, the timing of RPS resource acquisition effects the RPS resource quantities needed in future years. Several portfolios are included to test the potential benefits associated with the ability to procure unbundled RECs.

Appendix O, Portfolio Detail, shows the annual detail by portfolio and resource type.

A description of each portfolio follows:

1. **RPS Wind 2018 + No Capacity Action.** In addition to the common resource actions, this portfolio adds PNW Wind resources in 2018 and on each compliance stair-step date thereafter, adding: 175 MWa in 2018, 38 MWa in 2025, 43 MWa in 2030, 597 MWa in 2035, 191 MWa in 2040, and 92 and 102 MWa in 2045 and 2050, respectively. This portfolio does not include any additional resource actions. All incremental energy needs are met with spot market purchases. This portfolio does not meet reliability standards and is therefore not a viable strategy for PGE.
2. **RPS Wind 2018.** This portfolio is similar to *Portfolio 1*, but includes sufficient generic capacity resources in each year to achieve PGE's resource adequacy standards. Generic capacity is represented by the cost and heat rate characteristics of a natural gas-fired frame combustion turbine, which has reduced fixed costs and a higher heat rate compared to efficient capacity (*Portfolio 3*).
3. **Efficient Capacity 2021.** This portfolio is equivalent to *Portfolio 2 – RPS Wind 2018*, with a portion of the generic capacity in 2021 replaced by a resource with higher fixed costs and a lower heat rate. The efficient capacity resource is modeled as a natural gas-fired CCCT with an average annual capacity of approximately 389 MW. This portfolio allows PGE to assess the potential costs/benefits of relying on a low-heat rate resource to meet capacity needs.
4. **Wind 2018 Long.** This portfolio is similar to *Portfolio 3 – Efficient Capacity 2021*, but achieves the same expected available energy and capacity by adding PNW Wind and generic capacity in 2021 as opposed to a CCCT. Following the 175 MWa wind resource action in 2018, *Portfolio 4 – Wind 2018 Long* adds 369 MWa of wind and 374 MW of generic capacity in 2021. Both early renewable additions defer later RPS actions through accumulated banked RECs. This portfolio is included for comparison purposes with *Portfolio 3* to assess the relative cost/benefit of a portfolio composed of PNW Wind relative to a natural gas-fired CCCT resource.
5. **Wind 2018.** This portfolio is similar to *Portfolio 4*, but rather than adding wind in a quantity equivalent to a CCCT on an expected annual average energy basis in 2021, PGE includes a wind resource sized just to satisfy the available energy deficit in that year (approximately 213 MWa). The portfolio adds additional generic capacity in 2021 to achieve resource adequacy.
6. **Diverse Wind 2021.** This portfolio is identical to *Portfolio 6 – Wind 2018*, but adds Montana Wind instead of PNW Wind in 2018 and 2021, with the wind resources sized to add the same energy as those in *Portfolio 5*. Due to Montana Wind's capacity factor and capacity

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[204] Excluding *Portfolios 22* and *23*.

contribution, less wind capacity is required and less generic capacity is needed beginning in 2021. When compared with *Portfolio 6*, this portfolio allows PGE to estimate the costs and benefits of Montana Wind, including a Montana transmission infrastructure budget (if transmission were necessary to access a remote resource). Chapter 12, Modeling Results, provides the results of that comparison.

7. **Wind 2018 + Solar PV 2021.** Including 50 MWa of Solar PV in 2021 in this portfolio allows PGE to explore the potential benefits of displacing a portion of the PNW Wind resource with Solar PV. Solar PV's increased capacity contribution allows this portfolio to require less generic capacity in 2021. The Solar PV resource, online January 1, 2021, qualifies for 26 percent ITC based on IRP modeling assumptions.

8. **Geothermal 2021.** This portfolio adds a 30 MW geothermal resource in 2021, displacing 27 MWa of 2021 PNW Wind compared to *Portfolio 5 – Wind 2018*. Additionally, the geothermal resource reduces the quantity of generic capacity added in 2021. This portfolio provides PGE with a means to weigh the potential benefits of a non-variable renewable resource compared to PNW Wind.

9. **Boardman Biomass 2021.** The Boardman Biomass portfolio is constructed from *Portfolio 5 – Wind 2018*; however, in 2021, the portfolio includes the Boardman Biomass Project (570 MW) and does not include additions for PNW Wind or generic capacity. Additionally, generic capacity additions are avoided in 2022-2024 and reduced in 2025. This portfolio provides PGE with a means to weigh the potential benefits of a seasonal non-variable renewable resource compared to PNW Wind and further investigate the cost-effectiveness threshold for this project.

The following portfolios include modifications to those mentioned previously.

10. **Wind 2018 + Solar PV 2018.** This portfolio is similar to *Portfolio 7 – Wind 2018 + Solar PV 2021*, but it displaces 50 MWa of the PNW Wind resource addition with Solar PV in 2018, rather than 2021. The slight timing change results in the inclusion of a Solar PV resource that receives the full 30 percent ITC, while displacing wind that qualifies for 100 percent PTC. The generic capacity additions are adjusted to reflect the earlier addition of Solar PV.

11. **Efficient Capacity 2021 + High EE.** This portfolio is similar to *Portfolio 3 – Efficient Capacity 2021*, except for procuring additional EE to the Energy Trust's All Achievable EE forecast. Including All Achievable EE displaces portions of the energy, capacity, and RPS requirements in the portfolio. All Achievable EE is discussed in Section 6.1, Energy Efficiency.

12. **Wind 2018 + High EE.** This portfolio is similar to *Portfolio 5 – Wind 2018*, except for procuring additional EE to the Energy Trust's All Achievable EE forecast. Including All Achievable EE displaces portions of the energy, capacity, and RPS requirements in the portfolio.

The following portfolios use *Portfolio 2 – RPS Wind 2018* as the starting point to reflect the effects of various dates for removing Colstrip Units 3 & 4 from PGE's retail resource portfolio, as well as various replacement resources. *Portfolio 2* removes Colstrip Units 3 & 4 from the portfolio at year-end of 2034 and includes sufficient generic capacity additions in 2035 to achieve resource adequacy.

13. **Colstrip Wind 2030.** This portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2029, and replaces them on an equivalent expected energy basis with the Montana Wind resource discussed previously. Generic capacity is also included to achieve resource adequacy.
14. **Colstrip Wind 2035.** This portfolio serves as a comparison with *Portfolio 13*. The portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2034 and replaces them, on an equivalent expected energy basis, with Montana Wind. Generic capacity is included to achieve resource adequacy. Together, *Portfolio 13* and *Portfolio 14* aim to inform the relative costs/benefits of a relatively earlier or later date for removal of Colstrip Units 3 & 4 from PGE's resource portfolio when considering remote wind as the replacement resource.
15. **Colstrip Efficient Capacity 2030.** Similar to *Portfolio 13*, this portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2029, but replaces them with an H-class CCCT rather than a wind resource. The portfolio also adds generic capacity resources as needed to achieve resource adequacy. Using *Portfolio 13* as the comparator provides insights regarding the potential relative costs/benefits of a CCCT as the replacement resource versus remote wind after accounting for timing effects.
16. **Colstrip Efficient Capacity 2035.** This portfolio provides a comparison with *Portfolio 14* and *Portfolio 15*. The portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2034, and replaces them with an H-class CCCT rather than a wind resource. The generic capacity additions are also adjusted to achieve resource adequacy. Together, *Portfolio 15* and *Portfolio 16* aim to inform the relative costs/benefits of a relatively earlier or later date for removal of Colstrip Units 3 & 4 from PGE's resource portfolio when considering remote wind as the replacement resource. When compared with *Portfolio 14*, PGE again learns about the potential relative costs/benefits of a CCCT as the replacement resource versus remote wind after accounting for timing effects.

The following portfolios test various RPS strategies relative to PGE's baseline recommendation of 175 MWa of wind in 2018, as previously mentioned.

17. **RPS Wind 2020.** This portfolio adopts a strategy of complying with long-term RPS qualifying resources in size and timing consistent with the respective RPS stair-steps, adding PNW Wind through 2035 as follows: 31 MWa in 2020, 183 MWa in 2025, 258 MWa in 2030, and 383 MWa in 2035, 191 MWa in 2040, and 92 and 102 MWa in 2045 and 2050, respectively. Generic capacity additions are included as needed to achieve resource adequacy in each year.
18. **RPS Wind 2025.** This portfolio tests a strategy of deferring RPS long-term qualifying resource additions. In lieu of 2018 or 2020 resource actions, the first incremental RPS qualifying resource addition in this portfolio is a 213 MWa PNW Wind resource in 2025. Through 2035, this portfolio adds PNW Wind as follows: 213 MWa in 2025, 288 MWa in 2030, and 352 MWa in 2035. Additions post-2035 are identical to *Portfolio 17*. Generic capacity additions are included as needed to achieve resource adequacy in each year. Relative to PGE's baseline assumption or the compliance stair-step assumption described in *Portfolio 17*, PGE expects this portfolio to receive a benefit on an NPV basis arising from the deferral of expenditure. However, deferring RPS action to 2025 accelerates resource additions on the back-end of

the modeling time horizon in order to bring the REC bank to a position comparable to other strategies.

19. **RPS Wind 2021.** Similar to *Portfolio 18* in terms of the size of the first incremental RPS qualifying resource addition, this portfolio adds 213 MWa of PNW Wind in a single year. In this portfolio, however, the addition occurs in 2021, allowing the assumed wind resource to qualify for the final tranche of PTC benefit at the 40 percent level based on IRP modeling assumptions. Generic capacity additions are included as needed to achieve resource adequacy in each year. Relative to *Portfolio 18*, the earlier resource addition here results in an ability to defer resource additions to 2035 while maintaining a comparable REC bank position.
20. **Efficient Capacity 2021 Minimum REC Bank.** This portfolio studies an alternative RPS compliance strategy making full and immediate use of PGE's existing banked RECs. When compared to *Portfolio 3 – Efficient Capacity 2021*, this portfolio does not achieve physical RPS compliance by 2025. Additionally, this portfolio foregoes the opportunity to capture the 100 percent PTC benefit with a qualifying RPS resource addition in 2018. This portfolio delays incremental RPS resource actions until 2025 in order to deplete the REC bank to its minimum recommended level. The first RPS resource addition is 181 MWa in 2025 sized to meet the minimum recommended REC bank by year end 2029. RPS resources providing 353 MWa and 320 MWa in 2030 and 2035, respectively, are then required. The delay in RPS additions also impacts the generic capacity additions needed to achieve resource adequacy. *Portfolio 20* can be compared with *Portfolio 3* to gain information regarding the potential costs/benefits of foregoing the 100 percent PTC resource in favor of deferring incremental RPS resource actions without relying on unbundled RECs.
21. **Efficient Capacity 2021 20% Unbundled RECs.** Similar to *Portfolio 20*, this portfolio defers incremental RPS resource actions until 2025. However, this portfolio includes an assumption that sufficient unbundled RECs are available to fill 20 percent of PGE's annual RPS obligation during the period 2016–2021. The unbundled RECs are not assigned an explicit cost in the portfolio. The 2025 RPS resource addition represents 98 MWa to satisfy PGE's minimum REC bank requirement. This portfolio includes subsequent RPS resource additions of 436 MWa in 2030 and 320 MWa in 2035. The generic capacity additions are adjusted compared to portfolio #22 due the changes in RPS additions in 2025 and 2030. Comparing *Portfolio 3 – Efficient Capacity 2021* and *Portfolio 21* provides information regarding the potential costs/benefits of pursuing a strategy that both defers RPS resource actions and relies on unbundled RECs relative to a strategy that procures a 100 percent PTC qualifying resource. Furthermore, a comparison of *Portfolio 20* and *Portfolio 21* allows PGE to approximate a break-even price for unbundled RECs, given a strategy to draw the REC bank to its minimum recommended level.

The resource portfolios PGE tests in this IRP effectively explore the range of potential, realistic options that are available. For more discussion on those options, please refer to Chapter 7, Supply Options.

Appendix O, Portfolio Detail, summarizes the total resource additions by portfolio and resource type.

10.5.1 Scenario Analysis

Scenario analysis provides the framework for assessing the economic risks associated with the different portfolios. As stated above, PGE refers to those risk factors, either in isolation or in combination with one another, as "futures". PGE constructs futures to examine portfolio performance under varying potential environments. PGE then tests each portfolio against each future and computes the NPVRR for each portfolio/future combination.

Chapter 11, Scoring Metrics, describes how PGE scores portfolios from best to worst, based on the results of scenario analysis. Chapter 12, Modeling Results, reports in detail the result of PGE's portfolio analysis and highlights specific risk metrics required by the IRP guidelines.

10.5.2 Reliability Analysis Methodology

See the discussion in Chapter 5, Resource Adequacy, for information related to PGE's resource adequacy framework. PGE uses the same tools and framework discussed in that section to test portfolio reliability. As mentioned previously in this chapter, PGE intends for all resource portfolios, aside from those intentionally designed to rely on the market, to achieve its resource adequacy targets.

10.6 RPS Compliance Strategies

In 2007, Oregon adopted a Renewable Portfolio Standard (RPS) codified under ORS 469A. The Standard adopted with the passage of Senate Bill 838 (SB 838), in 2007, required certain electric utilities to serve at least 25 percent of their retail energy load with RPS-qualifying renewable resources by 2025, with interim targets effective beginning in 2011. In March, 2016, the Governor of Oregon signed into law SB 1547, expanding the RPS requirement for large electric utilities from 25 percent in 2025 to 50 percent in 2040. The percentage of retail energy load met with RPS-qualifying renewable resources increases relative to the prior Standard beginning in 2025. Table 10-4 summarizes the RPS requirements as a percentage of retail load.

TABLE 10-4: Oregon RPS compliance targets (% of retail load)

Compliance Year	SB 838 Compliance %	SB 1547 Compliance %
2020	20%	20%
2025	25%	27%
2030	25%	35%
2035	25%	45%
2040	25%	50%

Qualifying renewable resources include the following, if the resource, or an improvement to the resource, came into operation on or after January 1, 1995:

- Wind
- Solar photovoltaic and solar thermal
- Wave, tidal, and ocean thermal
- Geothermal
- Certain types of biomass
- Biogas from organic sources such as anaerobic digesters and landfill gas
- New hydro facilities not located in federally protected areas or on wild and scenic rivers, and incremental hydro upgrades up to 50 MWa per year from certified low-impact hydroelectric facilities.

Electric utilities can use, subject to certain limitations and independent verification, Renewable Energy Certificates (RECs) to fulfill the RPS requirement. In meeting this requirement, the RPS identifies two classifications of RECs:

1. Bundled, where the energy and REC are sourced from the same generating facility, and
2. Unbundled, where the REC is purchased separately from the underlying power.

In both cases, the qualified resources must be located within the boundary of the Western Electric Coordinating Council (WECC) footprint.

Figure 10-9 and Table 10-4 summarize PGE's expected annual REC generation, relative to RPS obligations through 2040 (with only existing and executed contracts), as of May 2016:

FIGURE 10-9: PGE's projected REC position (2017-2040)

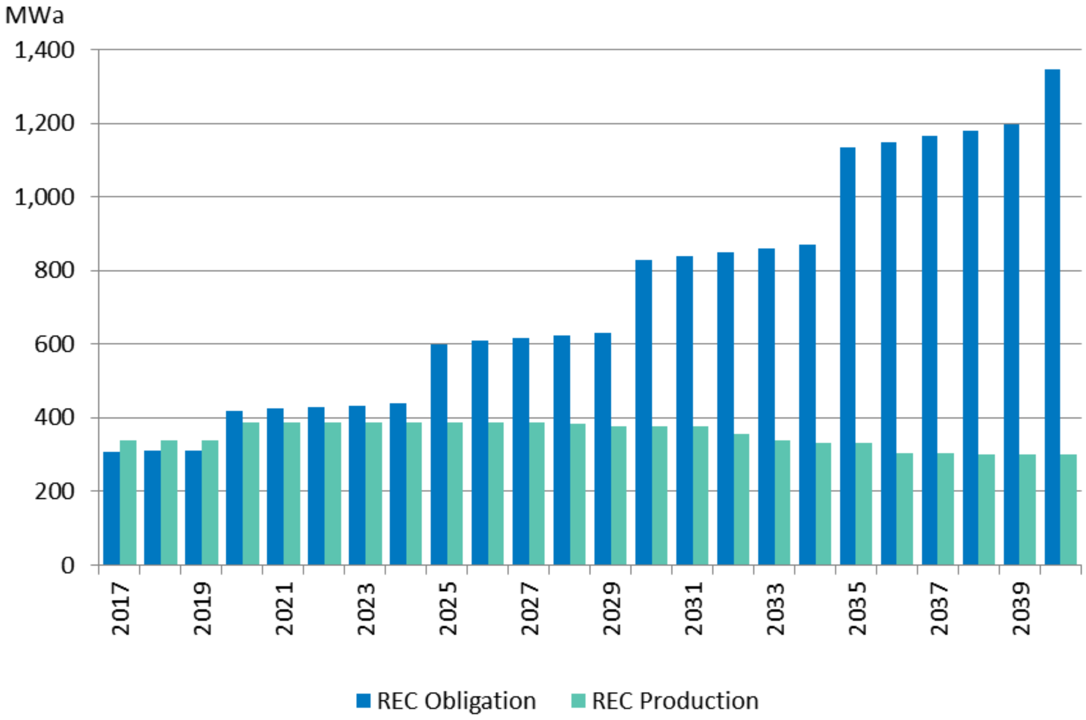

TABLE 10-5: PGE's projected REC obligation and production

	2017	2020	2025	2030	2035	2040
RPS Obligation %	15%	20%	27%	35%	45%	50%
PGE REC Obligation, MWa	309	417	600	828	1135	1347
PGE REC Production, MWa	338	386	387	378	330	302

It is not required, however, that electric utilities meet the annual RPS obligations with an equivalent quantity of qualifying electricity generation on a contemporaneous basis. Rather, Oregon's RPS allows electric utilities to "bank" both bundled and unbundled RECs. The original state RPS legislation allowed for REC banking beginning January 1, 2007, for the purpose of carrying them forward for future compliance. To maintain the integrity of compliance, the Western Renewable Energy Generation Information System (WREGIS) validates the origination of RECs. SB 1547 introduced revisions to the REC banking framework established in SB 838. Importantly, a distinction now exists between RECs that may be banked indefinitely ("infinite life" RECs) and those that can be banked for up to five years from the compliance year in which they are generated. When utilities use RECs from the bank for RPS compliance, the RECs are said to be "retired". Prior to the enactment of SB 1547, Oregon law required RECs to be retired on a first-in, first-out basis (FIFO), with the older RECs being used prior to those generated more recently.

Generally, PGE can meet up to 20 percent of its annual RPS requirement with unbundled RECs.[205] Electric utilities may also elect, or be required by the Commission, to make alternative compliance payments (ACP) to comply with the RPS.

Given the above RPS provisions, PGE must meet at least 80 percent of each annual RPS requirement with some combination of current and banked bundled RECs from qualifying physical resources. The practical effect of the RPS legislation is to promote the acquisition of renewable resources as the primary means of compliance, while allowing for flexibility in implementation to capture market opportunities, avoid short-term cost excursions, and adapt to timing differences in securing new sources of supply.

10.6.1 PGE's REC Position

Oregon established the provisions of the RPS to incent the proliferation of new renewable resources and the achievement of long-run physical compliance. The flexibility provisions in the RPS discussed above (acquisition of unbundled RECs, REC banking, and ACPs) allow utilities to comply with the RPS while minimizing the risk of significant adverse impacts with regard to cost or reliability, but they are not long-term surrogates for renewable generation.

As the Action Plan time horizon in PGE's 2013 IRP did not include a major increase in the RPS target, the acknowledged Action Plan did not include any items associated with Oregon RPS compliance. However, in prior IRPs and IRP Updates, PGE did state that achieving physical compliance with the

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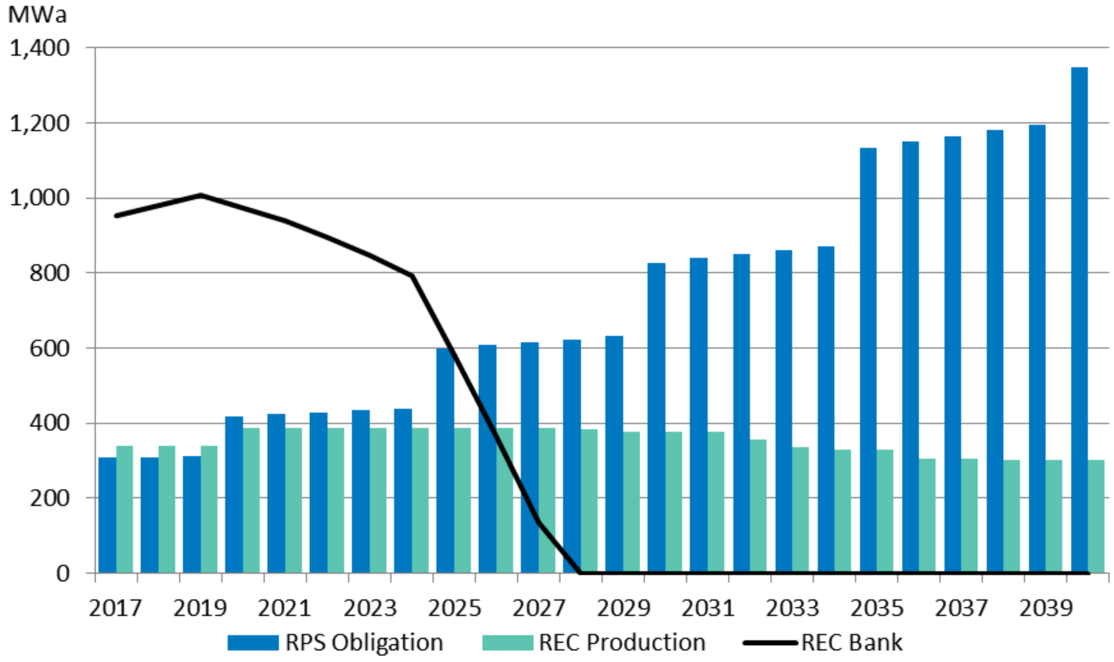
[205] This limitation arises from ORS 469A.145, however, as specified does not apply to renewable energy certificates issued for electricity generated in Oregon by a qualifying facility under ORS 758.505 to 758.555.

RPS provided the best balance of cost and risk for PGE and its customers. PGE established that position in light of the then current circumstances and expectations for future development; specifically during the early years of RPS compliance with rapidly increasing targets and competition to acquire renewable resources.

Beginning with the information presented in Figure 10-9, above, Figure 10-10 overlays PGE's projected REC bank balance assuming the RPS obligations consistent with current law persist throughout the time period, only RECs from existing resources are used for compliance, and the REC bank is drawn from when the annual RPS obligation exceeds the quantity of RECs generated in that year.

FIGURE 10-10: PGE's projected REC bank (2017-2040)



The remainder of this section explores strategies for achieving RPS compliance while taking into consideration the potential benefits and risks associated with relying on the existing REC bank. The discussion below summarizes PGE's current evaluation of its RPS Compliance Strategy.

10.6.2 Options for Achieving RPS Compliance

PGE has five primary options for achieving RPS compliance, subject to certain limitations and cost/risk profiles – acquiring physical energy resources with bundled RECs, purchasing bundled RECs, purchasing unbundled RECs, utilizing banked RECs (that result from previous REC acquisitions – both bundled and unbundled), and alternative compliance payments. PGE may also employ a combination of these strategies, either concurrently or at different points in time. A discussion of each strategy follows:

1. **Physical Compliance.** Utilities can achieve physical compliance either by owning the qualifying resource or by signing long-term PPA with qualifying resources and acquiring the

associated bundled RECs. This strategy attempts to match the long-term RPS liability (obligation) with long-term assets. There is no limitation on the use of bundled RECs for RPS compliance. Bundled RECs created by physical compliance may be banked for future RPS obligations or monetized either infinitely or for up to five years, according to the provisions of SB 1547 discussed above. While utilities can consider both forms of physical compliance long-term, ownership of a qualifying resource provides the opportunity to generate RECs throughout a resource's operating life, plus the potential for residual value (e.g. the option to extend plant life or repower the project) after that time. A long-term PPA will alternately have a finite term, which may be shorter than an equivalent resource's useful life and then require some incremental action at expiration in order to maintain compliance.

2. **Bundled RECs.** In contrast to long-term PPAs with qualifying resources (including the associated RECs), PGE could execute short-term transactions for bundled RECs. Whereas the physical compliance strategy uses long-term assets to meet the long-term RPS liability, short-term assets could also be used to fill a portion of that obligation. Given the need for recurring transactions, this strategy would create additional uncertainty with respect to PGE's RPS compliance position relative to the longer-term options discussed in #1 above.

3. **Unbundled RECs.** RECs purchased separately from the electricity generated by a qualifying renewable resource are "unbundled" RECs. As mentioned previously, the Oregon RPS generally limits the use of unbundled RECs to a maximum of 20 percent of the compliance obligation in each year. This is not a primary strategy for achieving compliance, but instead used to complement a physical or bundled REC compliance strategy.

4. **Previously banked RECs.** A banked REC, in general, is a, "bundled or unbundled renewable energy certificate that is not used by an electric utility or electricity service supplier to comply with a renewable portfolio standard in a calendar year and that is carried forward for the purpose of compliance with a renewable portfolio standard in a subsequent year."[206] Unused RECs accumulate in utilities' banks, and utilities can draw from their banks to comply with future years' RPS obligations. As mentioned previously, utilities may store banked bundled and unbundled RECs either infinitely or for up to five years, according to the provisions of SB 1547. There is no limitation on the amount of banked bundled RECs that utilities may use for compliance. Banked RECs represent a finite source, and, as such, are best suited to providing flexibility and acting as a balancing mechanism to hedge against a number of factors that pose future cost or compliance risks for PGE. These factors are discussed in more detail later in this Chapter.

5. **Alternative Compliance Payments (ACP).** Oregon legislation provides for the use of alternative compliance payments in lieu of acquiring bundled or unbundled RECs for meeting RPS obligations.[207] However, the legislature did not intend for utilities to use the ACP provision as a strategy for achieving RPS compliance over time. ORS 469A supports this interpretation, as it directs the Commission to, "set the rate to provide adequate incentive for the electric company or electricity service supplier to purchase or generate qualifying

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[206] ORS 469A.005(1).

[207] ORS 469.180.

electricity in lieu of using alternative compliance payments to meet the renewable portfolio standard."[208] The OPUC, at the July 21, 2015, Public Meeting, set the alternative minimum compliance payment at $110 per MWh for the years 2015 and 2016. This is the cost that a utility will incur for any REC deficits in those compliance years. Additionally, ORS 469A allows the Commission discretion in rate recovery of ACPs and use of such funds.

10.6.3 Renewable Energy Certificates

As discussed above, the RPS limits the use of unbundled RECs to a maximum of 20 percent of the compliance obligation in each year. Unbundled RECs, by definition, do not have an energy component. If a utility pursues an unbundled REC strategy and their expected energy needs exceed the expected RPS compliance obligation, they must account for the energy deficit component associated with the unbundled RECs. In the long-run, the fundamental market price of unbundled RECs should not exceed the difference between the expected levelized cost of energy from an incremental qualifying resource and the levelized cost of energy from the marginal non-qualifying alternative. In reality, a number of additional factors may influence the market price of unbundled RECs over the short-term, including (but not limited to): the geographic location of the generator, the underlying technology, the vintage of the REC, and factors affecting demand (compliance targets, economic/load growth, energy efficiency, and potentially voluntary markets). These factors generally describe whether the REC can be used for compliance in a given market. If it is expected that unbundled RECs will be available in the market for less than the price of bundled RECs (when comparing on an energy-, and capacity-equivalent basis), using up to the maximum amount of unbundled RECs could reduce RPS compliance costs in the short-term.

However, the absence of an organized market enabling efficient pricing of RECs makes it difficult to propose a long-term strategy predicated on unbundled RECs. Further, PGE's experience indicates that short-term supply and demand mismatches can have large influences on the pricing of unbundled RECs. Constantly changing market dynamics make it unlikely that recent imbalances will persist in the long-run. Rather than assuming the availability of unbundled RECs, these factors persuade PGE to consider further actions prior to determining the extent to which unbundled RECs should play a role in the long-run RPS compliance strategy. One such factor is the supply curve of unbundled RECs available in the market.

Additionally, as mentioned above, the energy deficit component associated with the unbundled RECs must be accounted for when considering the potential for their use in a long-term RPS compliance strategy. Beyond 2021, PGE projects that incremental annual average energy needs will exceed the incremental annual RPS requirements. As a result, two options emerge for PGE to achieve RPS compliance:

1. Rely entirely on bundled RECs (existing and incremental) to meet RPS compliance.
2. Acquire bundled RECs to meet at least 80 percent of the RPS requirement and acquire a combination of non-qualifying electricity and unbundled RECs (up to the current 20 percent annual limit) to meet the remaining need.

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[208] Id. (2).

In order for the second strategy (acquisition of unbundled RECs in lieu of bundled RECs) to be cost-effective, it should meet two economic tests:

1. The expected life-cycle levelized cost for qualifying resources is greater than the capacity equivalent cost for non-qualifying alternatives at the time of the decision.
2. The cost of unbundled RECs is less than the cost difference between the qualifying resource and the non-qualifying alternative identified in 1 above.

A simple example can be devised to provide insight into the potential cost impacts of a strategy with no unbundled REC purchases relative to a strategy relying on unbundled RECs for up to 20 percent of the annual obligation. Three scenarios can be considered, reflecting various relationships between unbundled REC prices and the hypothetical cost premium for RPS renewables (on a levelized cost of energy basis versus a non-renewable alternative):

1. Unbundled REC prices are equal to the hypothetical cost premium for RPS renewables
2. Unbundled RECs prices are less than the hypothetical cost premium for RPS renewables
3. Unbundled REC price are more than the hypothetical cost premium for RPS renewables

In reality, if the hypothetical cost premium for RPS renewables represents the intrinsic value of a bundled REC, it is not reasonable to expect an entity to willingly pay more than this amount for an unbundled REC on a long-term basis. However, the presence of a regulatory mandate or some other market constraint could result in inefficient pricing of the two products. An entity relying on short-term markets to acquire RECs could encounter a supply-shortage with respect to bundled RECs, jeopardizing their ability to meet their compliance obligation. Under such a situation, the price of any unbundled RECs available for compliance would approach the effective cap imposed by the ACP cost. Although scenario 3 serves as a reminder of the potential costs of bad outcomes, it is not realistic to consider on a long-term basis.

TABLE 10-6: Illustrative unbundled REC price scenario

Assumptions			
"Typical" New Resource Annual Supply	**100**	**MWa**	**[1]**
Resource Life	**27**	**Years**	**[2]**
Levelized Cost of Non-Qualifying Resource	**$74**	**per MWh**	**[3]**
Premium % for Qualifying Resources	**10%**		**[4]**
Premium for Qualifying Resource	**$7.40**	**per MWh**	**[5] = [3] x [4]**
Implied Cost for Bundled RECs	**$7.40**	**per REC**	**[6] = [5]**
Annual RECs Generated from Qualifying Resource	**876,000**		**[7] = [1] x 8760**
Cost Comparison of Hypothetical Cases			
Case A: Unbundled RECs price = Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$7.40		[8] = [6]
Fill 80% with Bundled RECs (000s)	$5,186		[9] = [7] x 0.8 x [6]
Fill 20% with Unbundled RECs (000s)	$1,296		[10] = [7] x 0.2 x [8]
Total cost for RECs (000s)	**$6,482**		[11] = [9] + [10]
Total Levelized Resource Cost, with RECs (000s)	$71,306		[12] = [7] x [3] + [11]
Case B: Unbundled RECs price 50% of Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$3.70		[13] = [6] x 0.5
Fill 80% with Bundled RECs (000s)	$5,186		[14] = [7] x 0.8 x [6]
Fill 20% with Unbundled RECs (000s)	$648		[15] = [7] x 0.2 x [13]
Total cost for RECs (000s)	**$5,834**		[16] = [13] + [14]
Cost: B cost for RECs less A cost for RECs	$(648)		[18] = [17] / [11]
Cost: B over A (%)	-10.0%		[17] = [16] – [11]
Cost impact to Total Resource Cost	**-0.9%**		[19] = [17] / [12]

This illustrative example presents a potential levelized-cost effect. Implicit within the scenario is an assumption that the use of unbundled RECs allows for the deferral of bundled REC actions in a manner that allows for effective management of the REC bank. Consistent with PGE's recent RPS Implementation Plan filings with the OPUC, the above example demonstrates that if unbundled RECs are available at a significant discount to bundled RECs, the potential reduction in the cost of RPS compliance could be significant. However, as stated above, PGE regards the quantity and price of available unbundled RECs as highly uncertain.

As mentioned previously, PGE's portfolio analysis in this IRP includes portfolios designed to assess the potential effects, on an NPVRR basis, of relying on the REC bank and acquiring sufficient unbundled RECs to meet 20 percent of PGE RPS compliance obligation over a period of time. The results of those analyses are presented in Chapter 12, Modeling Results.

10.6.4 Considerations for REC Bank Management

The banking provisions of the Oregon RPS provide an important flexibility mechanism for electric utilities. The RPS provisions allowed for the banking of RECs from qualified resources starting in 2007, four years prior to the first compliance year of 2011. Although SB 1547 modified the REC banking provisions, these banked RECs may act as a balancing mechanism to hedge against a number of factors that pose future cost or compliance risks for PGE. Earlier in this chapter, PGE discussed a number of factors and indicators that require consideration when evaluating potential strategies for achieving RPS compliance (future changes in environmental policy, resource availability, technological innovations, etc.). PGE examines six general roles the REC bank may potentially play:

1. **Mitigating timing differences in acquiring and constructing new renewable generation.** As discussed previously in this IRP, changes in national environmental policy may have a significant impact to the future cost and availability of both renewable and non-renewable resources. While PGE does not expect any potential resource requirements arising from the CPP in this IRP, other emissions constraints and costs (such as a state-, regional-, or national-level CO_2 tax) could be impactful in the future. Where incremental RPS obligations do exist, maintaining a REC bank balance allows PGE the flexibility to adjust the timing of that resource action.
2. **Acting as a temporary alternative to physical supply in the event of adverse market conditions (e.g., an RFP results in unsatisfactory RPS resource options).** Increased demand for renewable resources in the future may result in competition or reduced availability of quality renewable resource sites. Unless these factors are offset by other developments, such as technological improvements, these factors could result in higher costs and reduced efficiency for renewable resources in the future. An RFP process would likely reflect these results. If that were to be the case, a REC bank balance of sufficient size provides PGE the option to defer resource selection and re-run an RFP with the goal of achieving a better result for customers.
3. **Replacing RECs from physical resources generating at levels less than forecast (e.g., below forecast wind year).** PGE's current RPS resource portfolio is predominantly composed of wind resources. Developing a long run RPS compliance strategy relies on a forecast of the generation from these resources. The actual amount of wind generation is inherently uncertain and will likely exceed or fall short of the forecast in each RPS compliance period.

4. **Aligning timing differences in acquiring and constructing new renewable generation with tax policy.** As discussed in Chapter 3, Planning Environment, and earlier in this chapter, PGE believes that federal subsidies to the renewable energy sector will eventually sunset based on current law. The PTC is expected to phase-out on its current glide path, and the ITC will phasedown to 10 percent on the trajectory presently defined in law. Changes in tax credit availability are a factor potentially driving the RPS compliance strategy in this IRP. The benefits of additional flexibility with regard to the timing of resource actions discussed in factor 1 above apply here as well.
5. **Providing a temporary means of compliance with increased RPS targets (beyond those currently enacted).** While the REC bank would be a valuable tool for maintaining RPS compliance in a situation with increasing obligations, PGE does not expect further increases to Oregon's recently-enacted RPS requirements. The discussion of those recent increases pursuant to SB 1547 is provided above in this Chapter, as well as in Chapter 3, Planning Environment.
6. **Filling the incremental RPS compliance obligation resulting from retail load growing more quickly than forecast.** Similar to the reliance on a long-term generation forecast for RPS resources as discussed above in factor #3, as PGE's annual RPS obligations are a function of retail load, an RPS compliance strategy also relies on a long-run load forecast. The amount of load that will actually materialize will either exceed or fall short of the forecast in each RPS compliance period. The ability to draw from the existing REC bank allows PGE to maintain RPS compliance during times of relatively high load growth.

Table 10-7 quantifies the scenarios which approximate the potential magnitude for these risk factors, given PGE's current resource portfolio and the current Oregon RPS targets. Table 10-7 also groups these risk factors into three general categories:

Deferral Risk

Risks related to in-service dates for future RPS resources (factors #1, #2, and #4 above) are represented by a need for banked RECs sufficient to cover the incremental RECs associated with that resource for between one and two years. The amounts for the "2025-2029" and future time periods assume that compliance was achieved for the prior periods (i.e., they reflect the incremental need for that period). It is also possible that an RFP resulting in sub-par bids could create a delay of more than one year.

Forecast Generation Risk

To assess the risk of under-generation relative to forecast (factor #3), PGE assumes RPS resources under-generate by approximately 22 percent (approximately the largest consecutive 12-month difference between actual and forecast generation wind experienced by PGE to-date). This 22 percent under-forecast generation is applied to existing wind and assumes that a wind resource is used to achieve RPS compliance in each period.

As discussed above, PGE does not currently expect for further increases to the state RPS beyond those currently enacted (factor #5). Thus, no further consideration is given to factor #5 in this analysis.

Load Forecast Risk

Finally, to assess the REC demands associated with a High Load Growth future for one year relative to the base forecast (factor #6), PGE relied on the difference in the year-over-year growth rates of PGE's Reference Case and High Load Growth futures. Table 10-7 below summarizes the results of these sensitivities to provide context to the potential risks posed by depleting the REC bank. The "worst year", given these exposures, adjusts the "total exposure" to account for the mutual exclusivity of a resource being both the subject of an in-service date delay and under-generation relative to forecast. This adjustment applies a one-period lag to the under generation effect.

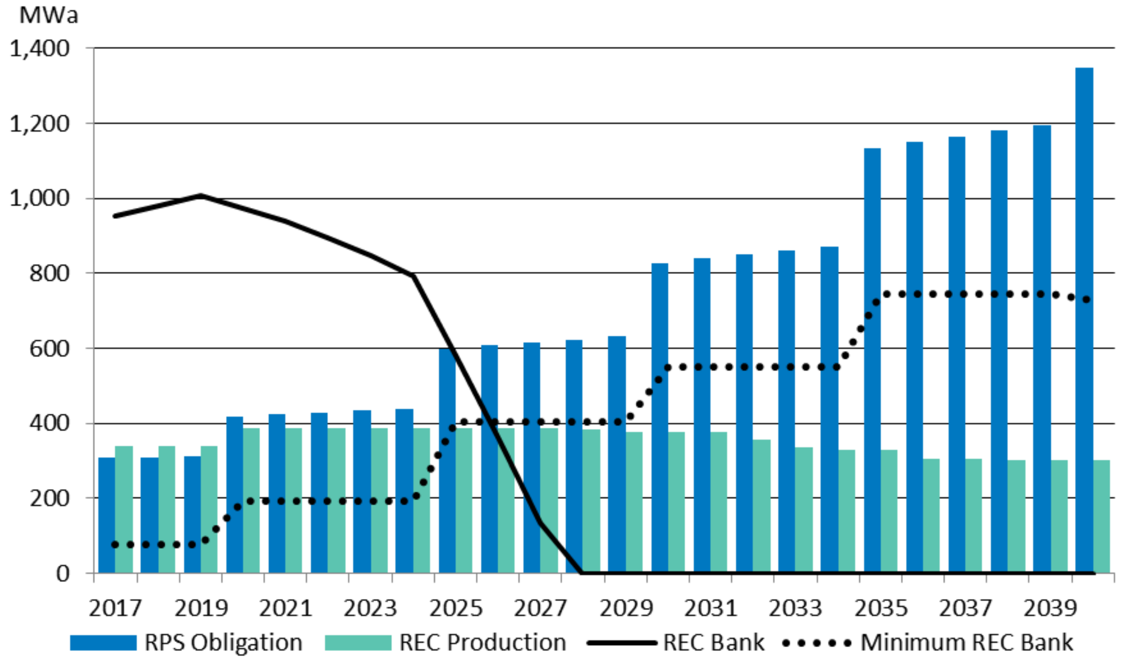
TABLE 10-7: REC bank risk factor scenario

	2015-2019	2020-2024	2025-2029	2030-2034	2035-2039	2040
Annual RPS Deferral Risk	0	69	183	236	307	237
Annual Forecast Generation Risk	51	74	114	163	230	276
Annual Load Forecast Risk	0	10	13	16	27	19
One-Year Adjusted REC Risk	**51**	**130**	**271**	**366**	**497**	**486**
Two-Year Adjusted REC Risk	**102**	**259**	**541**	**732**	**994**	**973**

As the existing REC bank is finite in nature, a strategy that relies on drawing down the current bank is not a viable long-run means for meeting RPS obligations. However, the REC bank does represent a valuable tool for ensuring flexibility in implementing PGE's RPS strategy over time. The factors discussed above lead PGE to plan for maintaining a minimum REC balance sufficient to cover one- to two-years' worth of event risks over the 2020-2024 planning horizon, or approximately 130–260 MWa. For planning purposes, PGE uses the mid-point of the one- to two-year range for each time period.

This mid-point of the minimum REC bank balance range is added to the information previously presented in Figure 10-10 in order to give a more complete picture of PGE's projected forward REC bank position relative to the minimum recommended level as indicated in Figure 10-11.

FIGURE 10-11: REC bank position with minimum REC bank



Based on the results above, PGE concludes that, in order to determine the current least-cost, least-risk approach for compliance with the long-term RPS requirement established by SB 1547, the best course of action is to conduct a market solicitation for bundled and unbundled REC products in order to assess their relative availability and price. From that point a recommendation will be made to pursue a specific RPS compliance and associated REC procurement strategy. If a bundled REC strategy is recommended, further analysis will provide a determination as to whether the most cost-effective set of resource actions is time sensitive as it relates to reliance on the PTC. This approach enables PGE to assess the viability and cost-effectiveness of a strategy potentially relying on unbundled RECs up to the maximum quantity either allowed or available. PGE continues to advocate for using the REC bank as a balancing mechanism to hedge against factors that pose future cost or compliance risks for PGE. As such, the REC bank will be managed within reasonable bounds, as established below, to provide a sufficient quantity of RECs to insulate customers from potentially costly compliance risks in the future.

The assumption in most resource portfolios is for an RPS compliance strategy that begins with 175 MWa of incremental long-term qualifying resources in 2018. The timing of this strategy seeks to take advantage of the full PTC value available to eligible resources that satisfy safe harbor constraints by year-end 2016 and comply with the assumed construction period duration. Additional RPS compliance strategies are also tested, as described in further detail below. Amongst those strategies, several constants are present: portfolios achieve physical RPS compliance by 2025; beyond 2025, differences in early RPS resource action either allow for deferral or acceleration of long-term resource acquisition. The RPS compliance strategy included in the resource portfolios considered in this IRP builds on the concepts outlined above.

CHAPTER 11. Scoring Metrics

This chapter presents the scoring methodology PGE used to evaluate the candidate portfolios for the Action Plan.[209] The Company applied several metrics to score and rank the portfolios and the relative performance of each portfolio guided the development of PGE's Action Plan.

Chapter Highlights

- ★ **PGE developed scoring metrics with input from stakeholders to identify portfolios that represent the best combinations of cost and risk.**
- ★ **Scoring metrics in the 2016 IRP are largely aligned with the metrics presented in the 2013 IRP.**
- ★ **PGE applied weights to the quantitative metrics in order to rank the portfolios: 50 percent to the cost metric and 50 percent to the combined risk metrics.**

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[209] See Chapter 10, Modeling Methodology, for more information on the portfolios and Chapter 12, Modeling Results, for discussion of the portfolios that are candidates for the Action Plan; see also, Appendix O, Portfolio Detail.

11.1 OPUC Guidelines

OPUC IRP guidelines govern PGE's approach in evaluating portfolio costs and associated risks:

Guideline 1c

- "The primary goal must be the selection of a portfolio with the best combination of expected costs and associated risks."
- [...] "Utilities should use PVRR as the key cost metric"
- [...] "To address risk, the plan should include, at a minimum two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes."

Guideline 11

"Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios."

11.2 Scoring Methodology

PGE used the above guidelines and input from stakeholders over the course of multiple IRP cycles to develop scoring metrics for the evaluation of candidate portfolios for the Action Plan. In total, PGE evaluated and scored portfolios based on four metrics: cost, variability, severity, and durability across futures. These metrics are each discussed below.

Cost		
1. Net Present Value of Revenue Requirement (NPVRR)		
Risk		
2. Variability	3. Severity	4. Durability Across Futures

11.2.1 Cost

As required by the Commission IRP Guideline 1c, the key metric to assess cost is the net present value of revenue requirement (NPVRR) of each portfolio in the Reference Case in 2016 dollars. The Reference Case represents the expected case of the individual input assumptions (fuel prices, load forecast, CO2 prices, resource costs, resource availability, etc.), under which PGE analyzed the portfolios. For each portfolio, the NPVRR includes the fixed and variable costs associated with owning (capital) and operating (fixed operating and maintenance, variable operating and maintenance, fuel, and emissions) the respective resources, as well as the net market revenue or expense (of net sales or purchase). The methodology for calculating these costs is presented in Chapter 10, Modeling Methodology. PGE applies a 50 percent weight to the cost metric in portfolio scoring in order to equally balance cost and risk metrics.

11.2.2 Risk

PGE assessed the risk associated with the expected economic performance of each portfolio by completing an extensive scenario analysis. Each scenario consisted of an Action Plan candidate portfolio under operation within one of 23 identified potential futures, resulting in 22 potential NPVRRs for each portfolio in addition to the Reference Case NPVRR. The futures, which are discussed in Chapter 10, Modeling Methodology, explore uncertainties in key variables like fuel prices, CO_2 prices, load growth, capital costs, and resource availability. The goal of the scenario analysis was to identify the portfolios that consistently perform well across these futures, or in the case that relative portfolio performance is sensitive to uncertain future conditions, identify the relative risks of each portfolio with respect to variability and severity through a risk scoring process. PGE went through a lengthy public process in the current and prior IRPs to identify metrics that incorporate these risk considerations. These were most recently discussed in the August 17, 2016 IRP Roundtable Meeting #16-3. While the 2016 IRP made use of the same three risk metrics employed in the 2013 IRP, some adjustments were made to the calculation of the metrics to improve alignment with OPUC Guideline 1c. The three risk metrics include:

1. **Variability;**
2. **Severity;**
3. **Durability across futures.**

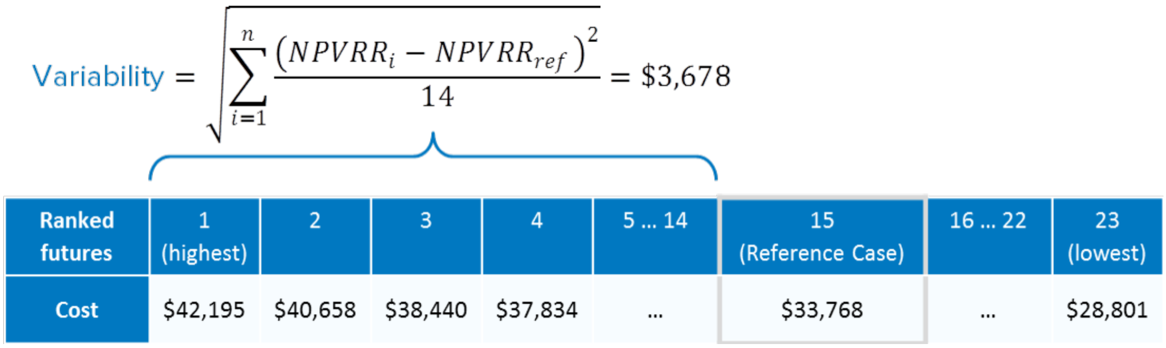
The combined risk metrics received a score weight of 50 percent of the portfolio total score allocated evenly across metrics 1, 2, and 3, resulting in a 16.7 percent weight to each.

Variability

In the 2013 IRP, PGE measured the variability of each portfolio as the average NPVRR across the four worst futures (i.e., the futures in which the portfolio cost is the greatest), less the NPVRR of the portfolio in the Reference Case. For the 2016 IRP, the calculation of this metric was updated to incorporate variability across a larger number of futures and to reduce the relative impact of the highest cost futures because they are incorporated into the severity metric. PGE calculated the updated variability metric as the semivariance of the NPVRR across the futures for which the NPVRR exceeded the Reference Case NPVRR:

$$\text{Variability} = \sqrt{\sum_{i=1}^{n} \frac{\left(NPVRR_i - NPVRR_{ref}\right)^2}{n}}$$

Where $NPVRR_i$ is the cost associated with future *i*, $NPVRR_{ref}$ is the cost in the Reference Case, and *n* is the number of cost outcomes that are higher than the cost in the Reference Case. Below is an example to illustrate the variability metric for the *Wind in 2018 + High EE* portfolio.



$$\text{Variability} = \sqrt{\sum_{i=1}^{n} \frac{\left(NPVRR_i - NPVRR_{ref}\right)^2}{14}} = \$3{,}678$$

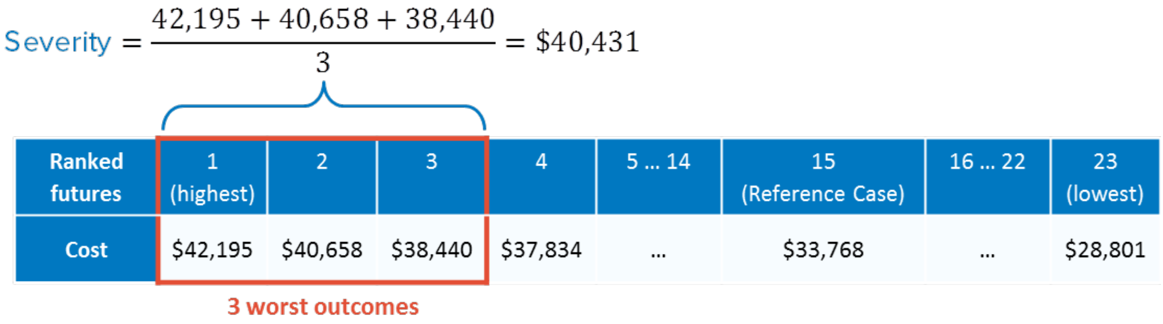
Ranked futures	1 (highest)	2	3	4	5 ... 14	15 (Reference Case)	16 ... 22	23 (lowest)
Cost	$42,195	$40,658	$38,440	$37,834	...	$33,768	...	$28,801

This metric gives PGE an indication of how much the cost of a given portfolio may vary above the Reference Case cost – or how sensitive a given future is to uncertain conditions. This is primarily a measure of certainty. The semivariance was employed rather than a measure of variability across both high and low cost outcomes due to the asymmetrical impact that higher than expected electricity costs have on customers relative to lower than expected costs. PGE received feedback from stakeholders that this revised variability metric may still place too much emphasis on high cost outcomes. In response, PGE incorporated a supplemental analysis of costs and risks that considered both high and low cost outcomes in a single risk metric – this can be found in Appendix L, Supplemental Findings Across Futures.

Severity

The severity metric, which PGE also incorporated into the 2013 IRP, focuses on the absolute magnitude of bad outcomes. PGE calculated this metric, in both the 2013 IRP and the 2016 IRP, as the absolute average NPVRR across the futures that approximately fall in the top 10th percentile with respect to cost. In the 2016 IRP, the Company selected the three most expensive futures for inclusion in the severity metric.

As an example, Portfolio 13, *Wind in 2018 + High EE*, cost for each of the 23 futures is as shown below. There are 23 cost outputs sorted in decreasing order; the severity risk of the portfolio is the average of the three worst outcomes.



$$\text{Severity} = \frac{42{,}195 + 40{,}658 + 38{,}440}{3} = \$40{,}431$$

Ranked futures	1 (highest)	2	3	4	5 ... 14	15 (Reference Case)	16 ... 22	23 (lowest)
Cost	$42,195	$40,658	$38,440	$37,834	...	$33,768	...	$28,801

3 worst outcomes

While the variability measures the dispersion relative to the Reference Case and differentiates portfolios that are sensitive to uncertain future conditions, the severity metric differentiates portfolios that introduce a risk of especially bad outcomes that may put undue stress on customers. PGE received feedback that because portfolios with high Reference Case costs also tended to have the higher costs under bad outcomes, the severity metric may be placing too much emphasis on cost. In response, the supplemental analysis described in Appendix L, Supplemental Findings Across Futures, contemplates a cost/risk framework that excludes the severity metric.

Durability across futures

For the third risk metric, PGE examined the durability of each portfolio's performance across futures. Consistent with the methodology employed in the 2013 IRP, the calculation of durability is performed by examining the frequency with which each portfolio ranked among the top-third (lowest cost) or bottom-third (highest cost) of all portfolios for a given future. PGE performed this ranking for each future. The formula is:

$$P[\text{good performance}] = \frac{[\text{number of futures in which portfolio is among the top third of portfolios}]}{[\text{total number of futures}]} \times 100$$

$$P[\text{bad performance}] = \frac{[\text{number of futures in which portfolio is among the bottom third of portfolios}]}{[\text{total number of futures}]} \times 100$$

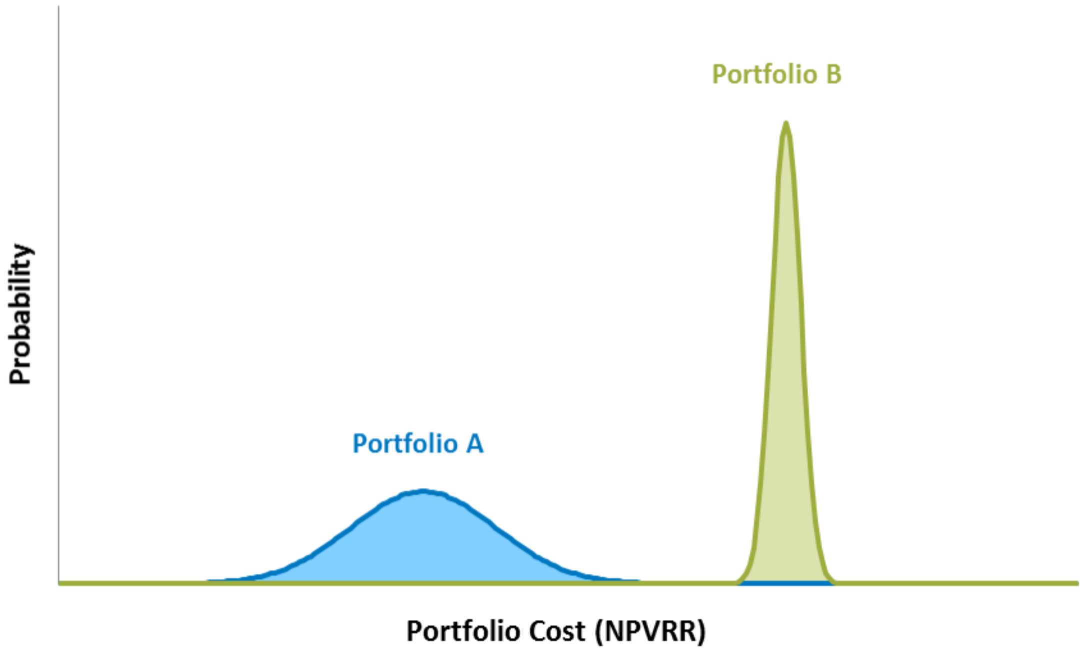
$$\text{Durability across futures} = P[\text{good performance}] - P[\text{bad performance}]$$

PGE expresses durability across futures as a percentage that can be positive, negative, or zero.

Unlike the cost, severity, and variability metrics, which look at one portfolio and compare its different cost outcomes across all futures, the durability across futures metric is a comparison between the costs of all portfolios for one future at a time. PGE interprets the durability across futures of a portfolio as the likelihood that it would perform well under the different probable futures versus the likelihood it would perform badly.

The durability metric is helpful when considering two portfolios that may perform quite differently with respect to cost and risk but could have similar total portfolio scores due to the weights applied to cost and risk metrics. An illustrative example is shown in Figure 11-1. In this example, Portfolio A has low cost but high risk due to high variability and Portfolio B has high cost but low risk. Depending on the relative weighting of cost and risk metrics, either portfolio is capable of being interpreted as the best performing portfolio. However, Portfolio A is lower cost than Portfolio B in every possible future – or, regardless of how conditions evolve, customers would always prefer Portfolio A in hindsight. Consideration of this type of ordinal information within futures is critical to effective application of scenario analysis in decision making and this is achieved in the IRP through the durability metric.

FIGURE 11-1: Illustrative cost distributions for two competing portfolios



11.3 Reliability

RECAP is a stochastic model developed by Energy + Environmental Economics (E3) to calculate reliability metrics, such as:

- Loss of Load Expectation (LOLE)
- Loss of Load Probability (LOLP)
- Expected Unserved Energy (EUE)
- Effective Load Carrying Capability (ELCC) of VERs; and
- Capacity shortage associated with a given reliability standard

PGE generally designed all of its portfolios (except the *RPS Wind 2018 + No Capacity Action*) to meet a one-day-in-10-years (or 2.4 hours per year) loss of load expectation (LOLE) reliability standard. For each portfolio, the Company utilized the Renewable Energy Capacity (RECAP) model discussed in Chapter 5, Resource Adequacy, to identify the incremental capacity required to meet the reliability standard after accounting for the RPS and technology-specific resource actions under investigation. For all portfolios with the exception of the *RPS Wind 2018 + No Capacity Action* portfolio, PGE then added sufficient generic capacity resources to meet the identified need.[210] Reliability metrics, including LOLE, expected unserved energy (EUE), and the expected unmet demand in the worst 10th percentile of loss of load events (TailVar90), are summarized for each portfolio in Appendix O, Portfolio Detail.

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[210] See Chapter 10, Modeling Methodology, for more information.

11.4 Scores and Weights

In this section, PGE explains how it compiles the above-described metrics into a portfolio score, which the Company uses to rank the portfolios and determine the top performers.

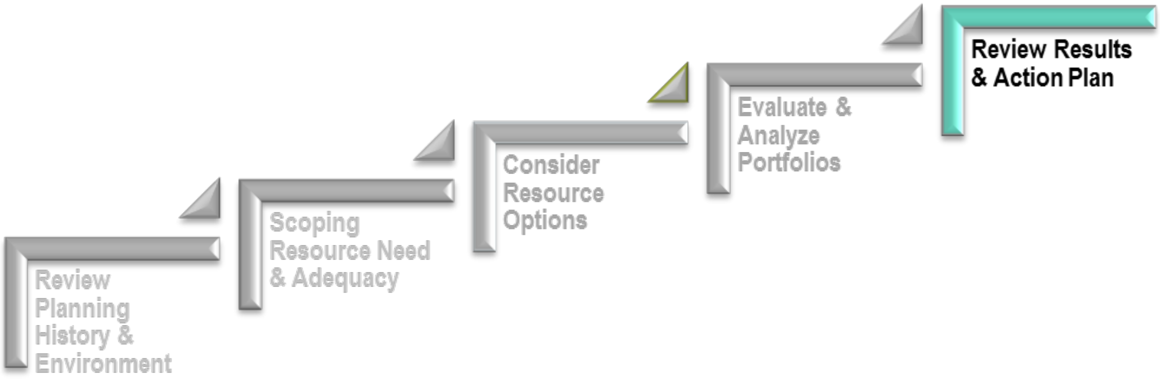
1. PGE screens portfolios that do not achieve the reliability target (*RPS Wind 2018 + No Capacity Action*) and those that were included for the purpose of testing or analyzing a particular issue, but would not be "actionable" within the scope of this IRP. Specifically, in addition to those portfolios not achieving the reliability target, PGE screened the following two types of portfolios: portfolios analyzed for the sole purpose of addressing a specific issue; and portfolios that resulted in resource actions outside the Company's action plan horizon. Table O-1 in Appendix O, Portfolio Detail, lists all portfolios evaluated in the scenario analysis and indicates the purpose of each and whether or not it was considered as an action plan candidate. This does not eliminate resources within screened portfolios from participating in future resource acquisition processes.
2. PGE subjects remaining portfolios to cost and risk scoring. In order to determine the relative "value" of each portfolio, PGE assigns a score based on relative portfolio output's position with respect to the best output for each metric. For example, the portfolio with the lowest reference case cost gets the "cost" score of 100 and the portfolio with the highest cost gets a score of zero. PGE then scales the scores for the remaining portfolios based on their relationship to the best and worst performers in a particular metric.
3. PGE applies a weight for each of the scores, based on a 50/50 split between cost and risk metrics, as follows:

	Cost Metric	Risk Metric		
	Reference Cost	Variability	Severity	Durability across futures
Weight	50%	16.7%	16.7%	16.7%

4. PGE adds the weighted scores for all metrics to come up with the total portfolio score. PGE then ranks the portfolios based on the total portfolio scores. The Preferred Portfolio is the one which results in the highest total score. Please refer to Appendix O, Portfolio Detail, for a description of the various portfolios PGE contemplated in this IRP, and Chapter 12, Modeling Results, for the scoring results and the Preferred Portfolio.

In the 2016 IRP, PGE was encouraged by the interest on the part of stakeholders in the portfolio scoring methodology. The Company balanced feedback from stakeholders in the 2016 IRP cycle with the considerable effort on the part of PGE and stakeholders in prior IRP cycles to develop metrics that appropriately capture various impacts of resource planning decisions on customers. In addition, PGE provided a supplemental cost/risk analysis in Appendix L, Supplemental Findings Across Futures, to provide additional insights into the relative performance of the Action Plan candidate portfolios across alternative measures of cost and risk. In future cycles, PGE looks forward to further engaging with stakeholders and industry experts on the design of scoring metrics that address the needs of customers and are analytically appropriate to PGE's scenario analysis framework.

Part V. Results and Action Plan



CHAPTER 12. Modeling Results

The following chapter presents the results of PGE's portfolio analysis and modeling, as well as PGE's conclusions regarding the cost and risk results. As discussed in Chapter 10, Modeling Methodology, regarding PGE's analytical approach, models do not provide incontrovertible answers to questions regarding future resource needs and strategies for meeting those needs; they provide estimates of future performance for various alternatives, or a range of potential results, given a set of assumptions. PGE's IRP portfolio analysis provides important insights and guidance to the strategic decision-making process, resulting in a selection of resources more likely to perform well under a variety of conditions. The results described in this chapter do not provide a single, clear-cut answer as to which combination of potential resources provides the optimal balance of cost and risk. Rather, the relative performance of various resource alternatives can differ widely depending upon varying future circumstances. Accordingly, PGE's objective is to identify a robust portfolio that performs better than other alternatives under a wide range of potential future circumstances.

Chapter Highlights

- ★ **The broad range of portfolios evaluates key performance drivers, including resource technology, diversity, quantity, and timing across multiple futures.**
- ★ **All of PGE's actionable portfolios have sufficient resource capacity to meet reliability obligations.**
- ★ **Early action with respect to RPS, which captures relatively more of the available production tax credits (PTC) prior to phase-out, is preferable to deferring action.**
- ★ **The Preferred Portfolio – *Efficient Capacity 2021* – procures renewables to meet RPS targets, an efficient combined cycle combustion turbine (CCCT) in 2021, and fills the remaining capacity need with generic capacity resources.**

12.1 Portfolio Analysis

The three key risk factors driving the structure of the futures for this IRP, as identified in Chapter 10, Modeling Methodology, are:

1. Potential costs of CO_2 emissions;
2. Natural gas prices; and
3. Portfolio load.

Analytical results and observations regarding the effects on portfolio performance of each of these risk factors, over the range of potential futures, are set forth below. PGE further refines these analytical results through the application of the scoring metrics discussed in Chapter 11, Scoring Metrics. To assess the performance of each candidate resource portfolio, PGE considers two main factors:

1. Portfolio cost under Reference Case conditions (net present value of revenue requirements or "NPVRR"). As discussed in Chapter 10, Modeling Methodology, and Chapter 11, Scoring Metrics, the NPVRR includes the fixed and variable costs associated with owning and operating the respective resources, as well as the net market revenue or expense associated with net sales or purchases in the portfolio; and,
2. Each portfolio's exposure to economic risk using three views of risk: severity, variability, and durability across futures.

Applying the scoring metrics enables the selection of a Preferred Portfolio.

12.2 Overview of Portfolio Analysis Results

A box-and-whisker plot provides a convenient means to visually assess the distribution of scenario results in terms of NPVRR (vertical axis). The box-and-whisker plot in Figure 12-1 provides an illustration of how PGE translates the scenario results into the plot, in this case using the results for the *Efficient Capacity 2021* portfolio. For this illustration, PGE plots the NPVRR for this portfolio, resulting from each of the 23 futures, from highest cost (the future representing the worst outcome) to lowest cost (the future representing the best outcome). The upper- and lower-ends of the vertical line, or "whiskers," represent the highest and lowest cost outcomes, respectively, for the portfolio. PGE draws a box around the middle 50 percent of outcomes, or interquartile range, which gives an indication of the dispersion of results. The cost under the Reference Case is indicated by the black "X" and the median cost is shown by the grey horizontal line dividing the box into the middle quartiles. In addition, the averages of the three worst and three best outcomes are indicated by the red and blue diamond, respectively. Please refer to Chapter 10, Modeling Methodology, or Appendix O, Portfolio Detail, for a detailed description of each portfolio. For additional discussion and detail regarding the performance of portfolios across futures, please also refer to Appendix L, Supplemental Findings Across Futures.

FIGURE 12-1: Guide to box-and-whisker plots

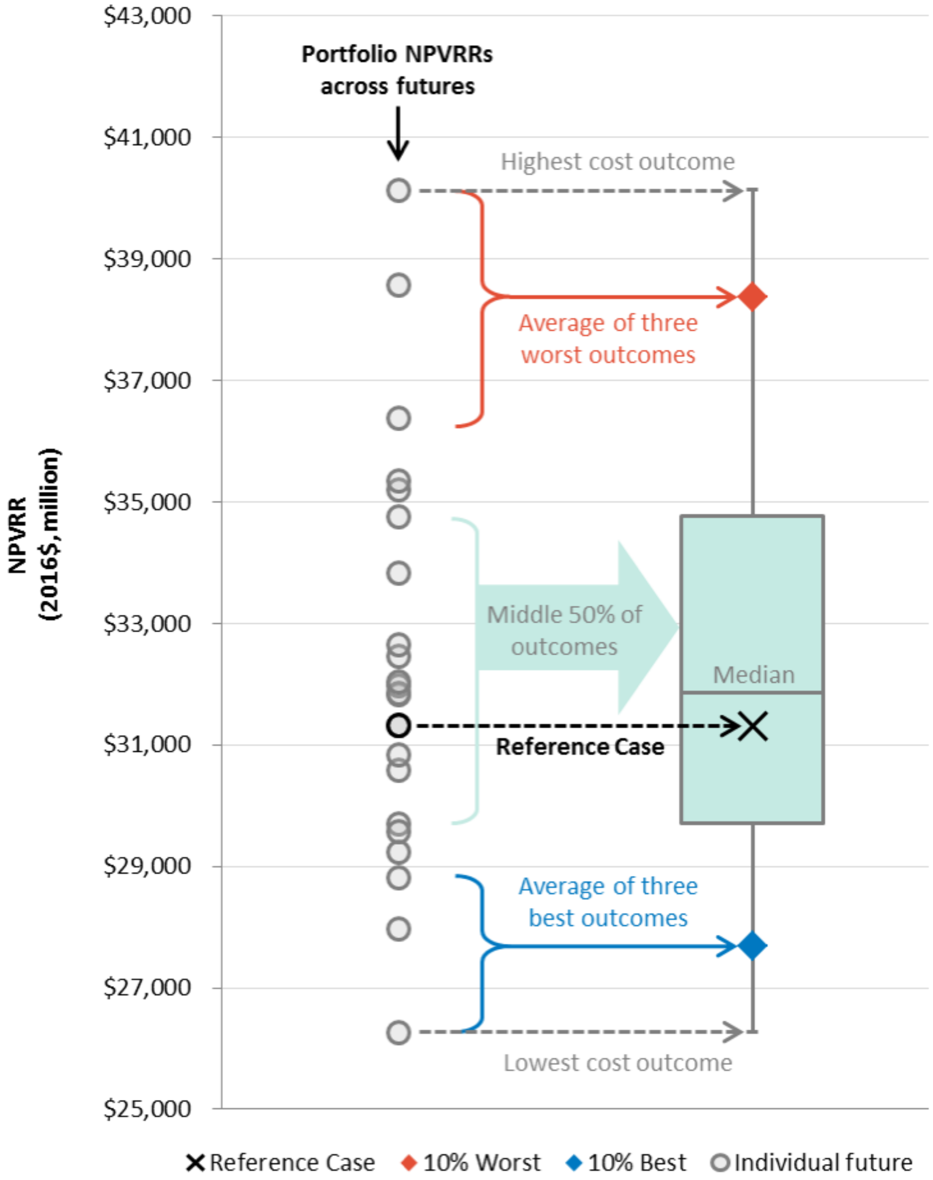
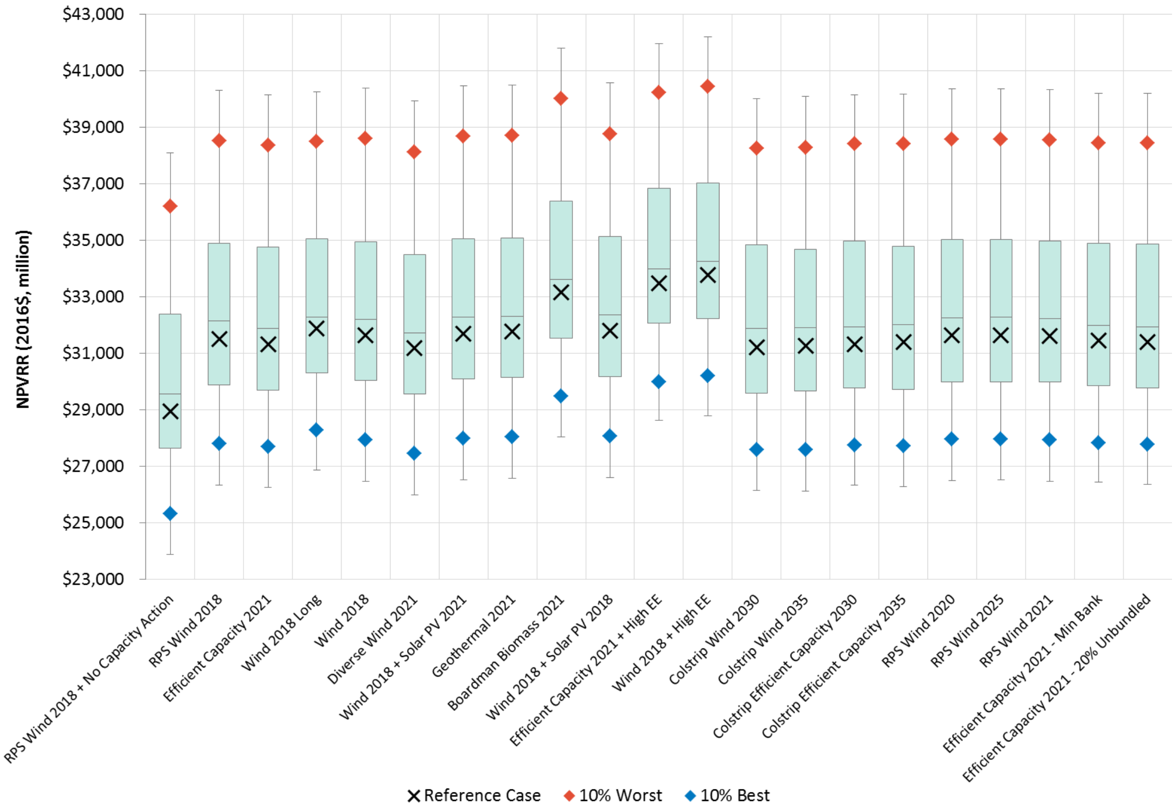


Figure 12-2 summarizes the NPVRR results across all 21 portfolios simulated against the futures described in Chapter 10, Modeling Methodology.

FIGURE 12-2: All portfolio costs across all futures



12.3 General Portfolio Conclusions and Consideration for Action Plan

As discussed in Chapter 10, Modeling Methodology, PGE models a number of resource portfolios in this IRP only for purposes of investigating specific questions or issues. For this reason, not all of the portfolios presented are included in the scoring process or considered for the Action Plan. Below is a summary of the findings for each of these portfolio groupings. Additional insights regarding the robustness of these findings across futures can be found in Appendix L, Supplemental Findings Across Futures.

12.3.1 RPS Timing

When considering an incremental physical RPS-qualifying resource, early action, which captures relatively more of the available PTC prior to phase-out, is preferable to deferring action. Given the portfolios assessed in this IRP, PGE's results demonstrate that procuring 175 MWa, with a resource commercial operation date (COD) in 2018 (*RPS Wind 2018* portfolio), results in a lower NPVRR than just-in-time compliance with the RPS obligation stair-step in 2020 (*RPS Wind 2020*). Further, acquisition of the full 2025 RPS compliance quantity in 2021 (*RPS Wind 2021*), to capture the last available tranche of PTC based on PGE's modeling assumptions in this IRP, results in a lower portfolio NPVRR than deferring this same resource action a full four years until 2025 and foregoing the PTC (*RPS Wind 2025*). The portfolio representing the 2018 resource action achieves a lower NPVRR relative to the portfolio including the 2021 resource action. A facility's qualification for a certain level of tax credit in this IRP is based on the begin construction date that results from a given COD and the assumed EPC duration as specified by third-party experts for this IRP (also discussed in Chapter 7, Supply Options). These assumptions do not reflect the possibility of a facility satisfying the safe harbor for a given level of tax credit with an EPC duration greater than the IRP assumption (and thus, a later COD for the same level of tax credit).

Table 12-1 summarizes the Reference Case NPVRR for each of the RPS timing portfolios. From these results, PGE draws the following conclusions:

- Acquiring a greater quantity of PTC-qualifying resources reduces the portfolio NPVRR;
- Capturing more of the PTC is less costly on a NPVRR-basis than deferring resource action within a reasonable time period; and
- Achieving the greatest quantity of PTC available, for a given resource type, results in the portfolio with the best combination of cost and risk when assessed using the scoring metrics discussed later in this Chapter.

For these reasons, PGE's Action Plan considers only those portfolios that include an RPS compliance strategy consistent with the acquisition of 175 MWa of RPS-qualifying resources eligible for 100 percent PTC (in 2018 under IRP).

TABLE 12-1: Portfolio comparison – RPS timing reference case NPVRR (2016$, millions)

RPS Wind 2018	RPS Wind 2020	RPS Wind 2021	RPS Wind 2025
$ 31,504	$ 31,630	$ 31,607	$ 31,641

12.3.2 Banked and Unbundled REC Usage

The portfolios just reviewed demonstrate that, given physical RPS compliance by 2025, capturing relatively more of the available PTC prior to phase-out, is preferable to deferring action. The portfolios discussed here explore the potential costs/benefits of foregoing the PTC in favor of pursuing the maximum potential deferral of incremental RPS resources. *Efficient Capacity 2021* follows the same RPS resource timing as *RPS Wind 2018*, but displaces a portion of that capacity resource by including an efficient combined cycle combustion turbine in 2021. *Efficient Capacity 2021 Minimum REC Bank* delays incremental RPS resource actions until 2025 in order to deplete the REC bank to its minimum recommended level. *Efficient Capacity 2021 20% Unbundled RECs* also defers incremental RPS resource actions until 2025; however, this portfolio includes an assumption that sufficient unbundled RECs are available to fill 20 percent of PGE's annual RPS obligation during the period 2016–2021.

Table 12-2 summarizes the NPVRR results for each of the REC usage portfolios on a Reference Case basis. PGE's analysis of these portfolios leads to the following conclusions:

a. The inclusion of a resource that is online in 2018 and achieves 100 percent PTC reduces the portfolio NPVRR relative to the modeled strategies for deferring acquisition of an RPS qualifying resource, even when deferral is enabled by unbundled RECs that are not explicitly priced; and

b. The greatest possible reduction in NPVRR that can be achieved by relying on unbundled RECs for up to 20 percent of PGE's annual RPS obligation during the period 2016–2021, relative to a similar strategy that does not acquire unbundled RECs, totals approximately $53 million on a present value basis. Table 12-2 summarizes this result.

As discussed in Chapter 10, Modeling Methodology, the regional supply of unbundled RECs is uncertain. As such, PGE's Action Plan presents a path to enable PGE's assessment of the availability and price of unbundled RECs in the market via a competitive bidding process. For that discussion, please see Chapter 13, Action Plan.

TABLE 12-2: Portfolio comparison – banked and unbundled RECs reference case NPVRR (2016$, millions)

Efficient Capacity 2021	Efficient Capacity 2021 Minimum REC Bank	Efficient Capacity 2021 20% Unbundled RECs
$ 31,319	$ 31,446	$31,392

Assuming the unbundled RECs were acquired in 2016 (for use through 2021), the price per unbundled REC to make the *Efficient Capacity 2021 Minimum REC Bank* and *Efficient Capacity 2021 20% Unbundled RECs* portfolios equivalent on an NPVRR basis is approximately $15 per unbundled REC—this represents the maximum average price that could be paid for the quantity of unbundled RECs. Twenty percent of the annual RPS obligation through 2021 amounts to approximately 3.6 million RECs. Table 12-3 details the derivation of this total REC quantity and maximum price. These amounts hold only for the assumptions included in the *Efficient Capacity 2021 Minimum REC Bank* and *Efficient Capacity 2021 20% Unbundled RECs* portfolios. Unbundled REC purchases at this price would not make the *Efficient Capacity 2021 20% Unbundled RECs* portfolio cost competitive with the *Efficient Capacity 2021* portfolio, in which RPS procurement occurs in 2018 to capture PTC benefits.

TABLE 12-3: Implied unbundled REC breakeven price

	2016	2017	2018	2019	2020	2021
RPS Obligation %	15%	15%	15%	15%	20%	20%
PGE REC Obligation (MWa)	307	309	310	312	417	424
20% of REC Obligation (MWa)	61	62	62	62	83	85
Annual Hours	8,784	8,760	8,760	8,760	8,784	8,760
20% of REC Obligation (RECs)	539,338	541,368	543,120	546,624	732,586	742,848
Total Unbundled RECs through 2021	3,645,883					
Maximum price per REC in 2016	= Maximum NPVRR benefit / Total Unbundled REC					
$15 / REC in 2016	= $53 million / 3,645,883					

12.3.3 Achieving Resource Adequacy

Chapter 5, Resource Adequacy, provides an extensive discussion regarding the importance of maintaining system reliability in the form of resource adequacy. PGE includes two portfolios in its analysis to estimate the cost impact of imposing such standard: 1) *RPS Wind 2018* adds generic capacity resources to maintain supply reliability, 2) *RPS Wind 2018 + No Capacity Action* instead exposes customers to market risk and does not procure long-term resources other than those needed to meet RPS, exposing customers to a loss of load expectation exceeding the one-day-in-10-years standard. Table 12-4 provides the Reference Case NPVRR results for these two portfolios, and highlights a cost difference of almost $2.5 billion over the period 2017-2050. For the reasons discussed in the resource adequacy chapter, all of PGE's Action Plan candidate portfolios have sufficient resource capacity to meet its reliability thresholds.

TABLE 12-4: Portfolio comparison – resource adequacy reference case NPVRR (2016$, millions)

RPS Wind 2018	RPS Wind 2018 + No Capacity Action
$ 31,504	$ 28,960

12.3.4 Diverse Wind Transmission Budget

PGE's treatment of incremental transmission costs for remote wind resources focuses on the present value cost difference between two portfolios that are identical, but for the wind resources:

1. *Diverse Wind 2021*, including a central Montana wind resource online in 2021 to provide approximately 212 MWa (approximately 505 MW nameplate capacity at a 42 percent capacity factor); and
2. *Wind 2018*, making use of an Oregon region wind resource to provide the same timing and quantity of energy (at a 34 percent capacity factor).

The modeled costs of both portfolios include PGE's cost assumptions for BPA transmission. As PGE discusses in Chapter 7, Supply Options, the a priori assumption is for the capacity factor and capacity contribution advantages of the central Montana wind resource to reduce costs when that resource is included in a portfolio, relative to a portfolio comprising PNW Wind. The difference in cost between those two portfolios can serve as a reasonable proxy for the budget that could be allocated to securing the transmission capability needed in order to deliver the energy from a Montana wind resource.

Table 12-5 provides the Reference Case NPVRR result for the two portfolios used in this comparison.

TABLE 12-5: Portfolio comparison – remote wind reference case NPVRR (2016$, millions)

Wind 2018	Diverse Wind 2021
$ 31,652	$ 31,178

The results indicate approximately $474 million in present value benefit to the portfolio including the Montana wind resource over the period 2017–2050. When focusing more specifically on the period over which the wind resources differ, beginning in 2021, the present value benefit (in 2016 dollars) is approximately $557 million. On a real-levelized basis, this equates to approximately $33 million per year over the period 2021–2050 (in 2016$), or about $65 per kW-year based on PGE's assumed 42 percent capacity factor for the Montana wind resource.

Given this framework for assessing the potential costs and benefits of diverse wind, PGE does not include these portfolios explicitly in the development of the Action Plan. PGE will, however, use this information to inform the Company's decision-making as it considers future resource actions.

12.3.5 Renewable Resource Economics

To assess the relative economics of various renewable resources, PGE isolates each resource's costs and benefits by modeling portfolios representing different combinations of resource options. At least one portfolio isolating a specific renewable technology of those eligible for inclusion in PGE's resources portfolios is present in the portfolio analysis (also discussed in Chapter 7, Supply Options). The renewables resources included are:

- PNW wind (Oregon Gorge)
- Montana wind
- Single-axis tracking solar PV
- Geothermal
- Biomass (Boardman Biomass Project).

For the purpose of making resource comparisons, the *Wind 2018* portfolio, which incorporates PNW wind additions of 175 MWa in 2018 and 212 MWa in 2021, serves as a basis. From this starting point, the NPVRRs of four portfolios helps to draw conclusions regarding resource economics.

Two portfolios allow for comparisons with solar PV:

- *Wind 2018 + Solar PV 2018* displaces 50 MWa of PNW wind with solar PV in 2018, thus foregoing the PTC in favor of capturing the full 30 percent investment tax credit (ITC); and
- *Wind 2018 + Solar PV 2021* adds 50 MWa of solar PV in lieu of wind in 2021, when wind qualifies for 40 percent PTC and solar achieves 26 percent ITC.

All portfolios achieve comparable levels of resource adequacy by incorporating the ELCC of the variable resources in each portfolio. The overnight capital cost for solar PV is forecast to decline at a more rapid rate than that of wind. The comparison of these two solar PV portfolios with the base portfolio demonstrates that, on a portfolio NPVRR basis, displacing wind with solar PV in 2018 or 2021 does not reduce portfolio NPVRR.

Geothermal and biomass resources both displace wind in 2021, with the associated adjustment to capacity, and they both increase the cost on a NPVRR bases when compared to *Wind 2018*.

Chapter 7, Supply Options, provides additional information regarding each of the above-referenced resources. Table 12-6, below, reports the NPVRR results for these portfolios, under Reference Case conditions. Later in this chapter, PGE provides further consideration of each of these portfolios in order to assess their relative risk profiles.

TABLE 12-6: Portfolio comparison – renewable resources reference case NPVRR (2016$, millions)

Wind 2018	Wind 2018 + Solar PV 2018	Wind 2018 + Solar PV 2021	Geothermal 2021	Boardman Biomass 2021
$ 31,652	$ 31,792	$ 31,705	$ 31,769	$ 33,173

12.3.6 Efficient Capacity versus Low Capital Cost Capacity

PGE's analysis includes two portfolios that provide the basis for comparing the economics of efficient capacity resources relative to capacity resources that minimize expected capital costs. *RPS Wind 2018* incorporates the generic capacity resource modeled on the parameters consistent with a frame combustion turbine (7F.05), while, as mentioned previously, the *Efficient Capacity 2021* portfolio displaces a portion of that capacity resource by including an efficient combined cycle combustion turbine in 2021. The Reference Case NPVRR results for these two portfolios are provided in Table 12-7 below, reflecting an approximately $200 million benefit for the portfolio containing efficient generation based on economic dispatch modeling.

TABLE 12-7: Portfolio comparison - efficient capacity reference case NPVRR (2016$, millions)

RPS Wind 2018	Efficient Capacity 2021
$ 31,504	$ 31,319

12.3.7 Colstrip Timing Economics

PGE outlined a need to assess the relative economics of two potential dates for displacement of Colstrip Units 3 and 4 from PGE's retail portfolio: year-end 2029 and year-end 2034. For each of those dates, PGE considers two alternate resources: 1) a resource consistent with PGE's assumptions for Montana-sited wind and, 2) an efficient capacity resource with parameters in-line with those of an H-class combined cycle combustion turbine. Similar assumptions apply to the modeling of a Montana-sited wind resource with regard to expected incremental transmission costs as were discussed previously for the *Diverse Wind 2021* portfolio.

With respect to replacement timing, the same directional findings were observed for both the Montana-sited wind and the H-class combined cycle replacement scenarios. In both cases, the Reference CO_2 and Gas Price future favors earlier replacement. This result also holds under the futures with High CO_2 Price conditions and Reference Gas and High Gas Price conditions. This finding, however, is not robust under all possible future conditions. A relatively later replacement date is favored under simulated market conditions consistent with PGE's Reference CO_2 Price with High Gas Prices, as well as futures with No CO_2 Price and Reference or High Gas Price futures.

As the conclusions under PGE's Reference Case conditions do not hold across various CO_2 and Gas price futures, Table 12-8 below presents the NPVRR results for each of the above-discussed six scenarios. Additional discussions of Colstrip and emission considerations are available in Chapter 3, Planning Environment, and Chapter 10, Modeling Methodology.

Given the time horizon for PGE's Action Plan in this IRP, PGE does not consider these portfolios in the portfolio scoring process.

TABLE 12-8: Portfolio comparison – Colstrip replacement timing under various futures NPVRR (2016$, millions)

	Colstrip Wind 2030	Colstrip Wind 2035	Colstrip Efficient Capacity 2030	Colstrip Efficient Capacity 2035
Ref. CO_2, Ref. Gas	$ 31,213	$ 31,278	$ 31,328	$ 31,393
Ref. CO_2, High Gas	$ 35,088	$ 35,067	$ 35,291	$ 35,242
No CO_2, Ref. Gas	$ 27,873	$ 27,837	$ 28,050	$ 27,988
No CO_2, High Gas	$ 32,062	$ 31,916	$ 32,211	$ 32,029
High CO_2, Ref. Gas	$ 32,437	$ 32,552	$ 32,474	$ 32,596
High CO_2, High Gas	$ 36,268	$ 36,332	$ 36,402	$ 36,428

12.3.8 Economics of Non-Cost Effective Energy Efficiency

PGE tested the economic performance of non-cost effective energy efficiency (non-cost effective EE) using two portfolios as starting points: 1) the *Wind 2018* portfolio, which incorporates incremental Oregon region wind and generic capacity resources; and 2) the *Efficient Capacity 2021* portfolio, which includes incremental Oregon region wind, efficient capacity generation, and generic capacity resources. With either of these portfolios as the base, the addition of non-cost effective EE reduces the incremental resources needed to meet resource adequacy and RPS obligations. Under Reference Case conditions, the inclusion of non-cost effective EE increases the portfolios' NPVRR. While the portfolios become more costly, the addition of non-cost effective EE does seem to make the portfolios less sensitive to increases in CO_2 and natural gas prices relative to the similar portfolios that do not include the additional EE (that is, *Wind 2018* vs. *Wind 2018 + High EE*, and *Efficient Capacity 2021* vs. *Efficient Capacity 2021 + High EE*). This finding is addressed further in Section 12.5, Portfolio CO2 Emissions Analysis and Section 12.6, Natural Gas Price Futures Analysis below.

Additional discussions of the EE forecast, including the cost-effectiveness determination and assumptions for the costs of EE included in PGE's portfolios, are provided in Chapter 6, Demand Options. Table 12-9 displays the NPVRR results for these portfolios under Reference Case conditions. Section 12.8, Application of Portfolio Scoring Metrics, considers each of these portfolios further below in order to assess their relative risk profiles.

TABLE 12-9: Portfolio comparison – non-cost effective EE reference case NPVRR (2016$, millions)

Wind 2018	Wind 2018 + High EE	Efficient Capacity 2021	Efficient Capacity 2021 + High EE
$ 31,652	$ 33,768	$ 31,319	$ 33,476

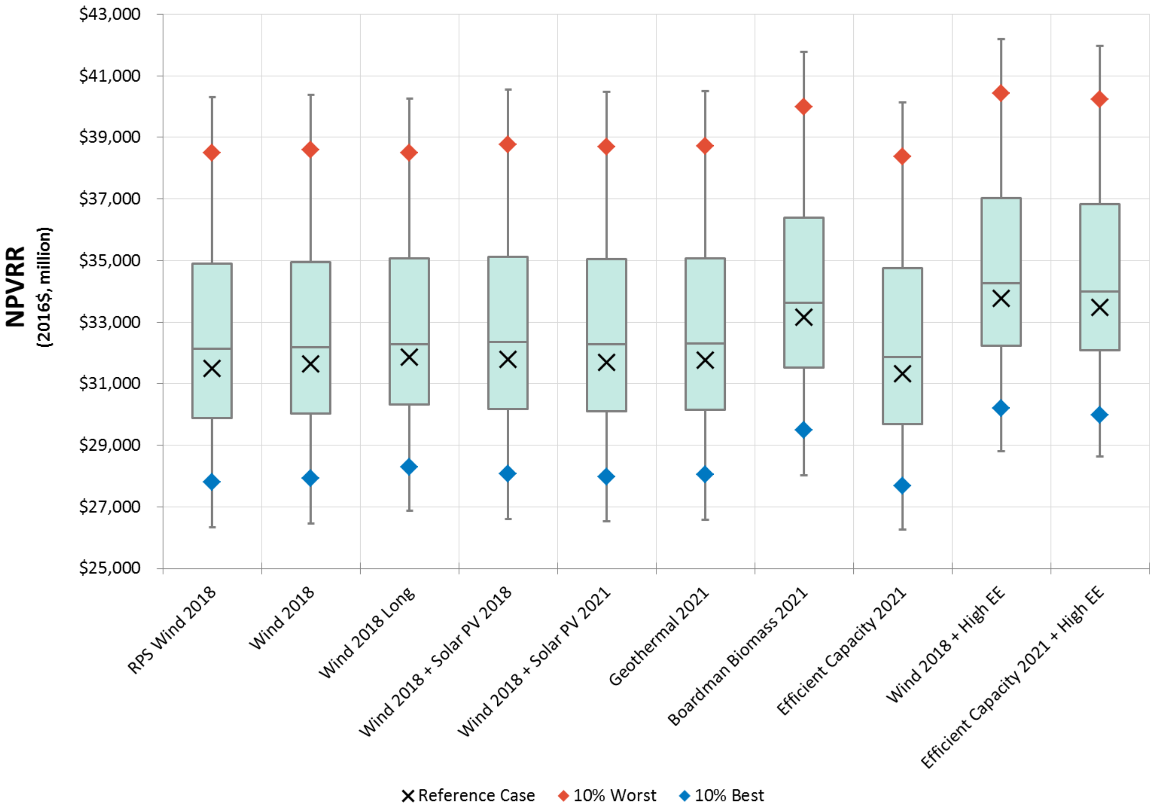
12.4 Action Plan Portfolios

As discussed above and in Chapter 10, Modeling Methodology, a number of portfolios were assessed with the intention of using those results to answer specific questions. Generally, these portfolios include potentially incomplete resource cost estimates, include a primary resource action that is beyond the Action Plan time horizon in this IRP, or fail to plan for achieving PGE's established resource adequacy targets. For these reasons, PGE narrows the set of portfolios that are considered for the Action Plan in this IRP. The Company considers ten portfolios in the scoring and analysis that informed the 2016 IRP Action Plan:

- *RPS Wind 2018*
- *Wind 2018*
- *Wind 2018 Long*
- *Wind 2018 + Solar PV 2018*
- *Wind 2018 + Solar PV 2021*
- *Geothermal 2021*
- *Boardman Biomass 2021*
- *Efficient Capacity 2021*
- *Wind 2018 + High EE*
- *Efficient Capacity 2021 + High EE*

Figure 12-3 presents a box-and-whisker plot, similar to Figure 12-2, for this refined set of portfolios.

FIGURE 12-3: Portfolio cost distribution



Visual inspection of Figure 12-3 reveals that several portfolios appear to have generally higher-costs, while others exhibit relatively similar performance. In the following sections, PGE provides a review of portfolio performance under the three key risk drivers of PGE's futures analysis: CO_2 prices, natural gas prices, and load growth. Overall, seemingly small margins differentiate portfolio performance. Using the specific scoring metrics discussed in Chapter 11, Scoring Metrics allows for a more structured approach to discerning portfolio performance. Following the overview of portfolio performance across the main risk drivers, PGE discusses the scoring metrics, and their application to portfolio results.

12.5 Portfolio CO_2 Emissions Analysis

Oregon IRP guidelines require utilities to examine several carbon compliance scenarios in order to estimate the potential impact of carbon costs on candidate portfolios and potential resource selections (Guideline 8, Order No. 08-339). To comply with this guideline, PGE performed the following analysis:

1. Identified the most likely regulatory compliance future for CO_2. Chapter 3, Planning Environment, discusses PGE's expectations and modeling approach for future CO_2 regulation in this IRP.
2. Considered additional compliance scenarios. Chapter 3, Planning Environment, and Chapter 10, Modeling Methodology describe the scenarios PGE considered, ranging from zero

effective CO_2 price level to an effective price for CO_2 potentially capable of achieving a 90 percent below 2005 level of CO_2 emissions in the country by 2050.

3. Tested the resource portfolios against the compliance futures. The CO_2 compliance futures are key components of the futures tested in the broader portfolio analysis.
4. Determined the CO_2 "trigger point". This is the effective CO_2 price that may result in the selection of a portfolio of resources substantially different from the preferred portfolio. Section 12.5.3, *Trigger-Point CO2 Price Analysis* provides more details regarding the trigger point analysis.
5. Identified a *2050 Oregon GHG Goal* portfolio consistent with Oregon's greenhouse gas reduction goals (Oregon House Bill 3543).

Utilities can achieve greenhouse gas limitations or reductions using several alternative policy and regulatory measures. Examples include: emission taxation schemes, emission limits, cap and trade systems, and bans on certain technologies. Regardless of the actual regulatory instrument, modeling a tax on CO_2 emissions is a simplified and common practice of quantifying the potential cost associated with CO_2.

PGE analyzed the impact of potential CO_2 regulatory costs from zero to more than $200 (all dollar amounts and growth rates are nominal unless otherwise noted) per short ton by 2050 on each of the portfolios. Additionally, PGE assessed two "trigger-point" futures with CO_2 costs beginning at approximately $150 and $300 per ton in 2022; these two futures are discussed in Section 12.5.3, Trigger-Point CO2 Price Analysis. As described in detail in Chapter 3, Planning Environment, and in Chapter 10, Modeling Methodology, the CO_2 futures included in this IRP are:

Reference CO_2 Price

Under the Reference Case, PGE reflects a national CO_2 emission allowance trading scheme that results in an effective price of CO_2 emissions beginning in 2022 equivalent to approximately $22 per short ton. This effective CO_2 price, consistent with Synapse Energy Economics' "Mid Case", as published in the "Spring 2016 National Carbon Dioxide Price Forecast", escalates at 5 percent annually through 2030 and 8 percent annually thereafter for the duration of the analysis horizon. As discussed in Chapter 3, Planning Environment, this "Mid Case" reflects an environment in which, "Clean Power Plan compliance is achieved and science-based climate targets mandate at least an 80 percent reduction in electric section emissions from 2005 levels by 2050."[211]

No Effective CO_2 Price

This future reflects a state in which additional CO_2 emission reduction goals beyond the Clean Power Plan are not binding constraints for the power sector, or CO_2 emissions do not incur an explicit cost. PGE models the California cap and trade, as well as Alberta and British Columbia taxes, are, however, modeled in their respective jurisdictions.

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[211] "Spring 2016 National Carbon Dioxide Price Forecast." Dated March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008_0.pdf

High CO_2 Price

Under the High CO_2 Price future, CO_2 emissions incur a cost of $28 per short ton starting in 2022 and escalating at approximately 6 percent annually through 2027 and 8 percent annually, thereafter, through 2050. This effective CO_2 price is consistent with Synapse Energy Economics' "High Case." The "High Case" reflects an environment with:

> *"a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2027. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector."* [212]

This scenario may also be representative of other elements leading to higher costs of emissions reductions, such as offset use restrictions, high cost of resource alternatives, and additional international actions.

Section 12.5.3, Trigger-Point CO2 Price Analysis, discusses the trigger-point CO_2 price future.

12.5.1 Portfolio Economic Performance Against CO_2 Compliance Scenarios

All candidate resource portfolios in this IRP share existing resources (until at least 2030), at least a minimum-level of RPS resource acquisitions over time, and various forms of incremental capacity resources that PGE models as natural gas-fired generation. Therefore, the imposition of CO_2 prices has similar effects across portfolios. Figure 12-4 shows the performance of the Action Plan candidate portfolios under the various CO_2 price futures on an NPVRR basis.

The *Efficient Capacity 2021* portfolio is the least cost on an NPVRR basis across the three futures while testing just the CO_2 pricing assumption and holding the natural gas price forecast and load forecast constant.

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[212] "Spring 2016 National Carbon Dioxide Price Forecast." Dated March 16, 2016. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008_0.pdf

FIGURE 12-4: Portfolio cost by CO_2 future (reference case gas and reference case load)

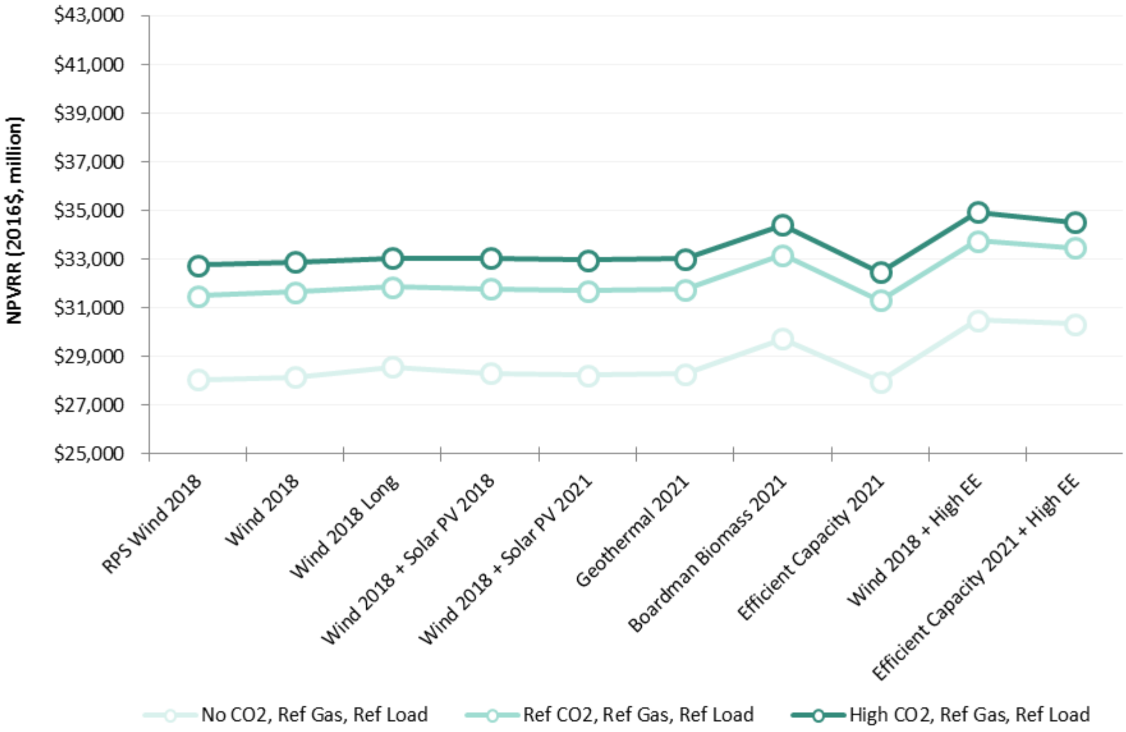


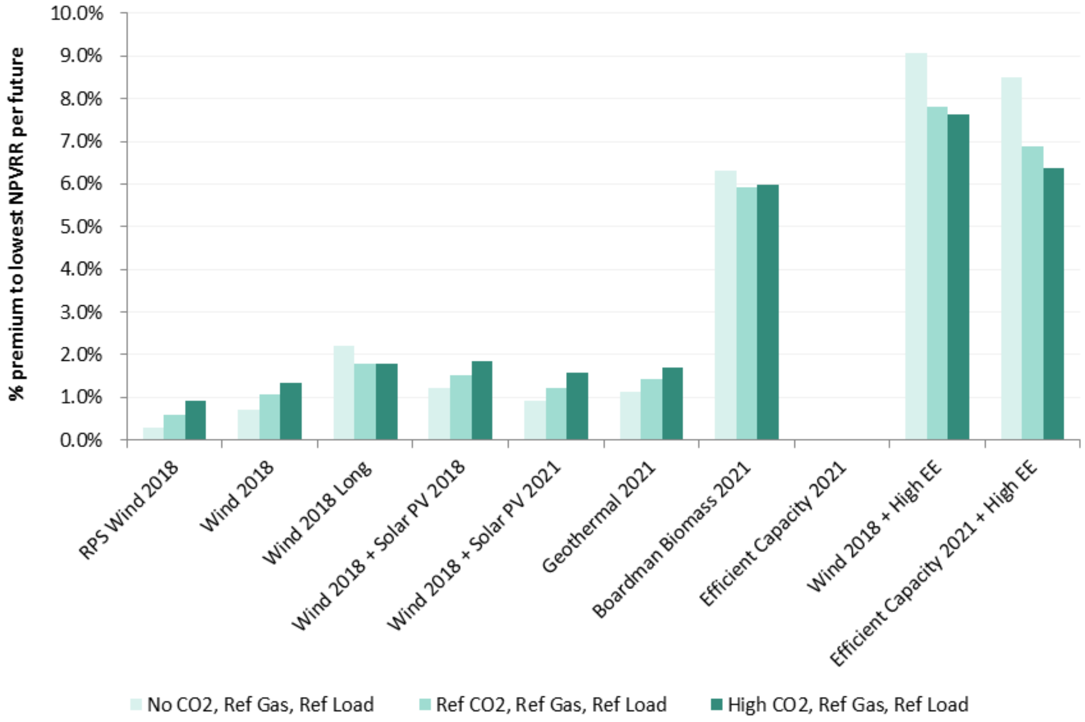
Figure 12-5 reflects the relative performance of the same set of portfolios across the CO_2 price futures on a relative basis normalized to the lowest cost portfolio in each future. Applying this view, it becomes easier to identify the relative changes in performance of the portfolios under the various futures.

The *RPS Wind 2018* portfolio, which only procures renewable resources for RPS compliance and meets resource adequacy targets with generic capacity resources, has the lowest premium to *Efficient Capacity 2021* across the same three CO_2 futures as referenced above.

The composition of the *RPS Wind 2018* portfolio leaves it potentially more exposed to high market prices. These prices may persist under an environment similar to the High CO_2 Price future analyzed here. Similar results appear to be true of the *Wind 2018*, *Wind 2018 + Solar PV 2018*, *Wind 2018 + Solar PV 2021*, and *Geothermal 2021*. All of these portfolios procure renewables sufficient to meet load through 2021, and then in a manner consistent with maintaining a minimum REC bank balance through 2040 and physical compliance in 2040, 2045, 2050 (as described in Chapter 10, Modeling Methodology).

Portfolios procuring renewables beyond the RPS targets and/or pursuing greater amounts of EE are more expensive than those described in the above paragraph; however, these portfolios get more cost-competitive as the effective CO_2 price increases. That is, the relative premium associated with these more renewable- and energy efficiency-intensive portfolios declines under higher CO_2 price futures.

FIGURE 12-5: Portfolio premium to lowest cost by CO_2 future (reference case gas / load)



12.5.2 Portfolio CO_2 Emissions

PGE computes resource and portfolio CO_2 emissions using the following approximate emissions factors:

- Coal-fired plants: 205 lbs/MMBtu;
- Natural gas-fired plants: 117 lbs/MMBtu;
- Biomass, geothermal, wind, and solar energy resources: no net carbon emissions;
- Long-term contracts: no carbon emissions for hydro or renewable resources, or associated contracts; and,
- Net market purchases: PGE assigns market purchases / sales an emissions factor of approximately 0.45 lbs/MWh. This emissions factor, which is consistent with PGE's assumption for similar analyses in past IRPs, is lower than the average emissions factor of the marginal unit in the West observed in PGE's simulations, and is closer to the emissions factor of an existing combined cycle resource. Use of this assumption does not overestimate the emissions impacts of displacing carbon-intensive generation elsewhere in the West by selling into the market.

Under Reference Case conditions, Figure 12-6 illustrates the CO_2 intensity (tons of CO_2 emissions per MWh) on an annual basis for the Action Plan candidate portfolios.

FIGURE 12-6: Reference case CO_2 intensity by portfolio

Over the study horizon in this IRP, all portfolios' emissions intensities decline. Generally, this long-term decline appears to coincide with either 2035 or 2040. The reductions in those years are driven by displacement of Colstrip Units 3 and 4 from all portfolios by 2035 and compliance with Oregon RPS, drive the reduction in those years.

The timing and quantity of renewable resource additions to comply with RPS obligations are dictated by the minimum REC banking targets described in Chapter 10, Modeling Methodology. Portfolios with relatively larger renewable resource additions in 2035 (e.g., *Efficient Capacity 2021* and *RPS Wind 2018*) demonstrate relatively larger reductions in portfolio emissions beginning in that year. Portfolios with more measured, but still sizeable, additions of renewables in 2035 and 2040 reflect corresponding emissions reductions.

All Action Plan candidate portfolios achieve roughly the same level of emissions reductions by 2040. The difference in emissions intensity from that point forward is attributable to additional (non-cost effective) energy efficiency, efficient capacity generators, and the interaction of those two with the assumed emissions intensity of market purchases. On the margin, resource actions are assumed to displace market purchases.

Portfolios pursuing earlier renewable resource additions (e.g., *Wind 2018 Long*) demonstrate relative reductions over the period 2021–2035, because those zero-emitting resource actions displace energy that would otherwise be served with market purchases bearing an emissions intensity of approximately 0.45 tons per MWh. That advantage erodes by 2035 as the quantity of zero-emitting resources in other portfolios exceeds that of the portfolios pursuing earlier renewables acquisition.

Across the time period 2017–2050, portfolios that include efficient capacity resources demonstrate reduced emissions intensity relative to portfolios that have identical quantity and timing of renewable resource additions, but differ with respect to the resources added to achieve resource adequacy. For example, *RPS Wind 2018* and *Efficient Capacity 2021* share identical RPS compliance strategies, where these portfolios differ is the resource used to achieve capacity adequacy in 2021. *RPS Wind 2018* includes the generic capacity resource (similar to a Frame combustion turbine) and *Efficient Capacity 2021* includes an efficient capacity resource (similar to an H-class combined cycle combustion turbine). As the generic capacity resource dispatches relatively infrequently against market heat rates, under Reference Case conditions, it displaces few market purchases. The efficient capacity resource, on the other hand, dispatches more often. Each unit of energy generated by this resource has an emissions intensity that is approximately 85 percent of that assigned to market purchases. The emissions intensity of the efficient capacity resource is:

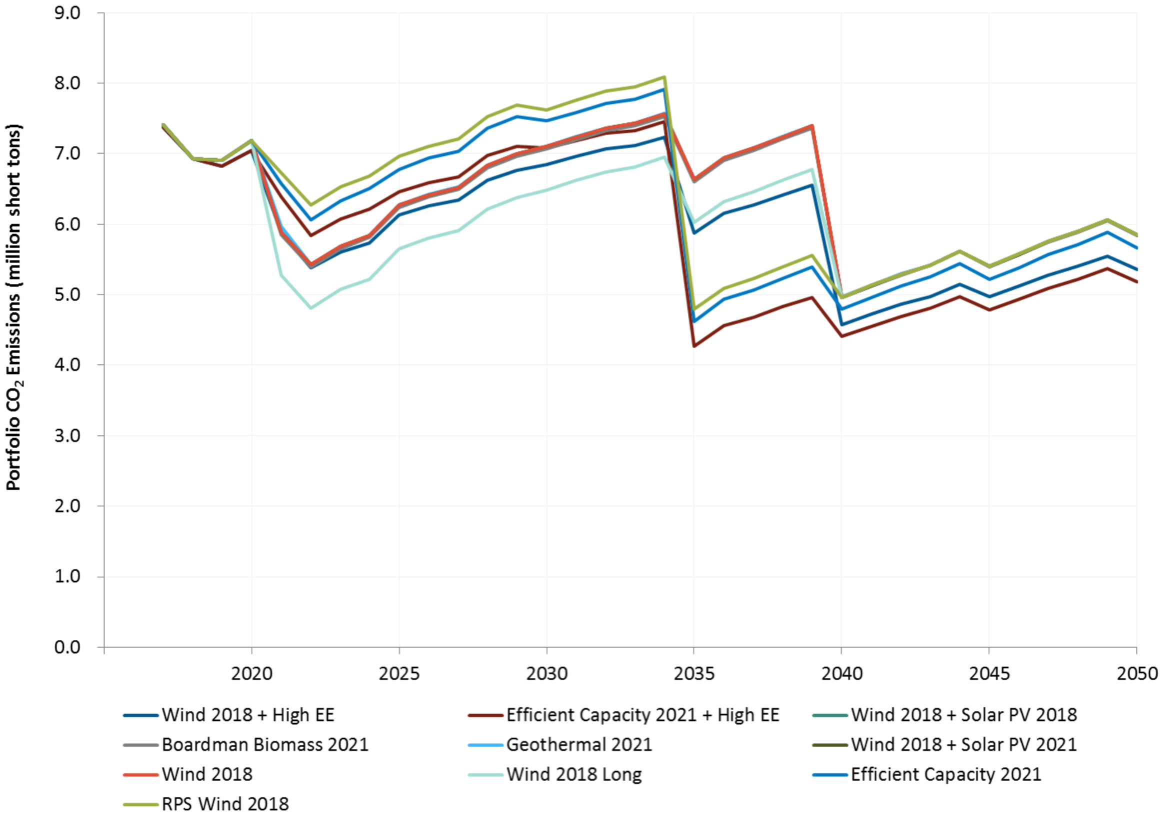
$$\frac{\text{tons}}{\text{MWh}} = \frac{6.5\ \text{MMBtu}}{1\ \text{MWh}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} \times \frac{117\ \text{lbs}\ CO_2}{1\ \text{MMBtu}} \sim 0.38\ \text{tons}\ CO_2\ \text{per MWh}$$

Thus, including the efficient capacity resource in a portfolio reduces the emissions intensity of that particular portfolio.

Another driver of differences in portfolio emissions intensities, after accounting for renewable resource additions, is the presence of EE beyond the cost effective amount included across all portfolios. Additional EE effectively allows those portfolios to avoid market energy purchases and their associated emissions. As a result, *Efficient Capacity 2021 + High EE* is the portfolio with the lowest emissions intensity, followed by *Wind 2018 + High EE*.

Total portfolio CO_2 emissions follow a similar trajectory to the emissions rates discussed above in this section. See Figure 12-6.

FIGURE 12-7: Reference case CO_2 emissions (million short tons) by portfolio



The CO_2 emissions portrayed in Figure 12-7 generally have an upward trajectory, with the same step-downs in 2035 and 2040 as noted above. This upward trajectory relates to the assumption that market purchases and sales of energy are used to balance the portfolio demand in each time-step. To the extent that PGE forecasts demand growth between modeled resource additions in the portfolios, PGE meets the incremental demand with market purchases and attributes their associated CO_2 emissions to the portfolio. The upward drift in CO_2 emissions observed in Figure 12-7 is not present to the same extent in the load-normalized emissions shown in Figure 12-6.

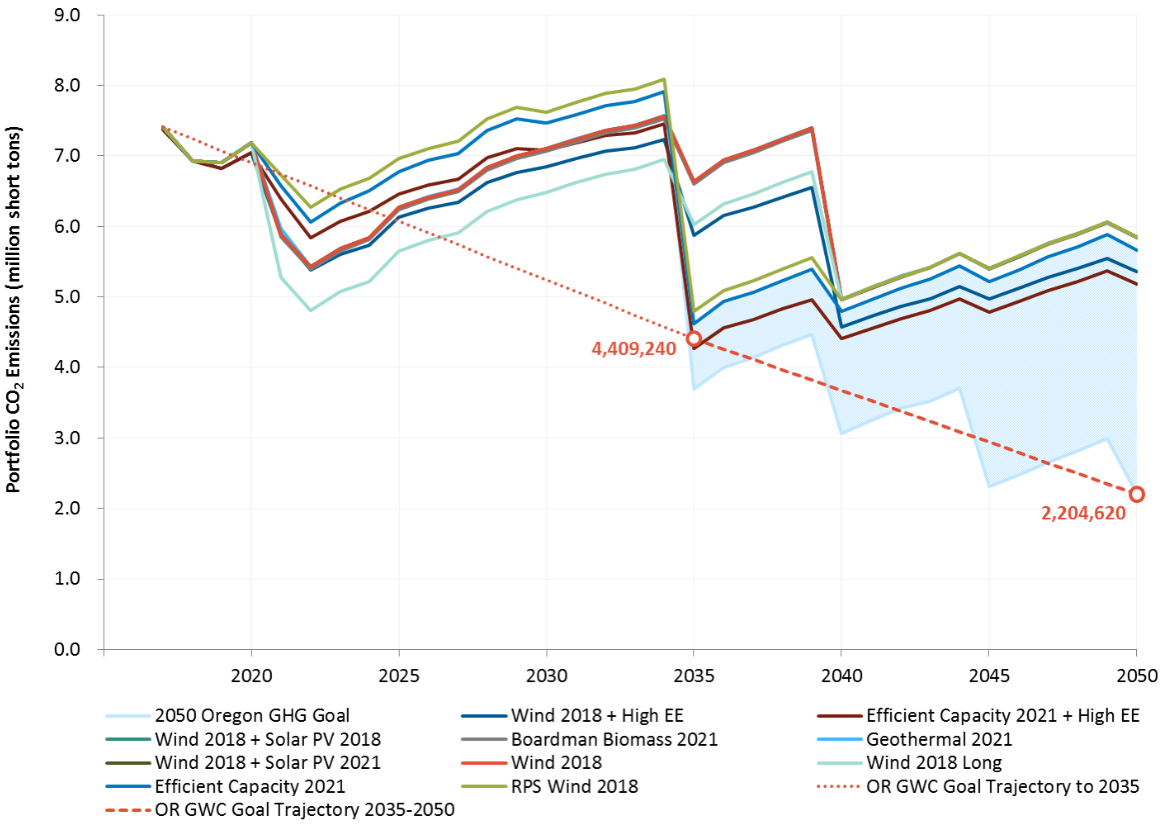
In 2007, the Oregon Legislature adopted the recommendations of the Oregon Advisory Group on Global Warming and established an end-goal of 75 percent reduction from 1990 levels by 2050. In the same year, the Advisory Group recommended an intermediate goal of 10 percent below 1990 levels by 2020. In its 2015 Biennial Report to the Legislature, the Advisory Group recommended a new intermediate target be established, which targets emissions reductions by 2035. As 2020 is nearly here, and the established state goal for that year is unlikely to be achieved, the 2035 goal serves at least two important objectives according to the 2015 Report: 1) allows for a meaningful basis to assess near-term actions, and 2) provides the impetus to undertake the noted “ambitious actions” necessary to position the state for achieving the 2050 goal. The 2015 Biennial Report includes emissions targets for PGE based on both the 2035 intermediate target and the 2050 goal.

These 2035 and 2050 goals result in emissions targets for PGE of four million metric tons, and two million metric tons of CO_2 emissions, respectively.[213]

In 1990, PGE relied extensively on both nuclear and hydro resources, both of which have no associated carbon emissions. Nuclear and hydro resources covered approximately 1,200 MWa, or 62 percent, of PGE customers' energy requirements in 1990. Since that time, the Company closed the Trojan nuclear plant, has steadily been losing access to legacy hydro contracts via expiration, and has replaced large portions of this zero carbon power with natural gas-fired plants and power purchased in the wholesale market, both of which have associated greenhouse gas emissions as discussed above.

PGE uses the trajectory of emissions reductions between the 2035 and 2050 targets to design a portfolio that achieves both goals (the *2050 Oregon GHG Goal* portfolio). Figure 12-8 overlays the intermediate target, the 2050 goal, and the emissions from this *2050 Oregon GHG Goal* portfolio to depict the CO_2 emissions reductions, relative to the Action Plan candidate portfolios tested in this IRP, necessary to achieve the stated 2050 goal.

FIGURE 12-8: CO_2 emissions (million short tons) by portfolio



From Figure 12-8, it appears that several portfolios are very close to achieving the 2035 intermediate target: *Efficient Capacity 2021 + High EE*; *Efficient Capacity 2021*; and *RPS Wind 2018*. As mentioned

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[213] One Metric ton is equivalent to 1.10231 short tons (or "tons"), the measurement used in PGE's analysis.

above, portfolio emissions in 2035 are driven, in part, by the timing of renewable resource additions given the RPS compliance needs. Between 2035 and 2050, all resource portfolios considered for the Action Plan diverge from the trajectory needed to achieve the 2050 goal.

PGE constructed the *2050 Oregon GHG Goal* portfolio with *Efficient Capacity 2021* as the starting point. Through 2034, the two portfolios are identical. As a modeling approach, PGE designed the *2050 Oregon GHG Goal* portfolio to meet the average emissions target across five-year periods beginning in 2035. The emissions targets are met by adding renewable resources to displace emissions from market purchases. Table 12-10 summarizes the incremental renewables (beyond those included for RPS compliance) in this portfolio.

TABLE 12-10: Incremental renewables to achieve 2050 Oregon CO_2 goal (cumulative MWa)

	2035	2040	2045	2050
Existing RPS Qualifying Resources (base)	330	302	302	302
Efficient Capacity 2021 (incremental)	854	1,045	1,137	1,239
2050 Oregon GHG Goal portfolio (incremental)	237	438	735	876
Total Incremental Renewable (MWa)	1,090	1,483	1,872	2,115

The shaded region in Figure 12-8 represents the difference in emissions between the two portfolios from 2035 through 2050. This is approximately the quantity of emissions reductions needed to maintain the trajectory towards the 2050 goal. As mentioned previously, the *2050 Oregon GHG Goal* portfolio achieves the modeled level of CO_2 emissions by effectively displacing market emissions that are assigned an intensity of 0.45 tons per MWh. A similar level of emissions reductions could potentially be achieved by displacing other resources from the portfolio. To the extent these resources have emissions intensities less than that assumed for the market, achieving the same level of emissions reductions would require relatively more zero-emitting resources. *Efficient Capacity 2021* includes sufficient renewable resources to achieve the RPS targets of 50 percent of retail load enacted pursuant to Senate Bill 1547. For comparison, the quantity of renewable resources included in the *2050 Oregon GHG Goal* portfolio would represent nearly 80 percent of retail load in 2050:

$$\frac{302\ (\text{base MWa}) + 2{,}115\ (\text{incremental MWa})}{3{,}082\ (\text{MWa load})} = 78.4\%$$

12.5.3 Trigger-Point CO_2 Price Analysis

The general intent for this analysis is to identify an effective CO_2 price level at which the cost of a substantially different alternative portfolio (i.e., one that achieves substantially lower CO_2 emissions, or comprises substantially different resources) reaches cost parity with PGE's Preferred Portfolio. As reflected in Figure 12-6, over time, all portfolios tested in this IRP achieve significant reductions in CO_2 emissions intensity. By 2040, all portfolios deliver sufficient energy from renewable resources to meet 50 percent of PGE's retail load. Differences in resource composition are largely related to the types of incremental renewable resources included and the types of resources used to maintain resource adequacy. PGE investigates the results of *Efficient Capacity 2021* and *Wind 2018 Long* in this analysis.

Efficient Capacity 2021

The portfolio procures renewables to meet RPS targets, an efficient CCCT in 2021, and fills the remaining capacity need with generic capacity resources. This is the least-cost portfolio under Reference Case assumptions among the Action Plan candidate portfolios.

Wind 2018 Long

Wind 2018 Long tests a strategy that procures renewable resources (Oregon-sited Columbia River Gorge wind, in this case) in a quantity that is approximately energy-equivalent to a CCCT on an availability basis in 2021. This 2021 addition is incremental to 175 MWa added in 2018. REC banking considerations discussed in Chapter 10, Modeling Methodology, inform future renewable resource additions to the portfolio. The portfolio includes a sufficient quantity of the generic capacity resource to meet PGE's reliability standard.

PGE tested successively higher prices for CO_2 emissions, up to $500 per ton on a real-levelized basis (2016 dollars), in order to help identify a point at which the portfolio preference changed on a cost-basis. These emissions prices follow the same beginning year (2022) as the Reference and High CO_2 futures, and apply the same trajectory as the Reference Case CO_2 prices; however, the starting price is varied. At the $500 per ton (real-levelized) level, the difference in portfolio NPVRR between the two portfolios has been reduced by more than 90 percent relative to the difference present under Reference Case conditions (see Table 12-11).

TABLE 12-11: NPVRR impact of increasing CO_2 prices (2016$, millions)

	Efficient Capacity 2021 [1]	Wind 2018 Long [2]	[2] less [1]
No CO_2, Ref. Gas	$ 27,972	$ 28,594	$ 618
Ref. CO_2, Ref. Gas	$ 31,319	$ 31,875	$ 556
High CO_2, Ref. Gas	$ 32,466	$ 33,043	$ 577
$235 CO_2, Ref. Gas	$ 44,763	$ 45,108	$ 345
$500 CO_2, Ref. Gas	$ 64,163	$ 64,214	$ 51

Several factors may play a role in the finding that a seemingly very high CO_2 price is needed to arrive at this outcome. One contributing factor may be that the resource portfolios tested in this IRP all include sufficient renewables to comply, on a physical basis, with Oregon's 50 percent RPS obligation by 2040. Additionally, differences in the resource composition across candidate portfolios may be not be significant enough to affect the intended result of this exercise as the incremental resource additions beyond 2021 are all either renewables or generic capacity. Finally, all portfolios in this IRP show a marked reduction in CO_2 intensity (emission per MWh served), as depicted in Figure 12-6 through Figure 12-8, above. This reduction is due to the relatively low emissions levels of resources considered: high-efficiency gas plants, renewables, and energy efficiency, which are the lowest carbon emitting resources currently available at scale in the market.[214]

12.6 Natural Gas Price Futures Analysis

Natural Gas represents the second key risk factor driving the futures in this IRP. As discussed in Chapter 10, Modeling Methodology, PGE analyzes two natural gas price futures: 1) Reference Case, and 2) High Case. The *Efficient Capacity 2021* portfolio is the least cost on an NPVRR basis under these two futures while holding the CO_2 price and load forecast constant. Figure 12-9 reflects these results.

FIGURE 12-9: Portfolio performance by natural gas future (reference case CO_2 / load)

Figure 12-10 reflects the relative performance of the Action Plan candidate portfolios across the natural gas price futures, normalized to reflect the percentage premium relative to the lowest cost portfolio in each future (*Efficient Capacity 2021*). Focusing on the relative performance of the portfolios under the two natural gas price futures, several observations can be made:

1. The *RPS Wind 2018* portfolio again has the lowest premium to *Efficient Capacity 2021* under both the Reference Gas Price and High Gas Price natural gas futures.
2. All else equal, higher gas prices tend to reduce the portfolios' premiums to *Efficient Capacity 2021*.

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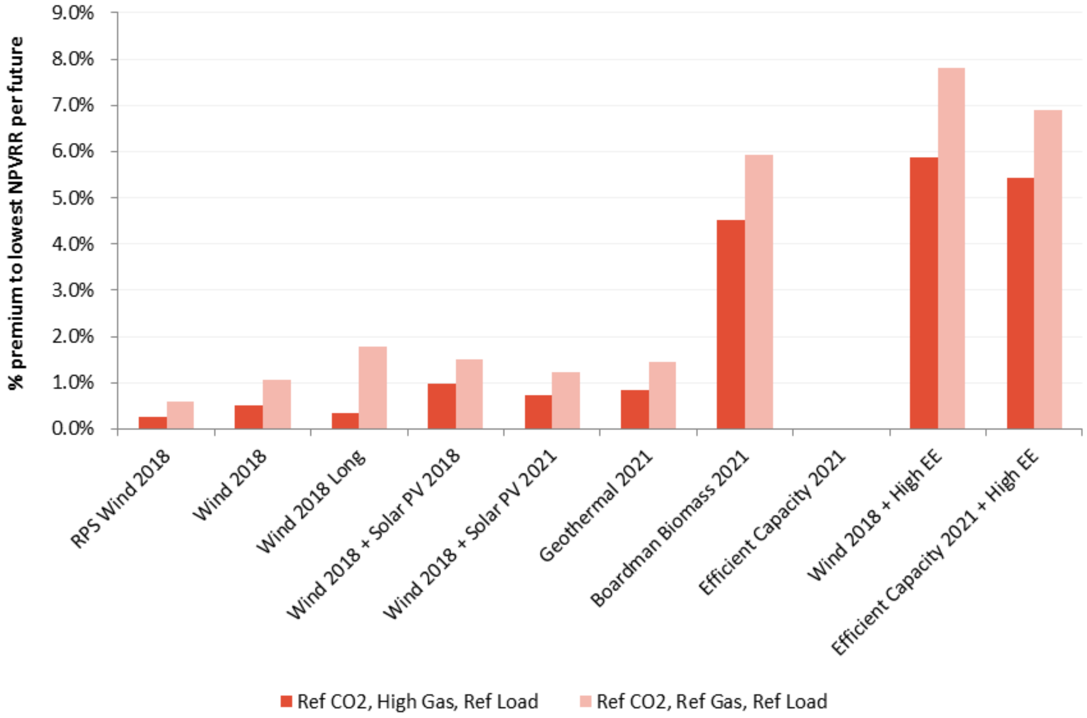
[214] Nuclear plants would be a zero emission resource but they are not an option for Oregon until completion of a Federal nuclear waste repository in the USA. Nor do any new nuclear plants have traction currently in an adjacent state. Therefore, PGE does not simulate nuclear energy additions in any of the portfolios in this IRP.

3. This sheltering from exposure to higher natural gas prices is apparent in portfolios that procure renewables beyond the RPS targets and/or pursue greater amounts of energy efficiency. In both instances, portfolios become more cost-competitive under the High Gas Price forecast.

FIGURE 12-10: Portfolio premium to lowest cost by natural gas future (reference case CO_2 / load)

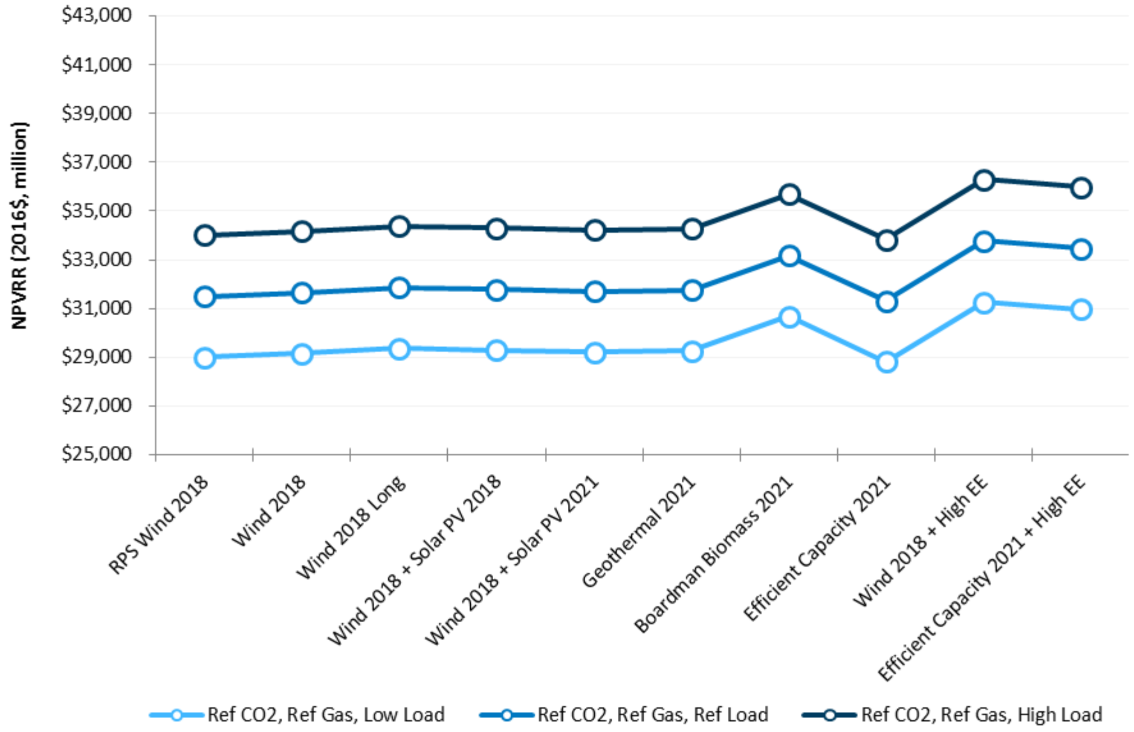


12.7 Load Growth Futures Analysis

The third major element of the futures analysis used in this IRP is portfolio load growth. In addition to the Reference Load forecast, high and low load growth futures are also simulated. The analysis provides insights into the potential impacts of fundamental shifts driven by the economy, population growth, changes in electric end uses (such as widespread adoption of electric vehicles or distributed solar PV).

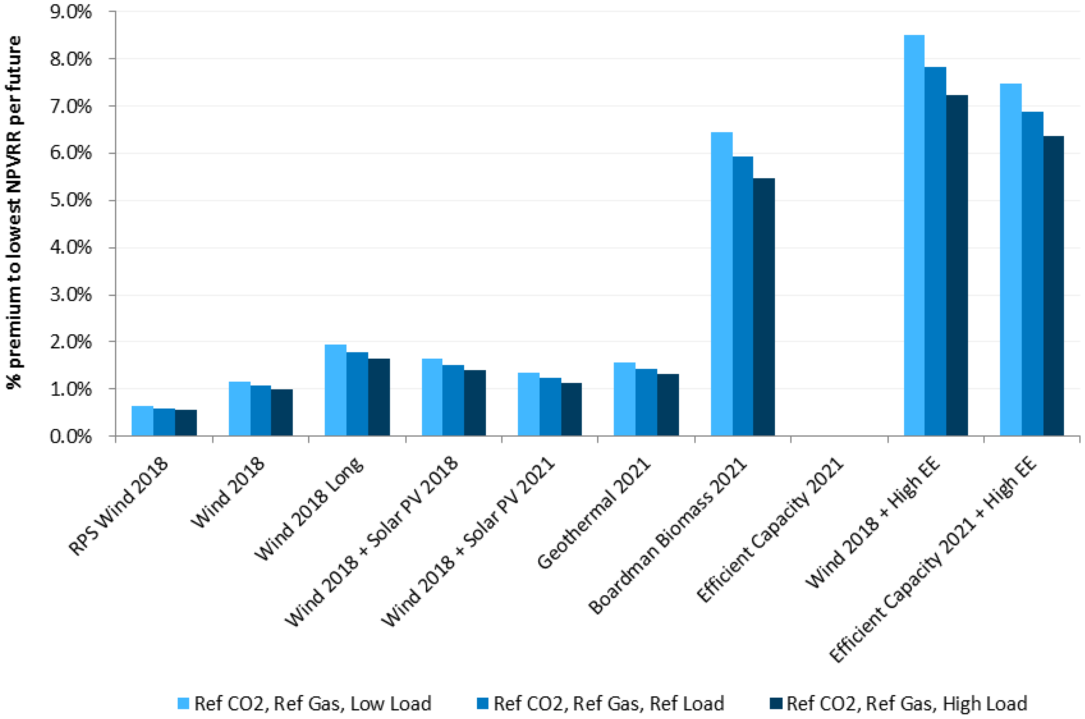
Figure 12-11 shows portfolio performance under the three PGE load growth futures with CO_2 and natural gas prices held constant at the Reference Case assumption. The treatment of load growth futures assumes that long-term resource procurement is established to meet Reference Load, and actual load either persistently under- or over-shoots this forecast. These variations in load similarly affect all portfolios, and all add the same amount of market purchases relative to the Reference Load assumption when load is systematically higher. When PGE load is lower than the Reference Load assumption, all portfolios' exposure to market purchases are reduced by the same relative amount. The resulting risk is the portfolio being long (surplus) relative to load, with commitments to longer-term resources when loads do not meet expectations. The converse is true when load growth exceeds expectations, the portfolio will be net short to load.

FIGURE 12-11: Portfolio performance by load future



For purposes of the analysis presented here, PGE holds the High EE quantity and cost constant across the futures. That is, under the Low Load future, PGE does not adjust the quantity of additional EE (incremental to the cost-effective forecast) downward. Nor is this amount adjusted upwards under the High Load future. This factor may explain somewhat outsized response of the two portfolios containing High EE to the High and Low Load futures as represented in Figure 12-12.

FIGURE 12-12: Portfolio premium to lowest cost by load future (reference case CO_2 / gas)



12.8 Application of Portfolio Scoring Metrics

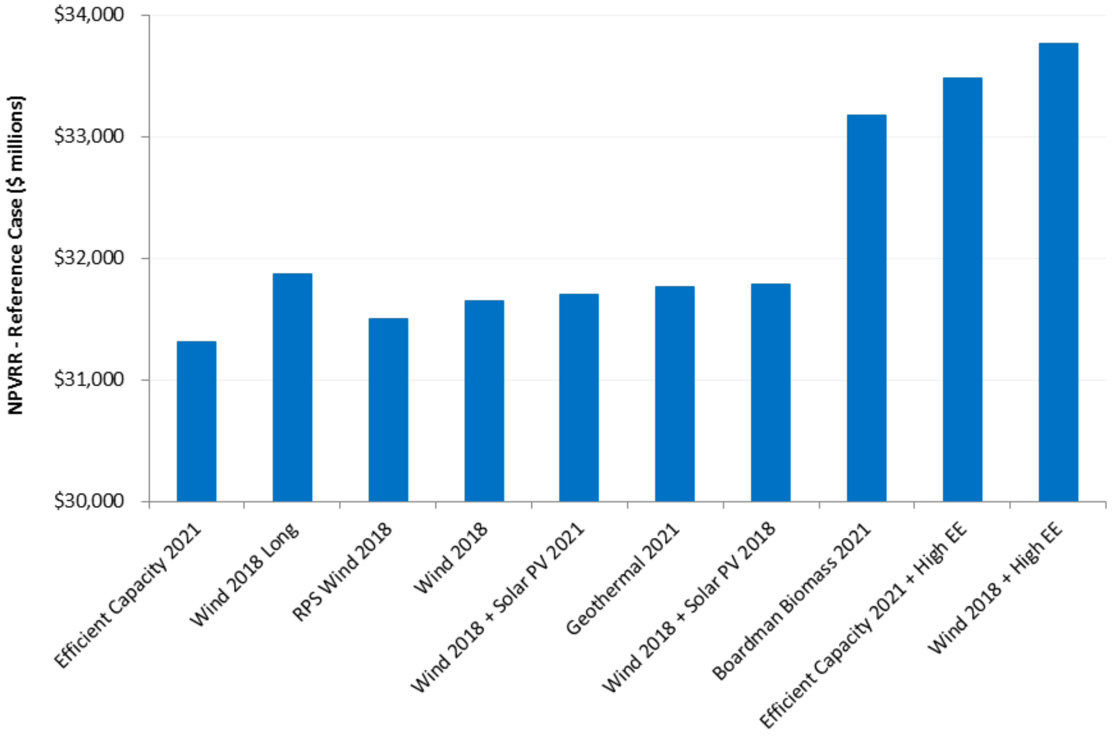
In the Integrated Resource Planning framework, portfolio analysis seeks to identify a portfolio of resources that provides the best combination of cost and risk. In doing so, the portfolio must consistently perform well across a diverse range of potential future environments. The combinations of these futures serve as a reasonable proxy for the types of uncertainty that may be encountered in the future. To assess the performance of each candidate portfolio, PGE calculates the NPVRR for each combination of incremental resources, in conjunction with the existing PGE resource portfolio, across the 23 potential futures described in Chapter 10, Modeling Methodology (see also Appendix L, Supplemental Findings Across Futures). Additionally, Chapter 11, Scoring Metrics, describes in detail the elements of portfolio scoring and analysis (how value is attributed to various portfolio performance characteristics). This section provides observations regarding portfolio scoring after generating simulated results for each portfolio under the conditions of each future. The output data for the ten portfolios considered for scoring and analysis are summarized below in a manner consistent with the factors discussed in Chapter 11, Scoring Metrics.

12.8.1 Portfolio Cost

PGE's assessment of portfolio performance begins with Reference Case costs shown in Figure 12-13. As described in Chapter 10, Modeling Methodology, the Reference Case represents PGE's expected future state for each of the input variables. The lowest cost portfolio considered in PGE's scoring, when considering only the reference case NPVRR, is *Efficient Capacity 2021*. *RPS Wind 2018* follows the *Efficient Capacity 2021* portfolio in Cost ranking, with *Wind 2018* and *Wind 2018 + Solar PV 2021* performing similarly on an expected cost basis (as represented by reference case assumptions).

Figure 12-13 summarizes the Reference Case cost results for each portfolio considered in scoring and analysis.

FIGURE 12-13: Portfolio cost



In line with the approach described in Chapter 11, Scoring Metrics, PGE ranks portfolios according to their performance under each metric, with the top-ranked portfolio then receiving 100 points and the bottom-ranked portfolio receiving zero points. Table 12-12 summarizes the scoring results for the Cost metric.

TABLE 12-12: Portfolio cost scoring

Rank	Portfolio Name	Cost	Score
1	Efficient Capacity 2021	31,319	100
2	RPS Wind 2018	31,504	92
3	Wind 2018	31,652	86
4	Wind 2018 + Solar PV 2021	31,705	84
5	Geothermal 2021	31,769	82
6	Wind 2018 + Solar PV 2018	31,792	81
7	Wind 2018 Long	31,875	77
8	Boardman Biomass 2021	33,173	24
9	Efficient Capacity 2021 + High EE	33,476	12
10	Wind 2018 + High EE	33,768	0

12.8.2 Portfolio Risk – Variability

When assessing portfolio risk, PGE evaluates the severity, variability, and risk durability. (Chapter 11, Scoring Metrics, discusses these risk measures in detail.) As discussed in Chapter 11, Scoring Metrics, PGE defines the variability metric is defined similarly to semivariance, measuring the dispersion of results that fall on a particular side of a specific outcome. For purposes of portfolio performance assessment, this metric captures the variability across the futures that are higher cost than the Reference Case for each portfolio. To illustrate the potential importance of this variance, portfolios that are dominated by spot market purchases may have low Reference Case expected costs, but may have exposure to extreme deviations in cost (from expectation) due to the potential for high-cost future environments. Conversely, portfolios dominated by fixed costs (e.g., wind) may have a higher reference case expected cost, but exhibit reduced variability in results in excess of the Reference Case because the portfolio cost structure is less subject to external/market influences. When looking at absolute cost exposure, the higher fixed-cost portfolios appear to be the most risky. When measuring risk based on the variability metric, however, the *Efficient Capacity 2021* portfolio appears the most risky followed by the portfolio containing only RPS compliance Wind and generic capacity (*RPS Wind 2018*). The portfolios exhibiting the best performance under the variability metric are *Wind 2018 Long*, *Wind 2018 + High EE*, and *Efficient Capacity 2021 + High EE*. Figure 12-14 presents the variability metric results for the portfolio scoring and analysis.

FIGURE 12-14: Portfolio risk – Variability

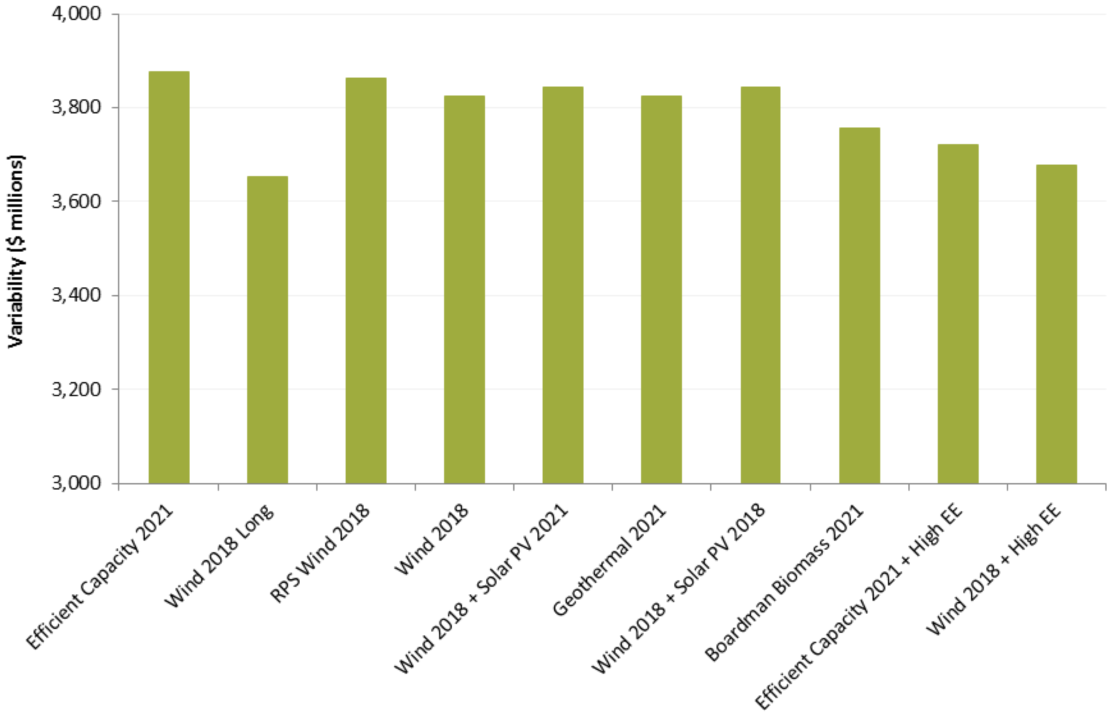


Table 12-13 summarizes the scoring results for the Variability metric.

TABLE 12-13: Portfolio Variability scoring

Rank	Portfolio Name	Variability	Score
1	Wind 2018 Long	3,654	100
2	Wind 2018 + High EE	3,678	89
3	Efficient Capacity 2021 + High EE	3,720	70
4	Boardman Biomass 2021	3,756	54
5	Wind 2018	3,823	24
6	Geothermal 2021	3,824	24
7	Wind 2018 + Solar PV 2018	3,843	15
8	Wind 2018 + Solar PV 2021	3,843	15
9	RPS Wind 2018	3,861	7
10	Efficient Capacity 2021	3,877	0

12.8.3 Portfolio Risk – Severity

PGE measures severity as the average of the **three** highest cost outcomes across all futures for a given portfolio. The Company selected the three highest cost outcomes as an approximation for the 90th percentile of cost outcomes. This metric focuses on the absolute magnitude of bad outcomes (without regard to the expected cost as defined by the Reference Case). Under this risk metric, the relative results for the portfolios remain generally consistent with the cost results under the Reference Case; that is, portfolios with lower Reference Case costs tend to have less severe outcomes under adverse conditions, and those with higher Reference Case costs tend to have more severe outcomes in challenging environments. With respect to the "severity" risk metric the top three performing portfolios are *Efficient Capacity 2021*, *Wind 2018 Long*, and *RPS Wind 2018*.

FIGURE 12-15: Portfolio risk – Severity

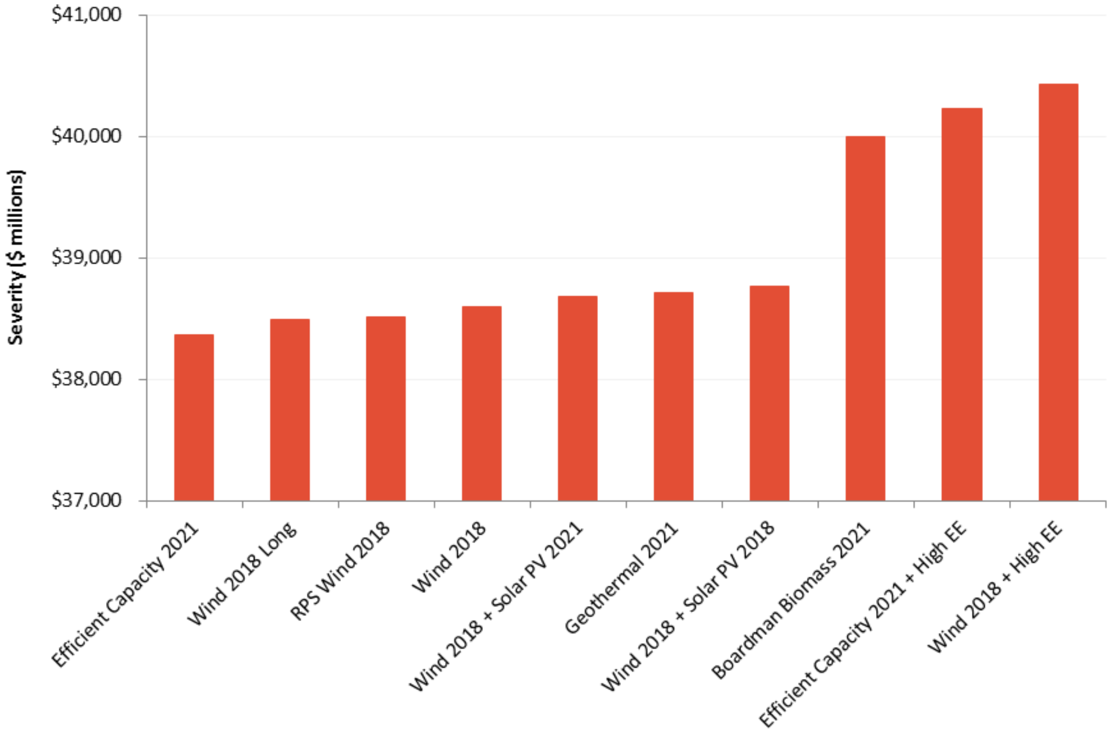


Table 12-14 summarizes the scoring results for the Severity metric.

TABLE 12-14: Portfolio Severity scoring

Rank	Portfolio Name	Severity	Score
1	Efficient Capacity 2021	38,369	100
2	Wind 2018 Long	38,492	94
3	RPS Wind 2018	38,509	93
4	Wind 2018	38,593	89
5	Wind 2018 + Solar PV 2021	38,682	85
6	Geothermal 2021	38,711	83
7	Wind 2018 + Solar PV 2018	38,769	81
8	Boardman Biomass 2021	39,999	21
9	Efficient Capacity 2021 + High EE	40,228	10
10	Wind 2018 + High EE	40,431	0

12.8.4 Portfolio Risk – Durability Across Futures

An approach to further distinguish the performance of candidate portfolios is to examine each portfolio's likelihood of being among the best or worst cost performers across all futures. This assessment provides insights about the risk durability of each portfolio. Top portfolios will more frequently outperform their peers under each future, while also less frequently performing poorly (as compared to other candidate portfolios). PGE calculates the likelihood of good or bad performance based on the percentage of futures in which a given portfolio ranks within the top-third of the Action Plan candidate, less the percentage of futures in which that same portfolio falls in the bottom-third. Figure 12-16 depicts this joint probability of achieving good performances while avoiding poor performances. This graph suggests that portfolios with lower expected costs under Reference Case conditions also generally perform well relative to other portfolios across most of the futures. *RPS Wind 2018*, *Efficient Capacity 2021*, and *Wind 2018* are portfolios that are more likely to be among the top performers under this risk durability performance assessment.

FIGURE 12-16: Portfolio risk – Durability across futures

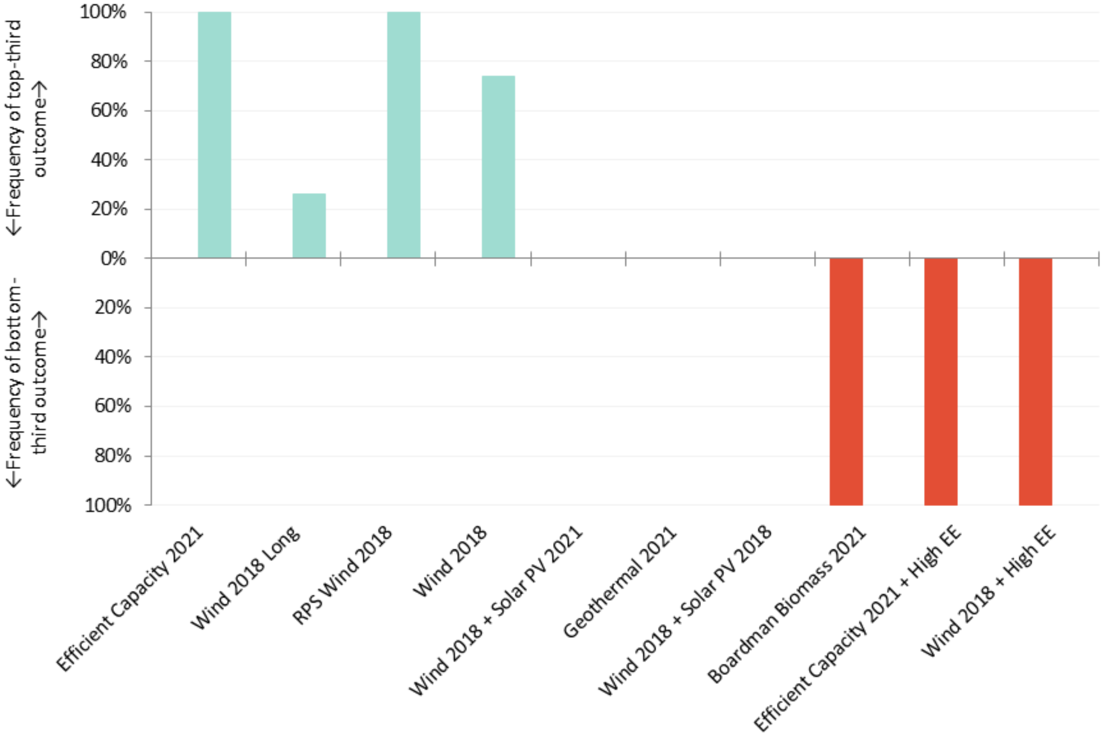


Table 12-15 summarizes the scoring results for the Durability Across Futures metric.

TABLE 12-15: Portfolio Durability Across Futures scoring

Rank	Portfolio Name	Durability	Score
1	RPS Wind 2018	100%	100
2	Efficient Capacity 2021	100%	100
3	Wind 2018	74%	87
4	Wind 2018 Long	26%	63
5	Wind 2018 + Solar PV 2021	0%	50
6	Geothermal 2021	0%	50
7	Wind 2018 + Solar PV 2018	0%	50
8	Efficient Capacity 2021 + High EE	(100%)	0
9	Wind 2018 + High EE	(100%)	0
10	Boardman Biomass 2021	(100%)	0

12.8.5 Reliability Considerations

As discussed in Chapter 10, Modeling Methodology, all of the resource portfolios subjected to the preceding analyses and included for consideration in the Action Plan are designed to achieve PGE's resource adequacy targets. PGE adds sufficient capacity across the analysis time horizon to achieve the minimum reliability threshold. For this reason, reliability is not explicitly included in the scoring framework.

12.8.6 Summary Observations

The scores for the Cost, Variability, Severity, and Durability Across Futures from above are summarized in Table 12-16, below. Weights are assigned to the various metrics, consistent with the approach outlined in Chapter 11, Scoring Metrics, and this total weighted score (reflected in the column "Weighted Score" in the table below) is then used to determine the portfolio final ranking. In addition to this portfolio scoring, PGE provides a supplemental view of cost and risk in Appendix L, Supplemental Findings Across Futures.

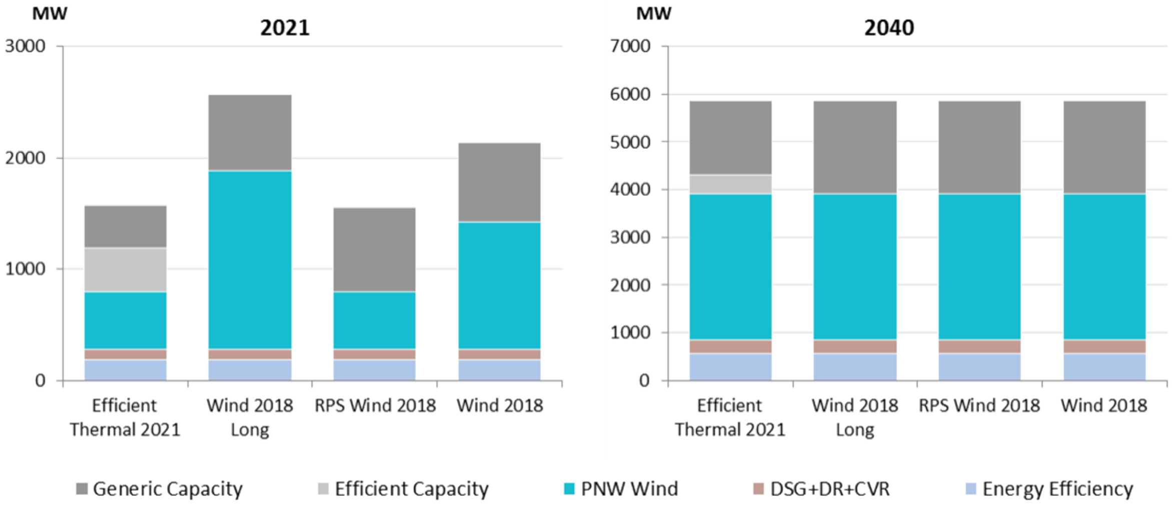
TABLE 12-16: Portfolio scoring summary

	Metric Weighting	50%	16.7%	16.7%	16.7%	
Rank	Portfolio Name	Cost Score	Severity Score	Variability Score	Durability Score	Weighted Score
1	Efficient Capacity 2021	100	100	0	100	83
2	Wind 2018 Long	77	94	100	63	81
3	RPS Wind 2018	92	93	7	100	80
4	Wind 2018	86	89	24	87	77
5	Wind 2018 + Solar PV 2021	84	85	15	50	67
6	Geothermal 2021	82	83	24	50	67
7	Wind 2018 + Solar PV 2018	80	81	15	50	65
8	Boardman Biomass 2021	24	21	54	0	25
9	Efficient Capacity 2021 + High EE	12	10	70	0	19
10	Wind 2018 + High EE	0	0	89	0	15

12.9 Preferred Portfolio

All resource portfolios considered for the Action Plan in this IRP contain sufficient incremental physical RPS-qualifying resources to maintain RPS compliance over the analysis time horizon, as well as the necessary capacity additions to achieve resource adequacy. Differences in portfolio composition are largely attributable to various types and quantities of incremental renewable resources in the near-term, and different technologies to achieve the capacity targets. However, over time, all portfolios must procure the same quantity of RPS resources and maintain resource adequacy. Figure 12-17 illustrates the composition of incremental resources in 2021 and 2040 of the top-four performing portfolios based on the scoring framework described previously.

FIGURE 12-17: Cumulative resource additions (MW) in top four portfolios, 2021 & 2040



Despite the relative diversity of composition in these resource portfolios at 2021, the analysis and scoring exercise in this IRP results in total weighted scores for the top-ranked portfolios that are very close to one another. With the primary goal of the IRP being the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers[215] , *Efficient Capacity 2021* is the Preferred Portfolio in this IRP. The resource composition of *Efficient Capacity 2021* is discussed in more detail in Chapter 10, Modeling Methodology, and Appendix O, Portfolio Detail.

The similarity of the results indicates that it is not appropriate to constrain the types or quantities of future resource procurement based solely on the results observed in this IRP. Rather, the results support a position favoring a procurement effort that enables the market to propose broad-ranging resources that achieve renewable goals and/or support resource adequacy.

While the IRP seeks to include all supply- and demand-side resources expected to be available during the Action Plan time horizon to satisfy portfolio needs, it is not possible to fully-represent in the IRP the mix of resources the market will offer. Additionally, the IRP analysis relies on informed, but generic, assumptions regarding the cost, availability, performance, and other parameters of the resources that are included. The specific characteristics of the incremental resources are crucial when making a procurement decision based on the relative performance of multiple options. Both the available resource mix and their associated parameters can be known with a high-level of certainty, when offers are solicited from the market.

Chapter 13, Action Plan, provides further discussion regarding the alignment of the Preferred Portfolio with the Action Plan.

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[215] OPUC Order No. 07-047.

CHAPTER 13. Action Plan

PGE's Action Plan flows from the selection of the Preferred Portfolio and combined scoring criteria that accounts for expected cost, deterministic and stochastic risk considerations, reliability, and diversity factors. The resulting Total Resource Portfolio integrates incremental resources with existing resources to balance overall cost and risk for PGE and its customers. The Action Plan, its emphasis on increasing levels energy efficiency, demand response, renewable resources, and allowing diversity of fuels and technologies provides a robust platform to respond to changes in policy, technology, reliability, and price uncertainties.

Chapter Highlights

- ★ **The Action Plan is comprised of the proposed set of resource actions PGE intends to undertake over the next four years, 2017 through 2020, to acquire the identified resources by 2021.**
- ★ **The Preferred Portfolio, *Efficient Capacity 2021*, represents the set of resources that provide the best combination of expected cost and risk for PGE and its customers under the assumptions used in the IRP process.**
- ★ **Demand-side resource acquisitions include Energy Efficiency, Demand Response, and Conservation Voltage Reduction. Supply-side resource acquisitions include a combination of Renewable, Capacity, and Standby resources.**
- ★ **PGE plans to pursue studies to evaluate wholesale market risk, the Western Energy Imbalance Market, Energy Storage, and customer preferences in the next IRP.**

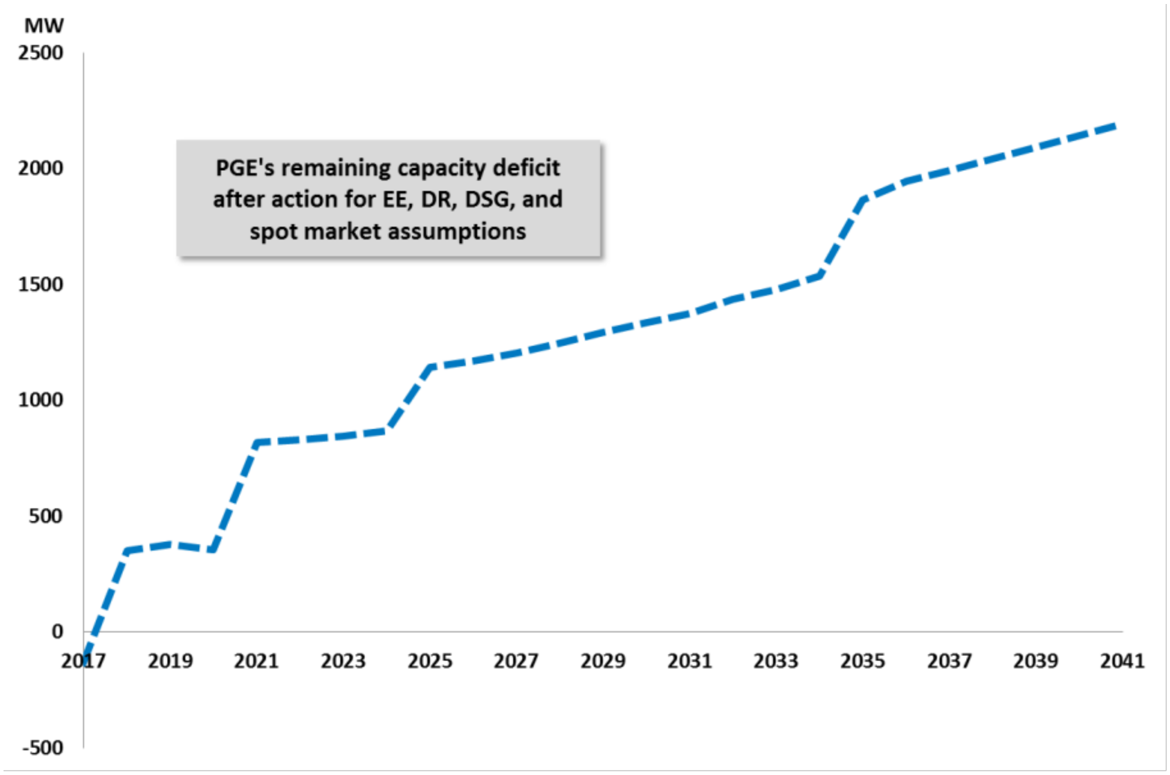
13.1 Action Plan and Preferred Portfolio Alignment

The IRP process results in the selection of a Preferred Portfolio which informs the long-term resource strategy of the Company. Development of a near-term resource Action Plan, aligned with the Preferred Portfolio, enables PGE to move forward in accordance with its strategic direction while maintaining the necessary flexibility to be responsive to changes in the planning environment.

The Company's near- and long-term strategies include further reducing carbon emissions and evolving the resource mix to meet Oregon's 50 percent renewable portfolio standard by 2040. PGE's IRP positions the Company to effectively adapt to a wide array of economic and environmental futures, while continuing to provide safe and reliable service for customers at a reasonable cost.

Many factors, including the cessation of coal-fired generation at the Boardman Plant, result in PGE's need for over 800 MW of capacity no later than 2021. As shown by Figure 13-1, PGE is facing an impending significant resource need.

FIGURE 13-1: Annual capacity need



The size of this shortfall creates a situation in which PGE cannot achieve resource adequacy through the acquisition of variable renewable resources alone. Therefore, every resource adequate portfolio evaluated in this IRP includes some form of dispatchable resource.

The Preferred Portfolio, *Efficient Capacity 2021*[216], represents the set of resources that provides the best combination of expected cost and risk for PGE and its customers under the assumptions used in the IRP process.

TABLE 13-1: Preferred portfolio cumulative resources

Preferred Portfolio Cumulative Resources* *Efficient Capacity 2021* (Nameplate Capacity, MW)	**Action Plan Time Horizon** 2017	2018	2019	2020	2021
Energy Efficiency (EE)	45	89	131	168	202
Demand Response (DR)	26	29	32	70	78
Conservation Voltage Reduction (CVR)	-	0.43	0.86	1.29	1.74
PNW Wind	-	515	515	515	515
Generic Capacity	-	290	317	317	370
Efficient Capacity	-	-	-	-	389
Dispatchable Standby Generation (DSG)	4	8	12	16	20

*The resource composition of the Preferred Portfolio, *Efficient Capacity 2021*, is discussed in more detail in Chapter 10, Modeling Methodology, and Appendix O, Portfolio Detail.

It is important to remember that the implementation of any plan is subject to uncertainty and the Preferred Portfolio is not a fixed course of action. In fact, as noted in Chapter 12, Modeling Results, the top-ranked portfolios are relatively comparable in terms of performance. Additionally, the precise resources and prices modeled in the portfolios will not be the exact resources and prices available in the market.

For example, the top-ranked portfolio – *Efficient Capacity 2021* – includes the addition of 515 MW of "PNW Wind" renewable resources in 2018. The discussion of renewable resources in Chapter 7, Supply Options, details the assumed characteristics of a PNW Wind resource sited in the Oregon region with an average wind speed at the 80-meter hub height of 6.6 meters per second, with an estimated capacity factor of 34 percent, and technology modeled by GE 2.0-116 turbines. This does not mean that a resource acquisition will be limited to only this specific location, technology type, or timing. In fact, the acquisition process will encourage proposals from diverse locations (Oregon, Washington, Idaho, Montana, etc.), and from all RPS compliant resources (wind, solar, geothermal, biomass, incremental hydro, etc.). Resources can be new or existing, physical or REC-based, PGE-owned or contracted. PGE will require each proposal to describe its key attributes and how it meets the needs identified by the IRP.

A similar alignment between the Preferred Portfolio and the Action Plan should be used when considering the resources used to meet the identified capacity need. The two top-ranked portfolios – *Efficient Capacity 2021* and *RPS Wind 2018* – have identical resource additions in terms of nameplate capacity. Both include the addition of 515 MW of renewable resources in 2018, as well as demand-side actions common to all portfolios. The difference arises in the technology composition

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[216] The resource composition of the Preferred Portfolio, *Efficient Capacity 2021*, is discussed in more detail in Chapter 10, Modeling Methodology, and Appendix O, Portfolio Detail.

of the dispatchable resources modeled. Specifically, the *Efficient Capacity 2021* Portfolio replaces 389 MW of the generic capacity resource (modeled as a frame F-class combustion turbine) with 389 MW of an efficient capacity resource (a combined-cycle combustion turbine (CCCT) modeled as an H-class machine), resulting in a relatively lower emission profile. The relative similarity in scores between these two portfolios suggests that differentiation between various thermal resource technologies and capacity contracts will depend on the costs of specific resource options available for procurement, which may differ from the assumptions employed in the IRP. As with RPS compliant resources, the modeled capacity resources do not preclude proposals for other technologies to meet the identified need.

PGE evaluates capacity contributions from all resources using the Effective Load Carrying Contribution methodology described in Chapter 5, Resource Adequacy. Additionally, the in-depth flexible capacity analysis suggests that a strategy allowing optionality in technology selection provides the best opportunity for diverse resource options to be proposed to meet PGE's needs by 2021. Thus, the recommended Action Plan targets acquisition of available resources that maintain resource adequacy and align with the key attributes identified in portfolio evaluation, but does not limit resources to the exact parameters of the Preferred Portfolio.

13.2 Recommended Action Plan

The Action Plan is comprised of the proposed set of resource actions PGE intends to undertake over the next two to four years, i.e., 2017 through 2020[217], to acquire the identified resources[218] by 2021. Implementation of the Action Plan will:

- Increase PGE and customer use of cost-effective demand-side resources including energy efficiency.
- Pursue acquisition of incremental renewable and efficient, flexible, and dispatchable resources to comply with policy, maintain resource adequacy, and deliver benefits to customers.
- Preserve existing competitive generating resources while managing emissions.
- Reduce reliance on coal-fired generation and support PGE's de-carbonization efforts.

To accomplish these goals and acquire resources aligned with the Preferred Portfolio, PGE describes three categories of resource action: demand-side, supply-side, and integration. To inform the next IRP or IRP Update, PGE also suggests Enabling Studies in the Action Plan. PGE shared its draft Action Plan with stakeholders at its August 17, 2016, IRP public meeting, and received useful feedback, which the Company considered to further develop and describe its intended actions.

Demand-side Actions

a. **Energy Efficiency.** PGE supports the cost-effective deployment of EE, targeting the addition of 135 MWa (176 MW)[219]. PGE continues to work collaboratively with the Energy Trust of

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[217] Resource acquisition is a multiyear process, thus actions occur in the 2017 through 2020 time horizon to acquire resources needed by 2021.

[218] OPUC Order No. 07-047.

[219] Gross value at busbar.

Oregon (Energy Trust) to assure sufficient funding for acquisition of all cost-effective EE, subject to consumer adoption constraints. Actions taken through the action plan window will support continued cost-effective acquisitions beyond 2020.

b. **Demand Response.** PGE will pursue Demand Response (DR) targeting the aggregate capacity addition of 77 MW (winter) and 69 MW (summer).

c. **Conservation Voltage Reduction.** PGE supports the cost-effective deployment of Conservation Voltage Reduction (CVR), and will pursue programmatic CVR installations to realize a minimum energy savings of 1 MWa through 2020. The following strategic initiatives are necessary to support the programmatic deployment of CVR.

   i. **Advanced Metering Infrastructure (AMI) Voltage Data Bandwidth Expansion.** PGE will expand its current AMI structure to enhance its ability to retrieve customer voltage data at the meter base at regular and frequent intervals.

   ii. **Data analytics research and development.** PGE will continue to research and develop data analytics software and tools that will allow the Company to provide an interactive user interface where engineers can efficiently monitor and evaluate voltage data and set an alarm for those meter voltages that travel outside the acceptable voltage bandwidth.

   iii. **Dynamic CVR Expansion.** PGE will expand its current dynamic CVR program in order to complete a system-wide implementation of CVR.

See Chapter 6, Demand Options, for additional discussion on EE, DR, and CVR.

Supply-side Actions

a. **Renewable Resources.** PGE intends to issue one or more Requests for Proposals for approximately 175 MWa of bundled RPS compliant renewable resources, and/or unbundled Renewable Energy Certificates (REC), with a preference for maximizing available incentives for the benefit of customers.

b. **Capacity Resources.** PGE's capacity need in 2021, after actions for EE, DR, CVR, DSG, and accounting for imports and executed but not yet online Qualifying Facility (QF) contracts[220], is approximately 819 MW.[221]

   PGE will issue one or more RFPs to acquire up to 850 MW of capacity. PGE will consider a mix of annual and seasonal resources. PGE may also enter into short and/or mid-term contracts (e.g., 2-5 years) to maintain resource adequacy between the time the capacity is needed and the time in which resources can be acquired through an RFP. Of the up to 850 MW, and in alignment with the Preferred Portfolio, PGE proposes pursuing acquisition of 375 to 550 MW

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[220] Some Qualifying Facilities are in early stage development and are at increased risk for delay or cancellation. PGE's capacity need will be greater if QF's under contract fail to come on line as planned.

[221] Annual capacity value.

of long-term annual dispatchable resources and up to 400 MW[222] of annual (or seasonal equivalent) capacity resources.

c. **Standby Resources.** PGE will pursue expansion of Dispatchable Standby Generation (DSG) by 16 MW to meet standby capacity needs (non-spin). PGE will also pursue actions (such as customer site development and contract negotiation) to achieve additional annual standby targets, if needed beyond 2020. See Chapter 6, Demand Options, for additional discussion on DSG.

d. **Hydro Contract Renewals.** PGE will continue to seek renewal, or partial renewal, of expiring legacy hydro contracts, to the extent the Company can renew these contracts cost-effectively for customers.

e. **Energy Resources.** PGE will assess the energy value brought by RPS or capacity resources through the RFP process and capture the merits of high capacity factor resources and result in reduced market exposure for PGE's customers.

Integration Actions

a. **Energy Storage.** Pursuant to House Bill (HB) 2193, and not later than January 1, 2018, PGE will submit one or more proposals to the Commission for developing a project that includes one or more energy storage systems that have the capacity to store at least five megawatt hours of energy.

Enabling Studies. Enabling studies are a list of potential research actions to inform the next IRP. PGE will work with stakeholders to develop appropriate scopes of study for research focused on:

- Ongoing analysis of market capacity;
- Continued flexibility and curtailment evaluation; and
- Customer insights.

13.3 Resource Acquisition

PGE will acquire the resources identified in the IRP through a combination of actions related to both existing and new resources. For new, incremental resources, PGE will ensure that solicitations, or RFPs, are designed so that the portfolio effects between incremental resources can be determined.

As discussed above, the similarity of the results across portfolios indicates it is not appropriate to constrain the types or quantities of future resource procurement to the exact resources modeled in the Preferred Portfolio. Rather, the portfolio analysis results support a procurement effort that enables the market to propose a broad range of resources that, in combination, can support long-term resource adequacy. The specific characteristics of the incremental resources are important when making a procurement decision because of the relative performance of multiple options. Equally important, is the interaction of the incremental resources with the balance of the portfolio.

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[222] Quantity subject to change based on incremental acquisitions: renewable acquisitions, contract execution, etc. Seasonal capacity products have capacity contribution values of less than 100 percent. For example, a contract for 300 MW of summer and winter capacity (July-September, December-February, On-peak hours) is equivalent to approximately 240 MW of an annual resource. See Chapter 5, Resource Adequacy, for additional discussion.

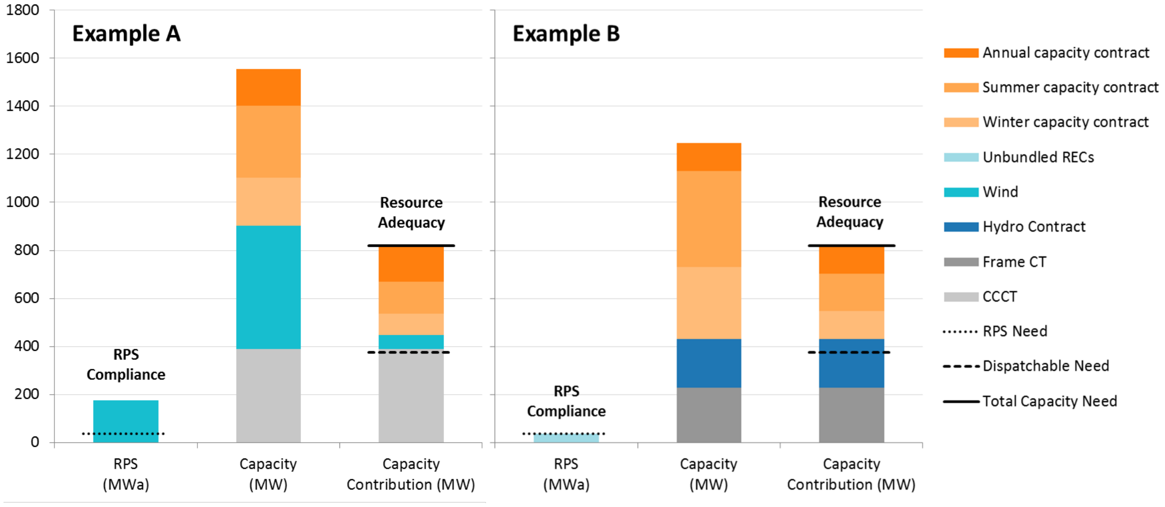
Chapter 5, Resource Adequacy, discusses incremental resource interactions with the total portfolio in more detail.

Figure 13-2 depicts two illustrative portfolios that are consistent with the Action Plan.

- **Example A.** Illustrates a portfolio that is consistent with the resource additions in the *Efficient Capacity 2021* portfolio, but fills some portion of the capacity need with annual and seasonal contracts. The RPS resources under consideration exceed the incremental RPS need, but the PTC eligibility of the wind resource provides sufficient cost savings to justify consideration of early procurement of wind to meet future RPS obligations, as is explored in Chapter 7, Supply Options. The renewable resources in this portfolio also contribute to meeting the capacity need based on their ELCC. The remaining capacity need is met through procurement of an efficient and flexible CCCT to satisfy the dispatchability requirement and by securing annual and seasonal capacity contracts.
- **Example B.** Illustrates a portfolio that meets the RPS obligation in 2021 with a contract for unbundled RECs, which provide no capacity contribution. The capacity need in this portfolio is met through procurement of a frame CT and a hydro contract with firm dispatchable capacity across the year to satisfy the dispatchability requirement as well as a combination of seasonal and annual capacity products.

Both examples demonstrate resource options which result in resource adequacy, are consistent with the Action Plan, and are potentially procurable through an RFP. Note that different resource types can back annual and seasonal contracts, provided the capacity contribution, in combination with the balance of the portfolio, meets resource adequacy requirements.

FIGURE 13-2: Illustrative portfolios consistent with the action plan



Consistent with the IRP portfolio analysis, PGE's economic comparison between these two portfolios will depend on: the cost of each resource option; the price of each contract; and the total cost impact of operating each resource within the PGE system over its economic lifetime, including the impacts of market exposure and any differential in the capacity and RPS procurement needed in later years as a result of the resource acquisition. The analytical framework applied in portfolio analysis provides a means for comparing across each of these factors to determine the portfolio option that best balances cost and risk once pricing information is available.

13.4 Benchmark Resources

The Commission’s IRP Guidelines require PGE to identify any site-specific, self-build proposals (Benchmark Resources) it plans to consider in competitive bidding. At this time, PGE does not plan to submit Benchmark Resources at PGE's existing Carty Generating Station site in any RFP that it conducts to acquire capacity resources. PGE is currently exploring renewable resource and energy storage options that could be considered as Benchmark Resources in RFPs.

13.4.1 Preliminary Resource Considerations

With an eye on the ability to serve customers into the future, PGE is seeking permits for potential new generating resources adjacent to Boardman and Carty. Permitting is one of the first steps in the lengthy development process and is required before proposals for new generating resources can be fully identified and considered for acquisition. PGE is also performing initial due diligence to explore options for renewable and energy storage facilities.

13.4.1.1 Carty Unit 2

PGE is performing due diligence for the potential acquisition of a dispatchable resource with a nominal generating capability between 390-530 MW to be located at PGE′s existing Carty Generating Station site. The capacity resource could be a state-of-the-art, highly efficient and flexible plant consisting of a one-on-one (1x1) combined cycle combustion turbine using large frame advanced class (F, G, H, or J) models. PGE is not currently considering the development of Benchmark Resources at the site; however if viable, PGE may offer the site and technical specifications to potential bidders in an RFP as a PGE ownership option.

13.4.1.2 Carty Unit 3

PGE is performing due diligence for the potential acquisition of a dispatchable resource with a nominal generating capability between 225-330 MW to be located near PGE′s existing Carty Generating Station site. The capacity resource could be a state-of-the-art, highly efficient and flexible plant consisting of one simple cycle combustion turbine using large frame advanced class (F, G, H, or J) models. PGE is not currently considering the development of Benchmark Resources at the site; however, if viable, PGE may offer the site and technical specifications to potential bidders in an RFP as a PGE ownership option.

13.4.1.3 Renewable Resource

PGE is currently exploring renewable resource options that the Company could consider as Benchmark Resources in an RFP.

13.4.1.4 Energy Storage

PGE is currently exploring battery energy storage resource options that the Company could consider as Benchmark Resources in an FRP. Locations under consideration are within PGE′s existing service territory.

APPENDIX A. Compliance with the Commission's IRP Guidelines

Guideline 1	Substantive Requirements	PGE Compliance	Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.		
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation and storage – and demand-side options which focus on conservation and demand response.	Consistent with Order 07-002, PGE considers known supply-side and demand-side resources that the Company expects to become available. These resources include energy efficiency (EE), demand response (DR), dispatchable standby generation (DSG), central-station solar, wind, geothermal, biomass, and natural gas facilities. PGE simulated the behavior of an energy storage system operating within the PGE resource portfolio and looks forward to expanding on this framework in future IRPs.	Chapter 10, Modeling Methodology
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	PGE developed portfolios with the characteristics identified in the guideline. See the portfolio composition tables in Appendix O, Portfolio Detail.	Appendix O, Portfolio Detail
	Consistent assumptions and methods should be used for evaluation of all resources.	PGE evaluated all resources using a common set of assumptions, and analytical and modeling approach.	Chapter 10, Modeling Methodology
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PGE applied its after-tax marginal weighted-average cost of capital of 6.42 percent as a proxy for the long-term cost of capital in the WECC.	Chapter 10, Modeling Methodology

Guideline 1	Substantive Requirements	PGE Compliance	Chapter
Guideline 1b	Risk and uncertainty must be considered.		
	At a minimum, utilities should address the following sources of risk and uncertainty:		
	1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices and costs to comply with any regulation of greenhouse gas emissions.	PGE analyzes the variables specified in this guideline through a combination of 23 futures for the economic scenario analysis. The Company uses stochastic modeling in the reliability studies and simulates the volatile behavior for weather impact to loads, water years, wind intermittency and plant forced outages with mean times to repair. For greenhouse gas, PGE has simulated futures with various CO_2 tax levels including one provided by Synapse Energy. In addition, scenario analysis considered futures with the Clean Power Plan active and inactive.	Chapter 10, Modeling Methodology
	2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A to PGE	N/A
	Utilities should identify in their plans any additional sources of risk and uncertainty.	PGE identified load, carbon price, and gas price as the three main sources of risk and uncertainty. Additionally, PGE identified other risks and uncertainties including capital cost (higher or lower than projected for both thermal and renewables plants), differing assumed lives for wind plants, earlier discontinuation of the PTC and ITC, and plant availability (for wind). PGE evaluated these risks by designing multiple futures that stress these variables. The Company created scenarios that combine risk factors (e.g., high carbon costs and high natural gas prices) in order to measure the combined impact on cost and wholesale electricity prices.	Chapter 10, Modeling Methodology
Guideline 1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its	The IRP Action Plan allows PGE to continue to serve its customers with a portfolio of resources that provides the	Chapter 11, Scoring Metrics

Guideline 1	Substantive Requirements	PGE Compliance	Chapter
	customers.	best combination of expected costs and associated risks and uncertainties. PGE captures the costs and risks of candidate portfolios through four metrics: cost, variability, severity, and durability across futures. The Company weights portfolio performance across these metrics employing a 50/50 weighting of cost versus the combined risk metrics to identify portfolios that perform well with respect to both cost and risk.	Chapter 12, Modeling Results Appendix L, Supplemental Findings Across Futures
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PGE calculated the fixed and variable costs of portfolios from 2017 through 2050. PGE accounted for end effects by levelizing the costs (recovery of life-cycle resource investment and fixed costs, including estimated decommissioning) of resources procured within the planning horizon and anticipated to serve PGE customers after 2050. PGE's recommendations in this IRP focus on the Action Plan time horizon (through 2020). In order to reflect the effects of these near-term decisions on the need to maintain resource adequacy and RPS compliance in the future, PGE includes resource additions across the analysis time period (through 2050). PGE uses levelized fixed costs to capture resources' life-cycle costs.	Chapter 10, Modeling Methodology
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PGE uses expected NPVRR. The Company includes all other costs over time for gas transport, transmission, fuel, fixed cost recovery, etc. within the revenue requirement modeling for all long-lived and short-lived resources. That is, PGE includes all costs the Company would actually incur to operate the resource. Input assumptions for these costs come from Black & Veatch, DNV-GL, Wood Mackenzie, Energy Information Administration, existing contract costs,	Chapter 10, Modeling Methodology

Guideline 1	Substantive Requirements	PGE Compliance	Chapter
		and other industry sources.	
	To address risk, the plan should include, at a minimum:		
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PGE measures the variability of costs by applying the semi-variance metric to portfolios' NPVRR results across futures. By averaging the three worst-case outcomes for each portfolio, PGE was able to assess the severity of outcomes. PGE also considers relative likelihood of high or low expected cost.	Chapter 11, Scoring Metrics
	2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	PGE includes a discussion of traditional physical and financial hedging approaches for wholesale electricity and for natural gas, including their purpose and limitations.	Chapter 3, Planning Environment
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	PGE's description of its modeling results in Chapter 12, Modeling Results, describes how each portfolio balances cost and risk. PGE's Preferred Portfolio, which forms the basis of the Action Plan, performs better than other alternatives under a wide range of potential future circumstances. This relative performance indicates how the Company appropriately balances cost and risk. PGE structured the Action Plan to provide the opportunity to acquire resources aligning with the balance cost/risk evaluation.	Chapter 12, Modeling Results Chapter 13, Action Plan
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PGE models a portfolio to achieve the following: Oregon CO_2 goals, RPS compliance in all portfolios, current regulatory requirements for non-CO_2 and CO_2 environmental compliance in all portfolios, and various scenarios for future federal regulation of CO_2 under the Clean Power Plan.	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail

Guideline 2	Procedural Requirements	PGE Compliance	Chapter
Guideline 2a	The public, which includes other utilities, should be	The public, as represented primarily by a number of	Chapter 2, IRP Public Process

Guideline 2	Procedural Requirements	PGE Compliance	Chapter
	allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	stakeholder organizations, played a significant role in the development of PGE's 2016 IRP. PGE hosted several public meetings to discuss and solicit input on its modeling methodologies and the results of the numerous analyses conducted during development of this plan. The Company shared the results of its research, analysis, and findings with external stakeholders at each public meeting.	Appendix C, Public Process Agendas
Guideline 2b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE's IRP provides non-confidential information used for portfolio evaluation and development of the action plan.	N/A
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE distributed a draft IRP for public review on September 26, 2016, and accepted comments from stakeholders through October 26, 2016.	N/A

Guideline 3	Plan Filing, Review and Updates	PGE Compliance	Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	PGE filed its last IRP on March 27, 2014. The Commission issued Order No. 14-415 on December 2, 2014, acknowledging PGE's 2013 IRP. PGE filed its final 2016 IRP on November 15, 2016.	N/A
Guideline 3b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PGE will comply with this Guideline.	N/A
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP	N/A to PGE	N/A

Guideline 3	Plan Filing, Review and Updates	PGE Compliance	Chapter
	filing.		
Guideline 3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	N/A to PGE	N/A
Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A to PGE	N/A
Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	On December 2, 2015, PGE filed an annual update to the 2013 IRP (acknowledged on December 2, 2014) and presented a summary of the update at a Commission public meeting on January 12, 2016.	N/A
Guideline 3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:	N/A at this time	N/A
	Describes what actions the utility has taken to implement the plan;	N/A at this time	N/A
	Describes what actions the utility has taken to implement the plan;	N/A at this time	N/A
	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission	N/A at this time	N/A

Guideline 3	Plan Filing, Review and Updates	PGE Compliance	Chapter
	availability; and		
	Justifies any deviations from the acknowledged action plan.	N/A at this time	N/A

Guideline 4	Plan Components	PGE Compliance	Chapter
	At a minimum, the plan must include the following elements:		
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table is to show compliance with this Guideline. PGE includes more detailed descriptions and explanations of compliance with Commission requirements in the body of the 2016 IRP.	Appendix A, Compliance with the Commission's IRP Guidelines
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	PGE includes analysis of its high and low load growth scenarios. The Company also analyzes stochastic load risk, which is primarily the result of weather variations based on historical observations of pre-schedule vs. actual loads. PGE also uses stochastic load risk for the estimate of the reliability of the different portfolios tested in the 2016 IRP.	Chapter 10, Modeling Methodology
Guideline 4c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;	PGE performs three related analyses: 1) a capacity need assessment based on a reliability model which captures peaking capabilities of resources; 2) a flexible capacity need study; and 3) an energy load-resource balance calculation. All portfolios incorporate transmission costs, including those unique to each portfolio, with the exception of portfolios that include Montana Wind.	Chapter 4, Resource Need Chapter 5, Resource Adequacy Chapter 10, Modeling Methodology
Guideline 4d	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas	N/A to PGE	N/A

Guideline 4	Plan Components	PGE Compliance	Chapter
	supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;		
Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;	PGE develops resource-specific life-cycle revenue requirements and engaged the expertise of external consultants, Black & Veatch and DNV GL, to estimate costs and advances in technology. The estimates from the third-party consultants include outlooks on technology maturity and the potential for reductions in future capital costs.	Chapter 7, Supply Options
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	PGE's Action Plan seeks to acquire sufficient capacity to achieve the annual reliability target. The Company designed all portfolios, except *Portfolio 1*, to meet the required capacity need through a variety of resource additions. PGE examines the cost/risk tradeoffs of the different resource additions through scenario analysis.	Chapter 5, Resource Adequacy Chapter 12, Modeling Results
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	PGE based natural gas prices and CO_2 price on current Wood Mackenzie outlooks, and included a range of higher and lower cost outcomes. The most recent forecast update available for use in the IRP analysis was issued in the fourth quarter of 2015.	Chapter 3, Planning Environment
Guideline 4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;	PGE used a combination of predominantly single incremental resource and diversified portfolios, which acquire resources in various combinations with varying timing and durations as specified. The portfolios inherently include the considerations described in Guideline 4h.	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	PGE estimated the expected portfolio cost and a variety of scenario risks, along with reliability and diversity considerations.	Chapter 12, Modeling Results
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	PGE ranks portfolios according to their performance under each scoring metric with the top-ranked Portfolio	Chapter 12, Modeling Results

Guideline 4	Plan Components	PGE Compliance	Chapter
		receiving 100 points and the bottom-ranked Portfolio receiving zero points.	
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Portfolio analysis—in the IRP framework—seeks to identify a portfolio of resources that provides the best combination of cost and risk. In doing so, the portfolio must consistently perform well across a diverse range of potential future environments. The combinations of these futures serve as a reasonable proxy for the types of uncertainty that may potentially present in the future.	Chapter 12, Modeling Results
Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	The portfolio analysis and scoring exercise in this IRP results in total weighted scores for the top-ranked portfolios that are very close to one another. Selection of a Preferred Portfolio is necessary, thus, *Efficient Capacity 2021* is the Preferred Portfolio in this IRP.	Chapter 12, Modeling Results
Guideline 4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation;	All resource portfolios considered for the Action Plan in this IRP contain sufficient incremental physical RPS-qualifying resources to maintain RPS compliance, as well as capacity additions needed to achieve resource adequacy. To the best of PGE's knowledge, the Preferred Portfolio is consistent with existing federal and state energy policies.	Chapter 12, Modeling Results
Guideline 4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	PGE's Action Plan includes activities that the Company intends to undertake or commit to in the next two to four years. PGE describes three categories of action: demand-side, supply-side, and integration. PGE also includes enabling studies in the Action Plan, which will help to inform the next IRP or IRP Update.	Chapter 13, Action Plan

Guideline 5	Transmission	PGE Compliance	Chapter
	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for	Portfolio analysis includes costs for the fuel transportation and electric transmission required for each resource PGE	Chapter 7, Supply Options

Guideline 5	Transmission	PGE Compliance	Chapter
	each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	considers in its analysis. PGE bases Pacific Northwest (PNW) natural gas transport costs on current rates, with escalation at inflation going forward. PGE also uses BPA's published transmission tariff rates as of Q1 2016 (with escalation) for all new generating resources within the PNW. PGE also evaluates future transmission planning considerations.	Chapter 9, Transmission Options Chapter 10, Modeling Methodology

Guideline 6	Conservation	PGE Compliance	Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PGE worked closely with the Energy Trust of Oregon (Energy Trust) to develop the EE forecast. Specifically, PGE provided information to the Energy Trust, which included load growth assumptions based on PGE's load forecast as of February 2015, cost of capital, and avoided cost inputs. For this IRP, the Energy Trust developed two different projections: All Achievable EE and Cost-Effective EE. Cost-Effective EE is the amount the Energy Trust expects to acquire in the next 20 years. All Achievable EE includes all measures that do not have market barriers and are technically feasible.	Chapter 6, Demand Options
Guideline 6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Since 2002, the Energy Trust has been the independent, non-profit organization in charge of identifying the State's EE potential. PGE and other utilities fund such programs and work with the Energy Trust to implement EE measures. PGE maintains a long-term, productive relationship with the Energy Trust to ensure that EE remains a top priority resource for the Company and the State.	Chapter 6, Demand Options
Guideline 6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the		

Guideline 6	Conservation	PGE Compliance	Chapter
	utility should:		
	Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	The portfolios incorporate the results of the energy efficiency studies conducted by the Energy Trust which determine the amount of potential energy efficiency without regard to any funding limits, with the exception of the SB 838 funding constraints.	Chapter 6, Demand Options
	Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	PGE's Preferred Portfolio and Action Plan are consistent with the Energy Trust's projection of cost-effective EE potential. PGE continues to work collaboratively with the Energy Trust to assure sufficient funding for acquisition of all cost-effective EE, subject to consumer adoption constraints. PGE supports the cost-effective deployment of EE, targeting the addition of 135 MWa (176 MW) from 2017 through the end of 2020.	Chapter 6, Demand Options Chapter 12, Modeling Results Chapter 13, Action Plan

Guideline 7	Demand Response	PGE Compliance	Chapter
	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	To better inform DR initiatives and to establish inputs to its IRP process, PGE contracted with The Brattle Group to develop an updated DR potential study. The purpose of this study was to estimate the maximum system peak demand reduction capability that PGE could realistically achieve through the deployment of specific DR programs in its service territory under reasonable expectations about future market conditions. The study also assessed the likely cost-effectiveness of these programs. Using the values from the DR potential study, PGE developed portfolios of DR programs for consideration over the planning horizon. PGE evaluated demand response resources, including voluntary rate programs, on par with other options for meeting energy and capacity needs.	Chapter 6, Demand Options Chapter 10, Modeling Methodology

Guideline 8 (Order 08-339)	Environmental Costs	PGE Compliance	Chapter
Guideline 8a	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	PGE constructs a reference case based on third-party (Wood Mackenzie) analysis of federal legislative CO_2 proposals. The Company assumes that compliance comes in the form of a CO_2 price, as well as technological standards for new plants. PGE also assumes CO_2 emissions for the Company are regulated at the point of combustion. The portfolio analysis includes scenarios with the Clean Power Plan active and inactive. The reference case assumes full regulatory compliance for particulates, SO_X, NO_X, and mercury emissions for all our plants. PGE assumes potential new portfolio additions to also be in full compliance.	Chapter 10, Modeling Methodology

Guideline 8 (Order 08-339)	Environmental Costs	PGE Compliance	Chapter
Guideline 8b	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Consistent with Order 07-002, PGE plans for the acquisition of major new resources until 2025, hourly dispatch (for variable costs) via AURORAxmp through 2050, and recovery of life-cycle resource investment and fixed costs, including estimated decommissioning. PGE tests its portfolios against futures that incorporate a range of future CO_2 prices. The set of futures is broad and diverse, reasonably reflecting the types of changing circumstances that could be encountered and the resulting impact on the cost and risk of various portfolio choices.	Chapter 10, Modeling Methodology
Guideline 8c	TRIGGER POINT ANALYSIS. The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	PGE tests the CO_2 price which would trigger the selection of a portfolio that is substantially different from the Preferred Portfolio. The Company evaluated an additional regulatory future for the top-scoring portfolios to test the sensitivity of PGE's Action Plan to changes in CO_2 costs.	Chapter 10, Modeling Methodology Chapter 12, Modeling Results

Guideline 8 (Order 08-339)	Environmental Costs	PGE Compliance	Chapter
Guideline 8d	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including the state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	Several of PGE's portfolios, considered for the Action Plan, achieve Oregon's 2035 interim CO_2 goal. PGE presents full cost and risk metrics those portfolios. The Company constructed an additional portfolio to test the incremental resource actions necessary to achieve the 2050 goal on a forecast basis.	

Guideline 9	Direct Access Loads	PGE Compliance	Chapter
	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Currently, PGE excludes estimated five-year opt-out load based on current customer elections. The Company does not plan long-term capacity resources to meet the potential demand from five-year opt-out customers. Nonetheless, according to Oregon law and related OPUC rules, PGE also remains the provider of last resort for all customers in its system.	Chapter 4, Resource Need

Guideline 10	Multi-state Utilities	PGE Compliance	Chapter
	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	N/A	N/A

Guideline 11	Reliability	PGE Compliance	Chapter
	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and	PGE analyzed reliability by introducing a reliability constraint in the development of portfolios. The Company used a loss-of-load assessment to determine the capacity	Chapter 5, Resource Adequacy

Guideline 11	Reliability	PGE Compliance	Chapter
	expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation and storage, along with demand side resources, to reliably meet peak, swing and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	need and maintain resource adequacy. PGE also developed a single comprehensive loss-of-load model for assessing capacity need, renewable capacity contribution, and evaluating portfolio reliability, creating a consistent methodology through the IRP process. PGE models this using the RECAP model; with the goal of constraining the maximum hours of unserved load to 2.4 hours a year.	Chapter 10, Modeling Methodology

Guideline 12	Distributed Generation	PGE Compliance	Chapter
	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PGE evaluates distributed generation (including avoided generation technologies, including DSG, DR, EE, and distributed solar) on par with other supply-side resources. These technologies do not include line losses and transmission costs that are included for central station supply-side resources in the evaluation when such facilities are located outside the service territory.	Chapter 6, Demand Options

Guideline 13	Resource Acquisition	PGE Compliance	Chapter
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	PGE describes its proposed Action Plan, including strategies to acquire supply-side renewables and capacity resources, demand-side resources, and integration resources.	Chapter 13, Action Plan
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	PGE provides a discussion of the advantages and disadvantages of resource ownership relative to PPAs in Chapter 7, Supply Options.	Chapter 7, Supply Options
	Identify any Benchmark Resources it plans to consider in competitive bidding.	At this time, PGE does not plan to submit Benchmark Resources in any RFP that it conducts to acquire capacity resources. PGE is currently exploring renewable resource	2016 IRP Executive Summary

Guideline 13	Resource Acquisition	PGE Compliance	Chapter
		options that could receive consideration as a Benchmark Resource in a renewable RFP.	
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	N/A to PGE	N/A

	Flexible Capacity Resources (Order No. 12-013)	PGE Compliance	Chapter
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g., ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;	PGE conducted a flexibility study with the consulting firm Energy & Environmental Economics (E3) that considered the operational impacts of ramping events, subhourly net load fluctuations, forecast errors, and low net load conditions. The study made use of the REFLEX model, which simulates 5-minute dispatch and incorporates reserve requirement to accommodate both contingencies and ramping needs within each 5-minute interval. The study included an exploration of the impacts of existing renewables and new renewable resource acquisition on the demand for flexibility.	Chapter 5, Resource Adequacy
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g., ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and	The E3 study included the balancing reserve capability of existing generating resources.	Chapter 5, Resource Adequacy
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	The E3 Study evaluated the use of combined cycle, frame combustion turbine and reciprocating engines to mitigate flexibility challenges on the system. PGE also analyzed the use of energy storage (battery systems) for the supply of flexible capacity. The adoption of EVs is forecast to be relatively modest during the action plan time horizon and	Chapter 5, Resource Adequacy Chapter 8, Energy Storage Chapter 13, Action

Flexible Capacity Resources (Order No. 12-013)	PGE Compliance	Chapter
	therefore does not present an effective means for filling the gap between the demand and supply of flexible capacity. PGE is engaged in OPUC docket AR 599 and will follow EV developments in order to take advantage of future changes in adoption potential.	Plan

APPENDIX B. PGE's Compliance with 2013 IRP Order (Order 14-415)

TABLE B-1: Commission Requirements from PGE's 2013 IRP Order No. 14-415, pp. 5-6

SUPPLY-SIDE REQUIREMENTS	PGE Compliance	Chapter
Conduct a series of Workshops with Stakeholders (& one with Commissioners) to develop multiple portfolios to meet incremental capacity & energy needs	PGE and IRP stakeholders engaged in multiple public input meetings to discuss and develop portfolios for the 2016 IRP. PGE discussed portfolios with the Commissioners at a public meeting on April 21, 2016.	Chapter 2, IRP Public Process Appendix C, Public Process Agendas
Portfolios to include:	**The 2016 IRP includes:**	
■ Increased renewable resource generation comparable in risk and cost to a portfolio based on natural gas	■ Multiple portfolios with increased renewable penetration	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail
■ Maintaining an open position (buy spot or short term electricity)	■ Two portfolios with different open position levels	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail
■ Boardman powered with biomass as a peaker or base-load plant	■ One portfolio looking at a biomass baseload plant at Boardman	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail
■ Developing new storage facilities	PGE is an active participant in UM 1751, a docket opened after Order 14-415 was issued to adopt guidelines for utilities to use in submitting proposals for energy storage systems and for examining the potential value of energy storage system technology.	Chapter 8, Energy Storage
■ Examine and analyze various Colstrip shutdown scenarios	PGE performed analysis for different Colstrip shutdown scenarios.	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail
Portfolios Accelerating:		
■ Energy Efficiency Programs	The 2016 IRP includes a portfolio with EE deployment higher than the base Energy Trust of Oregon (Energy Trust) forecast (base vs. non cost-effective EE).	Chapter 6, Demand Options
■ Demand response (DR) programs	PGE targets DR programs that provide firm, cost-effective capacity that addresses the conditions specific to the Company's service territory.	Chapter 6, Demand Options Appendix I, Demand Response Programs

SUPPLY-SIDE REQUIREMENTS	PGE Compliance	Chapter
■ Development of Distributed Generation Resources	PGE commissioned Black & Veatch in the fourth quarter of 2014 to perform a Distributed Generation (DG) market potential study. The study found no significant cost-effective potential DG penetration in PGE's territory before 2035.	Chapter 7, Supply Options Appendix F, Distributed Generation Studies

TABLE B-2: Commission Requirements from PGE's 2013 IRP Order No. 14-415, p. 9 – demand-side actions

Demand-Side Requirements	PGE Compliance	Chapter
Notify Staff of any proposed changes to the EnerNoc contract baseline	PGE notified Commission Staff of changes made around eligibility/exclusivity/targets, through the annual report on the Energy Partner^{SM} program, which the Company files in Dockets UE 272/UM 1514. None of the changes affected the program's baseline.	Chapter 6, Demand Options
Include a portfolio analysis of Conservation Voltage Reduction (CVR)	All portfolios in the 2016 IRP include a CVR potential forecast.	Chapter 10, Modeling Methodology Appendix O, Portfolio Detail

TABLE B-3: Commission Requirements from PGE's 2013 IRP Order No. 14-415, pp. 10-11 – enabling studies

Requirements pertaining to Enabling Studies	PGE Compliance	Chapter
Convene workshops with stakeholders to examine PGE's load forecast methodology	PGE conducted a study in 2015 to examine the methodology of the long-term energy and capacity load forecasts. PGE presented study results to stakeholders in a series of workshops and public meetings in 2015. The Company incorporated changes to the load forecast methodology in the forecast used in the 2016 IRP.	Chapter 4, Resource Need
Conduct a comprehensive cost-benefit analysis of joining the CAISO/PAC EIM	PGE commissioned Energy + Environmental Economics (E3) to perform a comparative study of the potential economic benefits of PGE's participation in the Western Energy Imbalance Market (EIM) and filed the results of this study with the OPUC on November 25, 2015. The Company also reported on the EIM study in its 2013 IRP Update filed on December 2, 2015.	LC 48
Create steering committee to oversee study	PGE created a steering committee, including representatives of OPUC staff,	LC 48 see PGE's filing of

Requirements pertaining to Enabling Studies	PGE Compliance	Chapter
	stakeholders, and industry experts, to oversee the study.	November 25, 2015
Estimate diversity benefits	The E3 study estimated diversity benefits by reducing the flexible reserve requirements for participating zones to reflect the pooling of Variable Energy Resources (VER) and load forecast error and variability across the Western EIM or Northwest Power Pool Mid-Columbia System Constrained Economic Dispatch (NWPP MC SCED) footprint as a whole.	LC 48 see PGE's filing of November 25, 2015
Estimate benefits of going to 5-minute dispatch	The E3 analysis used PLEXOS to estimate PGE's benefit of participating in the EIM by comparing PGE's real-time generation costs as an EIM participant, as well as any EIM energy revenues and purchase costs, against a Business-As-Usual scenario in which PGE does not participate in either regional real-time market.	LC 48 see PGE's filing of November 25, 2015
Evaluate reliability benefits	PGE reviewed studies by NREL and FERC that document the reliability benefits of joining an EIM. PGE found that participation in the Western EIM would provide reliability benefits for PGE in terms of expanded footprint and greater diversity.	LC 48 see PGE's filing of November 25, 2015
Estimate benefits of deferring or eliminating the need for new generation & other flexible resources	As described in the E3 report, EIM participation does not alleviate the responsibilities of Balancing Authorities (BAs) to carry adequate reserves. Within an EIM, the BAs remains responsible for meeting its peak load and demonstrating resource sufficiency. While EIM participation will not reduce planning reserves or impact resource additions, the EIM will reduce operating reserve-carrying requirements due to the diversity benefit of the EIM	LC 48 see PGE's filing of November 25, 2015
Present at Commissioner workshop	PGE presented the results of the Comparative Study at an OPUC workshop on December 1, 2015.	LC 48

TABLE B-4: Commission Requirements from PGE's 2013 IRP Order No. 14-415, pp. 13-14 – other requirements

Other Requirements	PGE Compliance	Chapter
Develop & evaluate multiple RPS compliance strategies:		
▪ Alternatives to physical compliance	PGE developed its 2016 IRP portfolios considering different levels of Renewable Portfolio Standards (RPS) physical compliance.	Chapter 5, Resource Adequacy Chapter 12, Modeling Results Appendix O, Portfolio Detail
▪ Recommend a least-cost strategy in next IRP Update and future IRPs	In the 2016 IRP analysis, the Company selected a Preferred Portfolio which represents resources that provide the best combination of expected cost and risk for PGE and its customers. The Action Plan recommends the issuance of one or more requests for proposals to acquire resources that maintain resource adequacy and align with the key attributes specified in portfolio evaluation.	Chapter 12, Modeling Results Chapter 13, Action Plan
111(b) & (d) Requirements		
▪ Model and perform analysis of known and expected requirements	PGE performed portfolio analysis to model 111(b) and (d) requirements. Results of the analysis will include in the 2016 IRP.	Chapter 3, Planning Environment Chapter 10, Modeling Methodology Chapter 12, Modeling Results
▪ Present results at a workshop w/ Commissioners	PGE presented Clean Power Plan analysis results to the Commissioners in a Public Meeting on April 21, 2016.	

TABLE B-5: Non-Commission Requirements – enabling studies

Enabling Studies	PGE Compliance	Chapter
Assessment of DG potential, including CHP projects	In 2014, PGE commissioned Black & Veatch to conduct a distributed generation market potential study. PGE reported findings from the study in the 2013 IRP Update and includes additional information in the 2016 IRP.	Chapter 7, Supply Options Appendix F, Distributed Generation Studies
Assessment and development of operational flexibility	PGE continues the implementation of the Dynamic Dispatch Program (DDP), which has improved the ability of the Company's existing resources to provide flexible capacity. PGE reported the progress of the DDP in the 2013 IRP update.	LC 48 – PGE's 2013 IRP Update (filed Dec. 2, 2015)
Comprehensive analysis of flexible resource options, including options that lower the need for and cost of reserves	PGE worked with Energy + Environmental Economics (E3) on a flexibility capacity analysis using REFLEX to evaluate different levels of renewables penetration into PGE's current resources portfolio. The 2016 IRP provides the results of the analysis.	Chapter 5, Resource Adequacy
Evaluation of new analytical tools for optimizing flexible resource mix	PGE evaluated and employed E3's REFLEX model as a tool for its resource flexibility analysis.	Chapter 5, Resource Adequacy

APPENDIX C. Public Process Agendas

Public Meeting #1: April 2, 2015

- 2009 IRP and 2011 RFP Resource Update
- Public Process Overview
- 2013 IRP Order
- Load Forecast
- Preliminary Load Resource Balance
- Load Forecast Methodology
- Environmental Policy

Commission Meeting #1: July 15, 2015

- Clean Power Plan - 111(d) Modeling
- EIM Comparative Study

Technical Workshop #1: July 15, 2015

- Overview of Modeling Initiatives
- Long Term Energy Model
- Peak Demand Model
- Treatment of Programmatic Energy Efficiency
- Q&A

Public Meeting #2: July 16, 2015

- Public Process Overview
- Load Forecast Summary
- Energy Efficiency
- Distributed Generation
- Supply-side Resources

Public Meeting #3: August 13, 2015

- Public Process Overview
- Capacity Update
- Flexibility Update
- Demand Response Update

- Load Forecast
- Natural Gas Forecast
- Portfolio and Future Ideation

Public Meeting #4: September 25, 2015

- Public Process
- Clean Power Plan Update
- Climate Study Review
- Conservation Voltage Reduction

Public Meeting #5: December 17, 2015

- Public Process Overview
- 2013 IRP Update
- Integrated (Smart) Grid
- Energy Storage and HB 2193
- Demand Response Potential Study
- Planning Reserve Margin/Capacity Contribution
- Portfolios and Futures

Roundtable #16-1: March 9, 2016

NOTE: In 2016, PGE began referring to its public meetings and technical workshops as Roundtables and naming them with a number that provides the year and number of the meeting.

- Overview
- RPS Landscape
- Resource Adequacy
- Scoring Metrics
- Portfolios

Commission Meeting #2: April 21, 2016

- Clean Power Plan Update
- Resource Portfolios Update

Roundtable #16-2: May 16, 2016

- Overview
- RPS Compliance

- Portfolios & Resources
- Modeling Methodology
- Flexible Capacity Study
- Energy Storage
- Boardman Biomass
- IRP Feedback & Next Steps

Roundtable #16-3: August 17, 2016

- Stakeholder process
- Resource need assessment
- Scenario analysis and results
- Draft Action Plan
- Energy Storage evaluation
- Next Steps

Roundtable #16-4: November 16, 2016

The agenda for this meeting was under development at the time of filing the 2016 IRP.

APPENDIX D. Existing Resources

A diverse portfolio of existing resources contributes to meeting the energy and capacity needs of PGE's system. These resources are described in three main sections below: Section D.1, PGE Power Plants, Section D.2, Contracts, and Section D.3, Customer Side.

D.1 PGE Power Plants

D.1.1 Thermal Resources

PGE has an ownership interest in five power plants fueled with natural gas, all located in Oregon:

- Beaver,
- Coyote Springs,
- Port Westward,
- Port Westward 2, and
- Carty;

and two fueled with coal:

- Boardman, located in Oregon, and
- Colstrip, in Montana.

In the following section, PGE provides the technology and size characteristics for each plant. It is important to note that in these descriptions, capacity (MW) represents the annual average net capacity of the power plant, inclusive of any duct-firing capabilities and excluding any de-rates for maintenance or forced outage rates. Most combined cycle combustion turbines (CCCTs) provide less capacity in the summer, when high temperatures affect operations, while other steam technologies are less sensitive to temperature. In contrast, energy is in MWa and represents the annual average availability after projected forced outages and maintenance.[223]

D.1.1.1 Beaver

Beaver is a CCCT facility located in Clatskanie, Oregon. PGE placed the plant into service in 1976. Beaver has an annual average capacity of 491 MW. The six combustion turbines (CTs) operate primarily on natural gas, but also have the ability to be fueled with No. 2 diesel fuel oil via an on-site tank storage. The CTs each have heat recovery steam generators that connect to a single steam turbine, allowing PGE to operate the plant either in simple-cycle mode or in combined–cycle mode. A separate simple cycle unit, Beaver 8 (added to the site in 2001) has an annual average capacity of 25 MW. As PGE generally uses Beaver for peaking and wind-following purposes, the plant is not included in the energy load-resource balance (LRB) for this IRP.

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[223] PGE excludes peaking units and duct firing are excluded from average energy.

D.1.1.2 Coyote Springs

Coyote Springs is a gas-fired CCCT facility located in Boardman, Oregon, which became operational in 1995. Coyote Springs has an annual average capacity of 246 MW (including 2 MW of additional capacity when operating an auxiliary boiler to supply steam to steam customers) and an average annual energy availability of 228 MWa.

D.1.1.3 Port Westward 1

Port Westward 1 (PW1) reached commercial operation in June 2007. The CCCT plant, located in Clatskanie, Oregon, is among the most efficient natural-gas-fired generators of its type in the Northwest. The plant supplies approximately 395 MW of annual average capacity (including approximately 19 MW of duct firing) and has an average annual energy of 334 MWa.

D.1.1.4 Port Westward 2

Port Westward 2 (PW2) is located in Clatskanie, OR, adjacent to PGE's PW1 plant. PW2 entered commercial operations in December 2014. It is composed of 12 natural gas-fired reciprocating engines with a total annual average capacity of approximately 222 MW. In addition to providing peak capacity, the modular configuration provides a wide range of dispatch flexibility for wind, load following, and additional ancillary services.

D.1.1.5 Carty

Carty is a 434 MW (annual average capacity, inclusive of 48 MW duct firing) CCCT resource built adjacent to PGE's Boardman coal plant in Boardman, Oregon. The plant includes a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. The plant became operational on July 29, 2016. The average annual energy is 357 MWa.

D.1.1.6 Boardman

Boardman is a pulverized coal plant located in Boardman, Oregon with an annual average capacity of approximately 570 MW. It came into service in 1980 and will cease coal-fired operations by year-end 2020. The plant burns coal transported by rail from the Powder River Basin. PGE is the operator of the plant, and has a 90% ownership interest, equal to a 513 MW share of the plant. The Company has the obligation to sell 10% of the plant's output to Turlock Irrigation District (TID) until year-end 2018. The average annual energy availability for PGE is 394 MWa, increasing to approximately 444 MWa in 2019, when the TID obligation expires. Idaho Power owns the remaining 10% of Boardman. A discussion of PGE's research regarding the technical and economic viability of a conversion of Board man to biomass fuel is available in Section 7.2.3.1, Boardman Biomass Project.

D.1.1.7 Colstrip

Colstrip Units 3 and 4 are coal-fired units located in Colstrip, Montana. The plants went into service in 1984 and 1986, respectively. Talen Generation LLC operates and manages the Colstrip plant. PGE owns 20% of Units 3 and 4, representing approximately 296 MW of annual average capacity. Colstrip is a mine-mouth plant, with coal transported by conveyor belt directly from the on-site mine to the boiler. The annual average energy availability for PGE's share of Colstrip Units 3 and 4 is 262 MWa.

Per SB 1547, this IRP includes the removal of Colstrip Units 3 and 4 from the Company's resource stack by January 1, 2035.

D.1.2 Hydro Plants

PGE owns and operates eight hydroelectric plants on the Deschutes, Clackamas, and Willamette River systems. Two plants, Pelton and Round Butte, have reservoir storage flexibility, while the remaining plants have a limited ability to store water and shape energy. PGE generally operates these plants as run-of-river projects.

In addition to energy production, these resources (mainly Pelton and Round Butte) provide peaking and load-following capabilities.[224] A portion of PGE's hydro capacity also contributes to meeting required spinning and supplemental (non-spin) operating reserve requirements, which are necessary for responding to system contingencies.

D.1.2.1 Pelton-Round Butte Hydro Project

PGE operates the Pelton and Round Butte plants located on the Deschutes River near Madras, Oregon. FERC issued a new 50-year license for this project on June 21, 2005. The plants have a combined annual average dependable capacity[225] of approximately 448 MW and an expected annual energy production of 165 MWa under average hydro conditions. PGE owns 66.67% of each plant (~299 MW, 110 MWa), with the remaining shares owned by the Confederated Tribes of the Warm Springs Reservation (Tribes). The Tribes have the right to increase their ownership shares to 49.99% on December 31, 2021, and in this IRP, assumes that the Tribes exercise this right, reducing PGE's shares of Pelton and Round Butte.[226] The Tribes agreed to sell all of their output to PGE through 2024. See Section D.2, Contracts, below for more details on the agreement.

D.1.2.2 Clackamas River Hydro Projects

PGE owns and operates five plants located on the Clackamas River system. FERC issued a new 45-year license for the projects on December 21, 2010.[227] The plants, with their average annual dependable capacities, are:

- Harriet Powerhouse (0.5 MW)
- Oak Grove (31 MW)
- North Fork (29 MW)
- Faraday (29 MW)
- River Mill (16 MW).

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[224] As noted in Section 5.1.3, RECAP Model Inputs, PGE hydro projects were modeled with the same monthly sustained maximum capacity values used in the 2013 IRP. Due to limited time, the Company did not reexamine the values in this IRP. In a future IRP cycle, PGE plans to evaluate the plant capabilities under current licensing and habitat requirements.

[225] The annual average of each month's estimated maximum generation maintainable for four hours under average hydro conditions.

[226] In this IRP, the Tribes' initial option to update the ownership shares to 49.99% at the end of 2021 is modeled as a simplified 50%. The Tribes have a second option to update their ownership shares to 50.01% on December 31, 2036.

[227] The FERC license was amended on August 15, 2014 to include the Harriet Powerhouse.

The total expected annual energy production is 77 MWa under average hydro conditions. The Harriet Powerhouse became operational in late December 2015. It is an RPS compliant microturbine located at "Crack-in-the Ground" below Lake Harriet Dam.

D.1.2.3 Willamette Falls Hydro Project

PGE owns and operates the Sullivan plant, located on the Willamette River at Willamette Falls. FERC issued a new 30-year license on December 8, 2005.[228] The plant's average annual dependable capacity is 16 MW and the expected annual energy production is 15 MWa under average hydro conditions.

D.1.3 Wind and Solar Plants

D.1.3.1 Tucannon River Wind Farm

Located near Dayton, Washington, PGE's Tucannon River Wind Farm (Tucannon) consists of 116, 2.3 MW Siemens wind turbine generators and has a total nameplate capacity of 267 MW. The plant's 38.2% expected capacity factor results in an output of 102 MWa. The project was completed and operational in December 2014, ahead of schedule, and generation from Tucannon is RPS compliant.

D.1.3.2 Biglow Canyon

Completed in three phases in 2007, 2009, and 2010, the Biglow Canyon Wind Farm (Biglow), located in the lower Columbia River Gorge near Wasco, Oregon, has a total nameplate generating capacity of 450 MW. Based on an expected capacity factor of approximately 30%, PGE estimates Biglow's annual average energy production at 135 MWa. Biglow's generation is RPS compliant.

D.1.3.3 Solar

PGE owns three solar photovoltaic (PV) projects: Sunway 1 (ODOT I5 & I205), Sunway 2 (Prologis), and Sunway 3 (Prologis 2). These projects entered service between 2008 and 2010 and are located on multiple properties in PGE's service territory. The original leases have all transferred to PGE ownership. The combined AC rating is approximately 3.2 MW and the forecasted average energy is 0.5 MWa. The Clean Wind Fund receives a portion of the RECs associated with these projects. PGE's leased PV projects are included in Section D.2, Contracts.

D.1.4 Energy Storage: Salem Smart Power Center (SSPC)

PGE deployed a 5 MW (1.25 MWh) Li-ion battery inverter system at the SSPC as part of the Pacific Northwest Smart Grid Demonstration. This advanced Li-ion battery system provides uninterrupted power, reactive power (VAR support), ancillary services, and can also be configured for use as energy storage for small-scale ancillary services in firming and shaping variable resources, such as solar and wind generation. The SSPC was part of a regional and visionary transactive control demonstration project co-funded by the US DOE under the American Recovery and Reinvestment Act. The primary contractor was Battelle, with PGE serving as a subcontractor on the project. PGE has created substantial leverage through its approximately $6 million investment, which has been matched three-to-one by the US DOE and other partners.

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[228] For this IRP, PGE assumes the Willamette Falls Hydro Project FERC license is renewed.

PGE formally launched the project in 2010 and went live in May 2013. At the end of the demonstration, in January 2015, PGE confirmed that project assets are responsive to transactive control. The resulting assets, especially the battery inverter system, continue to operate as part of PGE's transmission and distribution system. Its current use is to provide routine automatic under-frequency response in compliance with NERC BAL-003-1. As of this writing, 15 potential use cases have been identified for the battery inverter system.

PGE will be collaborating with the Pacific NW Laboratory via funding from the US DOE Grid Modernization Program to optimize the most likely use cases for concurrent and or sequential use. At present, the SSPC battery inverter system can only operate one use case at a time, thus, should optimization point to concurrent uses, SSPC control software will also have to be upgraded to implement the selected uses.

D.2 Contracts

PGE's resources include a variety of contracts for both energy and capacity. This section summarizes the long and mid-term contracts included in this IRP (executed as of May 31, 2016).

D.2.1 Hydro System Contracts

The hydro capacity values in this section represent annual average dependable values, not plant capacities.

D.2.1.1 Mid-C

PGE has contracts for project shares for the some of the hydro facilities on the mid-section of the Columbia River (Mid-C). The shares include proportional rights to the project reservoirs, allowing for shaping of energy across hours and days.[229] PGE also has the ability to utilize these resources to provide ancillary services, including regulation and spinning reserves.

Wells

The Wells Dam is located downstream of Chief Joseph and was completed in 1967. The 10-turbine facility is operated by the Douglas County PUD No. 1 (Douglas PUD). PGE has contractual rights to 19.39%[230] of the project through August 31, 2018. The annual average dependable capacity of PGE's share is approximately 133 MW and the expected annual average energy under average hydro conditions is 85 MWa (both values are prior to PGE's associate Canadian Entitlement obligations; see Section D.2.1.4, Canadian Entitlement Allocation). Per OPUC Order No. 14-415, PGE seeks to renew all or a portion of the Wells contract if a cost-effective agreement can be reached.[231]

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[229] The ability of Mid-C project to provide shaping and ancillary services varies across seasons and between years due to operating constraints and streamflow conditions.

[230] PGE's original share of 20.3% was reduced to 19.39% as part of the 2004 settlement agreement between Douglas PUD and the Confederated Tribes of the Colville Reservation.

[231] OPUC Order No. 14-415, III.A.2.b.

Priest Rapids Project

The Priest Rapids Project is located downstream of Rock Island and consists of the Wanapum Dam (10 units, completed in 1964) and the Priest Rapids Dam (10 units, completed in 1961). Both facilities are operated by the Grant County PUD No. 2 (Grant PUD). PGE has contractual rights to approximately 8.62% of each facility through the spring of 2052. The combined annual average dependable capacity of PGE's share is approximately 125 MW and the expected annual average energy under average hydro conditions is 87 MWa (both values are prior to PGE's associated Canadian Entitlement obligations; see Section D.2.1.4, Canadian Entitlement Allocation).

D.2.1.2 Pelton, Round Butte, Re-reg

As discussed above, the Confederated Tribes of the Warm Springs Reservation (Tribes) have a 33.33% ownership share of the Pelton and Round Butte plants with contractual rights to increase their ownership to 49.99% at the end of 2021. The Tribes also own 100% of the associated Re-regulating Dam (Re-reg Dam, 10 MW, 10 MWa), which is operated by PGE. PGE and the Tribes entered into an agreement for PGE to purchase the Tribes' shares of Pelton, Round Butte, and the Re-reg Dam from 2015 through 2024.

D.2.1.3 Portland Hydro Project

PGE has a contract with the City of Portland to purchase the output of the Portland Hydro Project, located on the Bull Run River. The contract runs through 2017 and provides 10 MWa with a varying capacity contribution.

D.2.1.4 Canadian Entitlement Allocation

This agreement relates to the Columbia River hydro projects. Columbia River storage reservoirs located in Canada are operated to increase the overall value of the Columbia River hydro system. A portion of the generation benefits received by the projects in the US are shared with Canada. The original agreement for the entitlement benefits ended in 2003, but an extension agreement is effective until 2024. PGE's share of Mid-C projects (Wells, Wanapum, and Priest Rapids; see Section D.2.1.1, Mid-C) are subject to obligations for the Canadian Entitlement Allocation Extension.
PGE models this as a delivery of on-peak power to Canada. For the purposes of this IRP, PGE assumes that the CEAE renews after 2024 (or that the net effect of any operating changes after the expiration is approximately the same as if the agreement is renewed).

D.2.1.5 Wells Settlement Agreement

Under this agreement with Douglas County PUD, PGE purchases non-firm energy. This contract expires in August, 2018. The quantities vary by month and by On- and Off-peak. For 2017-2018, the monthly MWa On-peak values are expected to vary from approximately 0 to 14 MWa.

D.2.1.6 North Wasco PUD

PGE signed an agreement with Northern Wasco County PUD to purchase the entire output of the Dalles Fishway Northshore Hydroelectric Project. This contract replaces a QF contract with the same plant that expired in 2015. It provides PGE with approximately 5 MW of average annual capacity and 5 MWa of annual average energy through September 2017.

D.2.2 Wind Contracts

D.2.2.1 Klondike II

PGE has a power purchase agreement with Iberdrola Renewables for the entire output of the 75 MW Klondike II Wind Farm located in Sherman County, OR. The expected output is approximately 25 MWa annually. Iberdrola provides firming and shaping services for the output of the plant. This contract runs through 2035. PGE receives the RECs associated with the generation.

D.2.2.2 Vansycle Ridge

PGE entered into a PPA in 1997 with ESI Vansycle Partners to purchase the output of the Vansycle Ridge Wind Farm located north of Pendleton along the Washington/Oregon border. The plant is approximately 25 MW with an expected annual output of 8 MWa. The PPA expires in 2027. BPA provides firming and shaping for this contract. PGE receives the RECs associated with the generation.

D.2.3 Additional Contracts

Table D-1 summarizes additional contract resources in PGE's existing portfolio. Qualifying Facility (QF) agreements are included in Table D-2.

TABLE D-1: Summary of additional contracts

Contract	Type[1]	In-Serv[2]	Exp[2]	MW[3]	MWa[4]
Baldock Solar	RE	Jan 2012	Jan 2037	1.5	0.2
Bellevue Solar	RE	Jul 2011	Jan 2036	1.4	0.2
Yamhill Solar	RE	Jul 2011	Oct 2036	1.0	0.1
Outback Solar	RE	Oct 2012	Jan 2037	5.0	1.2
Portland Public Schools Solar	RE	Oct 2015	Sep 2040	1.2	0.2
EWEB Stone Creek	CAP	—	—	0.6	—
Iberdrola Summer Peak	CAP	Jul 2014	Sep 2018	100	—
Iberdrola Winter Peak	CAP	Dec 2014	Feb 2019	100	
Shell Option	OPT	Mar 2014	Dec 2017	300	—
Covanta Marion	PPA	Jul 2014	Sep 2017	8.0	9.6

1. Type indicates either a renewable purchase agreement (RE), capacity contract (CAP), option (OPT), or power purchase agreement (PPA). PGE receives all or a portion of the RECs associated with RE contracts.
2. Approximate in-service and expiration dates.
3. AC rating for solar projects, average annual contribution for EWEB Stone Creek, firm energy for Covanta.
4. Approximate expected average energy.

D.2.4 Qualifying Facility Contracts

PGE has contracted to purchase the output of numerous QF projects as required by PURPA regulations. The 2016 IRP includes QF contracts executed as of May 31, 2016, totaling approximately 223 MW. A substantial portion of these contracts are recently executed solar contracts. Table D-2 provides a summary of the QF contracts.

TABLE D-2: Qualifying Facility contract summary

Contract	Type[1]	In-Serv[2]	Exp[2]	MW[3]	MWa[4]
Biogas / Digester					
Green Lane Energy Biogas QF	ST	Jul 2012	Dec 2031	1.6	1.4
Coffin Butte Biogas QF (PNGC)	ST	Dec 2012	Sep 2027	5.7	5.4
Forest Glen Oaks Biogas QF	ST	Feb 2013	Oct 2027	0.4	0.3
Tillamook Bay Digester QF	ST	Jan 2014	Dec 2028	0.8	0.8

Contract	Type[1]	In-Serv[2]	Exp[2]	MW[3]	MWa[4]
SORT Biogas QF	RE	Oct 2018	Nov 2030	2.2	1.4
Hydro / Water System					
Von Family Hydro QF	ST	Feb 2014	Feb 2029	0.2	<0.1
Minikahda Hydro QF	ST	Feb 2014	Feb 2029	0.2	<0.1
Conduit 3 Water System QF (Lucid)	ST	Jun 2013	Dec 2032	0.2	0.1
Tualatin Valley Water District QF	ST	Apr 2013	Mar 2028	<0.1	<0.1
Wind					
Patu Wind QF	ST	May 2011	May 2031	9.0	3.0
Solar					
Domaine Drouhin Solar QF	ST	Aug 2008	Apr 2028	<0.1	<0.1
Starbuck Solar QF	ST	Jan 2011	Nov 2030	<0.1	<0.1
Steel Bridge Solar QF	ST	Aug 2015	Feb 2034	2.5	0.4
Fossil Lake Solar QF	RE	Mar 2017	Mar 2035	10.0	2.5
Lakeview Solar QF	RE	May 2018	Jul 2035	10.0	2.8
NorWest Energy 14 (Grande Ronde)	RE	Dec 2016	Dec 2031	2.2	0.4
SP Solar 1 (Interstate)	RE	Dec 2016	Jul 2035	2.2	0.3
SP Solar 2 (Goose Creek)	RE	Dec 2016	Jul 2035	2.2	0.3
SP Solar 5 (Mill Creek)	RE	Dec 2016	Jul 2035	2.2	0.3
SP Solar 6 (Colton)	RE	Dec 2016	Jul 2035	2.2	0.3
SP Solar 7 (Dayton Cutoff)	RE	Dec 2016	Jul 2035	2.2	0.3
SP Solar 8 (Valley Creek)	RE	Dec 2016	Jul 2035	2.2	0.3
Willamina Solar	RE	Dec 2016	Nov 2035	0.5	<0.1
OE Solar 1 (One Energy)	RE	Oct 2018	Oct 2033	10.0	2.6
OE Solar 2 (One Energy)	RE	Dec 2017	Dec 2032	5.0	1.3
Morrow (One Energy)	RE	Sep 2018	Sep 2033	10.0	2.6
Tygh Valley Solar	RE	Dec 2018	Jan 2032	10.0	2.1
Starvation Solar	RE	Dec 2018	Jan 2032	10.0	2.2
Dayton Solar I	RE	Dec 2018	Jan 2032	10.0	1.8
Wasco Solar 1	RE	Dec 2018	Jan 2032	10.0	2.1
Sheep Solar	RE	Jun 2017	Jan 2036	2.2	0.5
Silverton Solar	RE	Dec 2016	Jan 2036	2.2	0.4
Butler Solar	RE	Dec 2017	Jan 2036	4.0	0.9

Contract	Type[1]	In-Serv[2]	Exp[2]	MW[3]	MWa[4]
Drift Creek	RE	Jul 2017	Jan 2036	2.2	0.4
Glenn Creek	RE	Nov 2017	Jan 2036	2.2	0.3
Boring Solar	RE	Oct 2017	Jan 2036	2.2	0.2
OE Solar 3 (Wy'East)	RE	Dec 2018	Dec 2033	10.0	2.6
OE Solar 4 (One Energy)	RE	Jun 2018	Jun 2033	10.0	2.5
Fort Rock Solar I	RE	Jan 2019	Apr 2032	10.0	2.2
Fort Rock Solar II	RE	Jan 2019	Apr 2032	10.0	2.2
Ballston Solar, LLC	RE	Sep 2017	May 2036	2.2	0.3
Amity Solar	RE	Nov 2017	Apr 2036	4.0	0.9
Firwood Solar	RE	Nov 2017	Apr 2036	10.0	2.3
Stringtown Solar	RE	Nov 2017	Apr 2036	4.0	0.9
Bridgeport Solar	RE	Nov 2017	Apr 2036	7.0	1.7
Starlight Solar	RE	Nov 2017	Apr 2036	4.0	0.9
Duus Solar	RE	Nov 2017	Apr 2036	10.0	2.1
Fishback Solar	RE	Nov 2017	Apr 2036	3.0	0.7
QF Total				**223**	**58**

1. Type indicates either a standard (ST) or renewable (RE) QF contract. PGE receives RECs for a portion of the term of renewable QF contracts.
2. Approximate in-service and expiration dates.
3. Approximate plant capacities. AC rating for solar projects.
4. Approximate expected average energy.

D.3 Customer Side

D.3.1 Dispatchable Standby Generation

PGE’s innovative DSG program works with customers to utilize customer-sited backup generators to provide non-spinning reserves. At year-end 2016, PGE expects to have approximately 114 MW of DSG capacity. The Company plans to expand the program to 135 MW in 2021. Chapter 7, Supply Options, discusses the DSG program and outlook in more detail.

D.3.2 Distributed Generation – Solar

There are currently 65 MW of DG solar resources connected to PGE’s distribution system. DG solar is mainly the result from two programs: the Net metering (~48 MWp) and the Feed-In-Tariff (~17 MWp). More information about these two programs is available in Section 7.1, Distributed Generation. Additional customer side solar resources are connected to the PGE grid and are developed as qualifying facilities. They amount to ~12 MWp.

D.3.3 Non-Solar Distributed Generation

There are currently approximately 8 MW of non-solar DG installed on PGE's system in the form of: low-impact hydro, small-scale wind, fuel cells, methane gas, and combined heat and power (CHP).

D.3.4 Energy Efficiency

PGE is committed to helping customers reduce their energy use and the Company has a long history of working with the Energy Trust of Oregon (Energy Trust) to identify and acquire all available cost-effective energy efficiency measures. Through the combined efforts of the Energy Trust, customers, and utilities, Oregon is a national leader in capturing energy efficiency. In 2015, Energy Trust programs added over 30 MWa of additional EE savings.[232] Chapter 6, Demand Options, discusses EE programs in more detail.

D.3.5 Demand Response

PGE has sought additional DR capability through various programs, including Schedule 77 curtailment contracts, time-of-use pricing, and a residential direct load control pilot. In particular, the Company contracted with a third-party aggregator to acquire commercial customer automated demand response (ADR). The ADR program launched in 2013 and implemented load reduction events. In the 2013 IRP, PGE targeted the addition of 45 MW of ADR by 2017. Currently, actual numbers are lower than forecasted due to customer exits and less than successful new enrollments. The available DR on PGE's system in 2017 is forecast to be 30 MW. Chapter 6, Demand Options, and Appendix I, Demand Response Programs, discuss DR programs in more detail, including an update of the Brattle Group DR potential study.

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[232] Energy Trust, "2015 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors", updated October 24, 2016, pg 4, PGE net savings.

APPENDIX E. Climate Change Projections in Portland General Electric Service Territory

Climate Change Projections in Portland General Electric Service Territory

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Global & Pacific Northwest Climate Change Synthesis Report

November 2015

A Report to Portland General Electric Company

Prepared by
Oregon Climate Change Research Institute

Climate Change Projections in Portland General Electric Service Territory: Global and Pacific Northwest Climate Change Synthesis Report

A report to Portland General Electric Company

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November 2015

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Summary

Global climate is warming primarily due to human activities, namely burning fossil fuels. The accumulation of carbon dioxide and other greenhouse gases in the atmosphere since the beginning of the Industrial Revolution has caused more heat to remain trapped within the Earth's climate system, causing the planet to warm gradually. While other factors can affect the Earth's temperature (e.g., solar variation, volcanic eruptions, orbital cycles, aerosols), rising greenhouse gases is the dominant factor explaining the observed warming over at least the last half-century.

Climate scientists use sophisticated models of the climate system to project how climate will change under various future scenarios of greenhouse gas emissions. Despite uncertainties and limitations inherent in global climate models, all models agree that with continued greenhouse gas emissions, the Earth's temperature will continue to rise in the future. How much the Earth will warm depends on the magnitude of future emissions and how sensitive the climate is to rising greenhouse gas concentrations.

Temperature: During the last century, the globe's surface temperature rose about 1.5°F and likewise for the Pacific Northwest. Global warming is projected to continue and by mid-21st century, PNW annual warming is projected to be in the range of 3.1°F to 8.5°F with more warming in summer.

Precipitation: Precipitation increased during the last century averaging over Northern Hemisphere mid-latitude land areas annually and in the Pacific Northwest during spring. Precipitation is projected to increase to the north and decrease to the south of the Pacific Northwest where changes could be of either sign. A majority of models project increases year round with decreases in summer.

Snow: Northern Hemisphere snow cover extent receded and PNW spring snowpack declined; both trends are expected to continue in the future. By mid-21st century, snowpack in the Columbia River Basin is expected to decline by as much as nearly 30%.

Streamflow: Watersheds with a snowmelt component to streamflow are most sensitive to a warming climate. The spring streamflow peak shifted up to a month earlier and winter streamflow increased. These trends are expected to continue in the future along reductions in summer flows. Such shifts in streamflow character could potentially decrease hydropower production.

Wildfire: Wildfires have become larger and more frequent and that trend is expected to continue in the future, especially under warmer and drier summers projected for the Pacific Northwest.

Storms: There is some evidence that the storm track has shifted northward and may continue to shift slightly northward in the future. There is as yet no consensus on whether or not extratropical storms will intensify in the North Pacific Ocean.

Wind: There is some evidence that average surface winds have slowed slightly. This trend may continue in the future, but natural variability will continue to dominate.

Clouds: No robust change in cloud cover has been observed. Globally, cloud cover is projected to decrease in the sub-tropics and increase at high latitudes, but future changes in the Pacific Northwest remain uncertain.

In order to limit the rise in the Earth's temperature, future global emissions must stabilize, but also decrease in the future. Mitigating climate changes involves moving the world's energy production, transportation, and industry away from fossil fuel intensive sources toward more renewable energy sources. Other strategies include capturing and sequestering carbon before it reaches the atmosphere, removing carbon dioxide from the atmosphere, increasing energy-use efficiency, and reducing the carbon-intensity of electricity demand.

Introduction

Global climate is warming primarily due to the accumulation of greenhouse gases in the atmosphere from human activities like burning fossil fuels (IPCC 2013). Regional warming and changing precipitation patterns can affect streamflow magnitude and timing (Elsner et al., 2010). Changes in streamflow magnitude, timing, and variability, as well as changes in energy demand, due to climate change can affect hydropower generation (Jiménez Cisneros et al. 2014; Hamlet et al., 2010).

With this awareness, Portland General Electric (PGE) is updating its evaluation of how climate change could affect electric demand and hydroelectric generation. This report summarizes the current science of global climate change as it pertains to the energy sector in the Pacific Northwest (PNW). It begins with a brief background on key climate science concepts, and then describes the modeling basis from which future climate projections are derived. The next sections summarize observed and projected changes in primary energy relevant climate variables and other climate variables of interest on both a global and regional scale. The final section summarizes global climate change mitigation options.

This report is the first of two tasks that the Oregon Climate Change Research Institute (OCCRI) will complete for PGE. In the second task, OCCRI will provide 21st century climate change projections based on the latest available data for the Portland metropolitan area to aid PGE with its planning analysis.

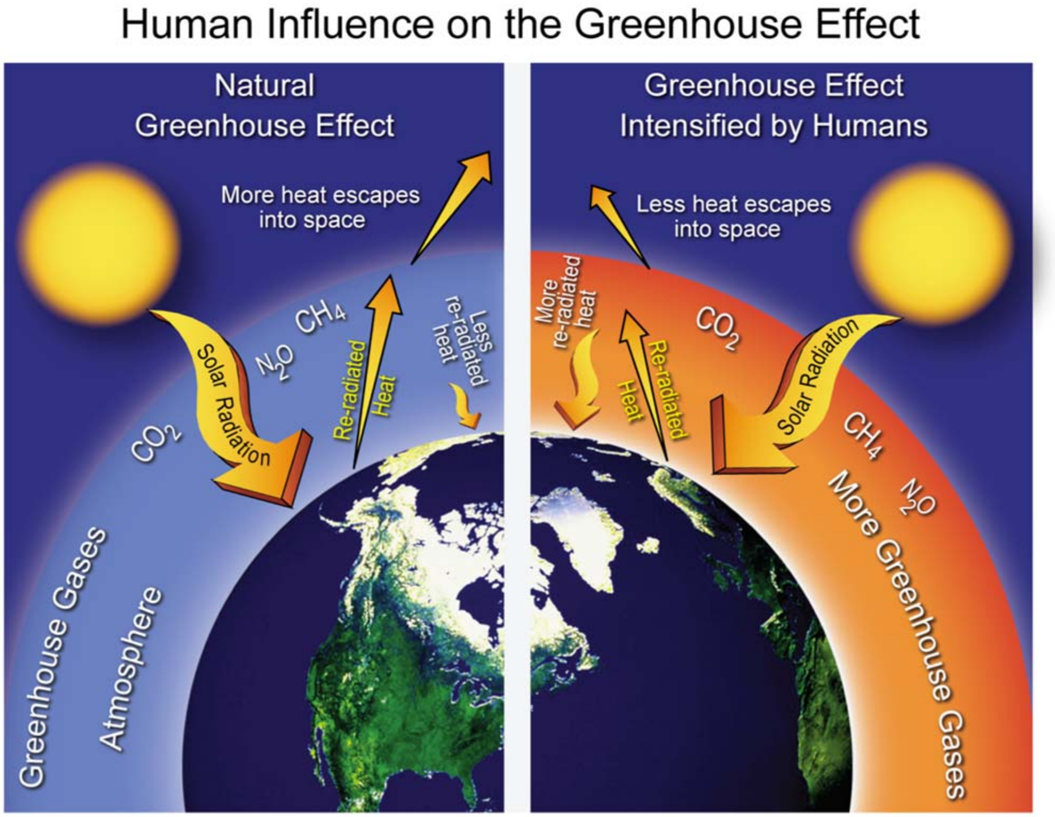
Climate Science Background

The Earth receives its energy from the Sun. The Earth's surface absorbs about half of this energy warming the surface. The rest of the energy is either reflected back out to space (30%) or absorbed by the atmosphere (20%). The heated surface then radiates heat back to space. Much of this heat is absorbed by naturally occurring greenhouse gases in the atmosphere, such as carbon dioxide, methane, nitrous oxide and water vapor. These gases emit energy in all directions, including back toward the surface, further heating the surface. This is known as the greenhouse effect and keeps the Earth at a livable temperature. Without it the average surface temperature of the Earth would be about 60 °F colder than it is at present.

When the Earth's temperature is stable over a long period of time, the Earth is said to be in equilibrium. That is, the amount of energy entering the Earth's climate system is equal to the amount of energy exiting the system. When a net amount of energy enters or exits the system over a period of time (i.e., the total radiative forcing is positive or negative), the Earth warms or cools.

Human activity intensifies the greenhouse effect through emissions of additional greenhouse gases to the atmosphere (Figure 1) largely through the burning of fossil fuels. With more greenhouse gases in the atmosphere, more of the heat emitted by the Earth's surface is absorbed in the atmosphere and radiated back to the Earth's surface, and less heat escapes into space. The net result is more heat trapped in the climate system, which steadily raises the Earth's average temperature.

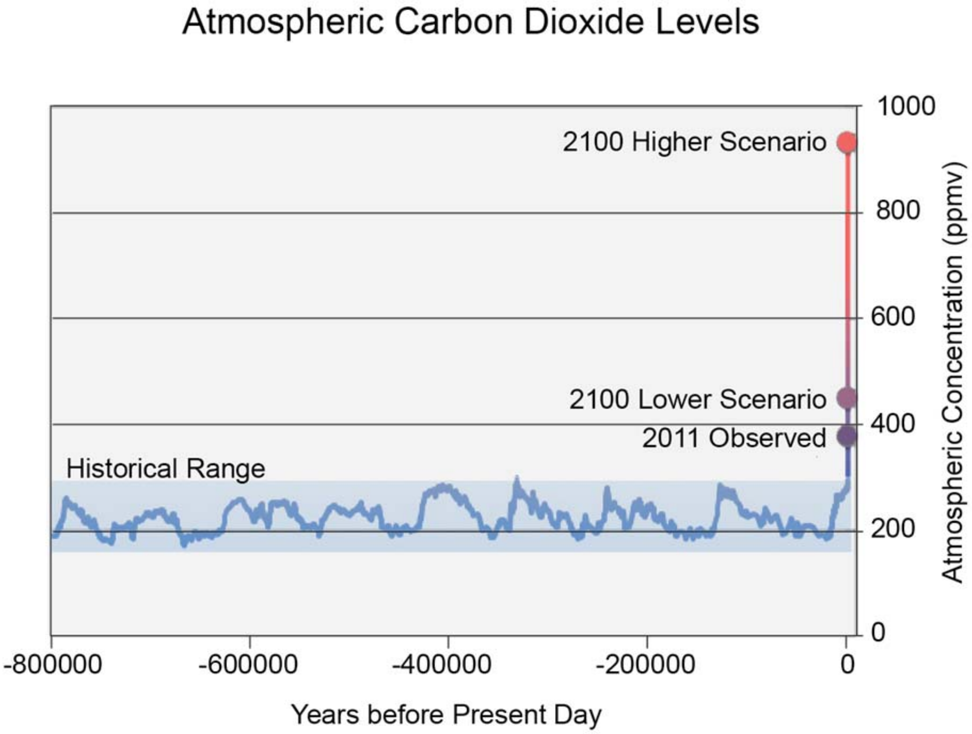
Figure 1 The Natural Greenhouse Effect Intensified by Human Influence. (Source: Walsh et al., 2014a)



Several natural and human factors influence the total radiative forcing on the Earth's climate system. On millennial time scales, variations in Earth's orbit govern the beginning and end of glacial periods. Throughout Earth's history, temperature and atmospheric carbon dioxide concentrations fluctuated together in and out of glacial periods (Figure 2). Cyclical variations in solar output on an 11-year cycle can increase or decrease the amount of energy the Earth receives either acting to increase or decrease the Earth's temperature. Episodic large volcanic eruptions that spew tiny sunlight-reflecting particles into the upper atmosphere can reduce the amount of solar energy reaching the surface acting to cool the planet for up to a couple years afterward.

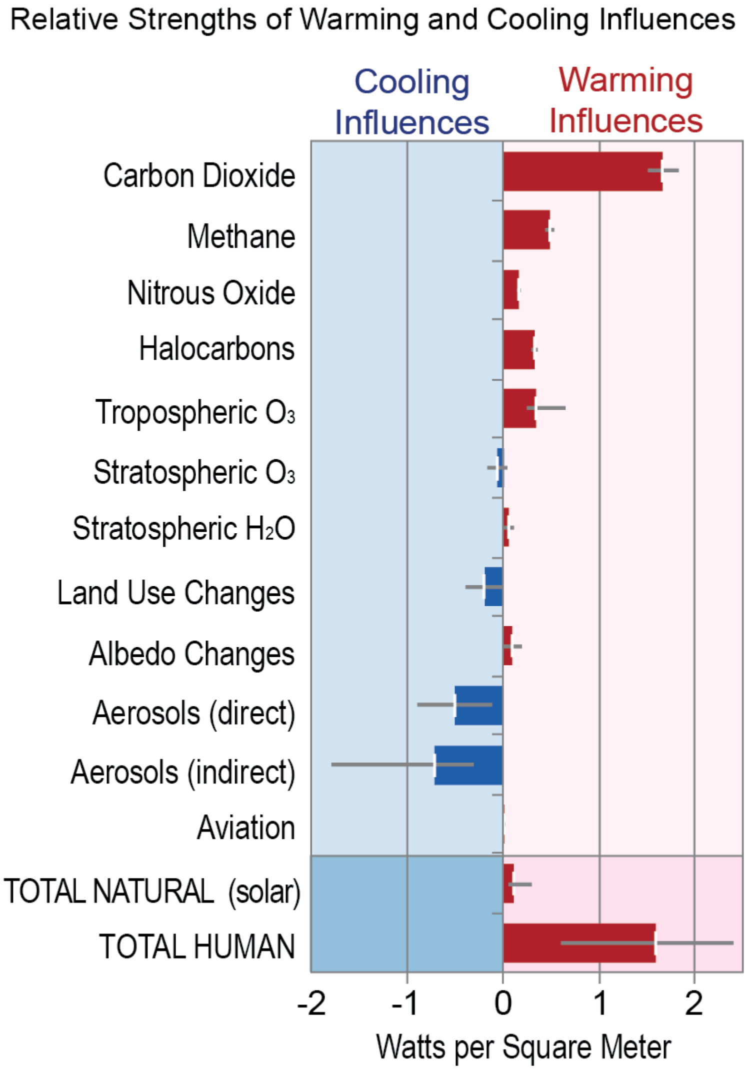
Since the Industrial Revolution, carbon dioxide and other greenhouse gases have been accumulating in the atmosphere and is the dominant factor responsible for the warming observed in the last half century. In 2013, the atmospheric concentration reached 400 parts per million, exceeding what the Earth has experienced for at least the last one million years; and concentrations are expected to continue rising throughout the 21st century to well beyond the historical range (Figure 2; Walsh et al., 2014a).

Figure 2 Atmospheric carbon dioxide levels in the historical record and for future lower (RCP2.6) and higher (RCP8.5) emissions scenarios (Source: Walsh et al., 2014a)



Changes in the reflectivity of the Earth's surface (i.e., albedo) due to land use change or melting ice cover can act to either cool or warm the planet. Tiny particles from pollution, including soot and sulfate particles, can reflect sunlight and interact with clouds to exert an overall cooling effect on the climate system. When adding all these factors together, the net result is a positive radiative forcing, dominated by increases in carbon dioxide and other greenhouse gases, currently acting to warm the planet (Figure 3).

Figure 3 Warming or cooling influences of all major human-induced factors and the only major natural factor (solar) with a long-term effect on climate in terms of change in radiative forcing in watts per square meter by 2005 relative to 1750. (Source: Walsh et al., 2014a)

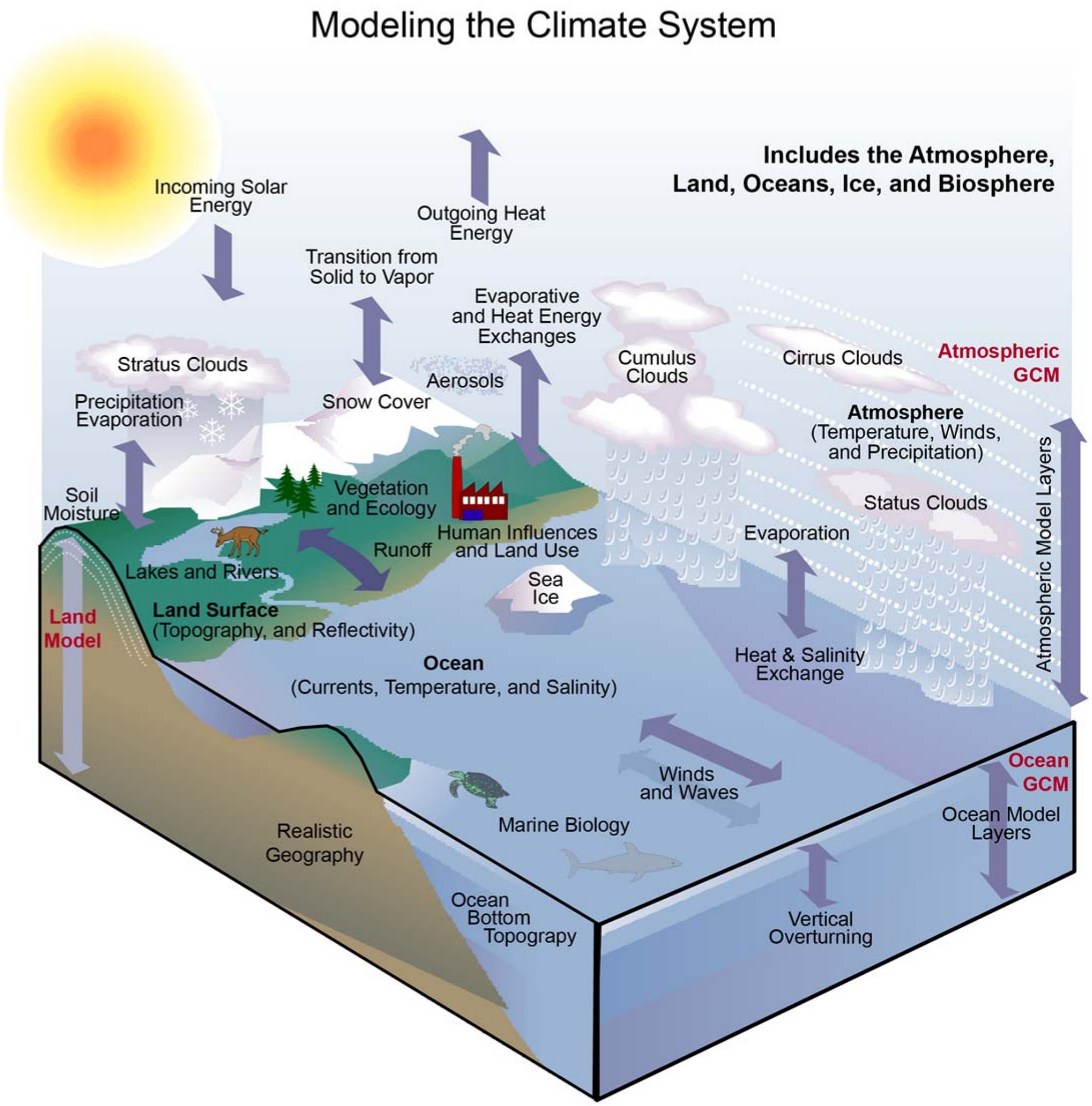


Modeling Future Climate

Global Climate Models

Global climate models (GCMs) are mathematical representations of the physics, chemistry, and biology of the Earth system. GCMs divide the Earth into grid cells of about 100 miles per side and solve fundamental equations of how mass, momentum, and energy are exchanged within the climate system. GCMs simulate atmospheric and ocean circulation, land surface processes, clouds, atmospheric chemistry, aerosols, land and sea ice, vegetation, and carbon cycling (Figure 4) (Walsh et al., 2014a).

Figure 4 Some of the many processes often included in models of the Earth's climate system. (Source: Walsh et al., 2014a)



Future climate projections summarized in this report are based on twenty state-of-the-art GCMs from the Coupled Model Intercomparison Project phase 5 (CMIP5; Taylor et al., 2012) that were used in the latest fifth assessment report of the Intergovernmental Panel on Climate Change (IPCC). Where CMIP5-based projections do not yet exist for the Pacific Northwest (e.g., streamflow), projections are based on the previous generation of models (CMIP3). The local climate change projection data that OCCRI will provide to PGE is based on CMIP5 whereas the streamflow projection data is based on CMIP3. (Streamflow projections based on CMIP5 will be publicly available in 2016 as part of a Bonneville Power

Administration project in which OCCRI is involved.) Table 1 lists the GCMs from both CMIP3 and CMIP5 that are used in this project.

Table 1 The 20 CMIP5 and 10 CMIP3 GCMs used in this project. Climate projections (e.g., temperature and precipitation) are based on CMIP5 whereas streamflow projections are based on CMIP3.

Model Name	**Ensemble**	**Modeling Center**
BCC-CSM1-1	CMIP5	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	CMIP5	
BNU-ESM	CMIP5	College of Global Change and Earth System Science, Beijing Normal University, China
CanESM2	CMIP5	Canadian Centre for Climate Modeling and Analysis
CCSM4	CMIP5	National Center for Atmospheric Research, USA
CCSM3	*CMIP3*	
PCM	*CMIP3*	
CNRM-CM5	CMIP5	National Centre of Meteorological Research, France
CNRM-CM3	*CMIP3*	
CSIRO-Mk3-6-0	CMIP5	Commonwealth Scientific and Industrial Research Organization/Queensland Climate Change Centre of Excellence, Australia
ECHAM5/MPI-OM	*CMIP3*	Max Planck Institute for Meteorology, Germany
ECHO-G	*CMIP3*	Meteorological Institute of the University of Bonn, Germany; Institute of KMA, Korea; Model and Data Group
GFDL-ESM2G	CMIP5	NOAA Geophysical Fluid Dynamics Laboratory, USA
GFDL-ESM2M	CMIP5	
HadGEM2-CC	CMIP5	Met Office Hadley Center, UK
HadGEM2-ES	CMIP5	
HadCM3	*CMIP3*	
HadGEM1	*CMIP3*	
INMCM4	CMIP5	Institute for Numerical Mathematics, Russia
IPSL-CM5A-LR	CMIP5	Institut Pierre Simon Laplace, France
IPSL-CM5A-MR	CMIP5	
IPSL-CM5B-LR	CMIP5	
IPSL-CM4	*CMIP3*	
MIROC5	CMIP5	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM	CMIP5	
MIROC-ESM-CHEM	CMIP5	
MIROC3.2(medres)	*CMIP3*	
MRI-CGCM3	CMIP5	Meteorological Research Institute, Japan
MRI-CGCM3.1(T47)	*CMIP3*	
NorESM1-M	CMIP5	Norwegian Climate Center, Norway

Emissions Scenarios

Simulations of the 21st century climate are driven by several plausible scenarios of future greenhouse gas emissions based on how fast population grows, how the economy evolves, what energy sources will be used, and what technological advances are implemented (Walsh et al., 2014a). In the CMIP3 ensemble (used in PGE's 2006 climate change study and for streamflow projections in this study), future climate simulations are driven by a set of greenhouse gas emissions scenarios developed for the climate modeling community in the 2000 Special Report on Emissions Scenarios (SRES). SRES scenarios were designed around a set of consistent assumptions about how the world's society will evolve (Nakićenović et al., 2000; see Table 2). The SRES scenarios are bounded by B1 (low emissions scenario representing a global economy becoming less resource intensive) and A1FI (high emissions scenario representing fossil intensive rapid global economic growth). The 2006 study used B1 and A2 and the streamflow projections in the current report rely on B1 and A1B.

Table 2 Description of RCP and SRES emissions scenarios with comparable analogs. Shaded scenarios are used in this project. (Nakicenovic et al., 2000; van Vuuren et al., 2011; Walsh et al., 2014a)

Scenario	Analog	Description
RCP2.6	None	Low forcing scenario peaking at 3 watts per square meter, then declining to 2.6 watts per square meter and achieving net negative carbon dioxide emissions by 2100.
RCP4.5	SRESB1	Medium forcing scenario representing moderate effort to curb carbon dioxide emissions with reductions during the second half of the century and achieving 4.5 watts per square meter radiative forcing by 2100.
RCP6.0	SRESA1B	Medium forcing scenario with emissions peaking around 2080 and achieving 6.0 watts per square meter radiative forcing by 2100.
RCP8.5	SRESA1FI	High forcing scenario representing business-as-usual continuation of emissions with rising radiative forcing leading to 8.5 watts per square meter by 2100.
SRESB1	RCP4.5	Low emissions scenario. Population peaks in mid-century, global economy shifts away from material intensity toward service and information with an introduction of clean, resource-efficient technologies.
SRESB2	None	Medium-Low emissions scenario. Continuously increasing population with regional intermediate economic development toward environmental sustainability.
SRESA2	None	High emissions scenario. Heterogeneous world with continuously increasing population and regionally oriented relatively slower economic growth.
SRESA1T	None	Low emissions scenario with rapid economic growth, population peaking at mid-century, and rapid introduction of new and more efficient energy technologies that are predominantly non-fossil.
SRESA1B	RCP6.0	Medium emissions scenario with rapid economic growth, population peaking at mid-century, and rapid introduction of new and more efficient energy technologies that are balanced across energy sources.
SRESA1FI	RCP8.5	Very high emissions scenario with rapid economic growth, population peaking at mid-century, and rapid introduction of new and more efficient energy technologies that are fossil intensive.

The CMIP5 climate models were driven by a new set of scenarios developed in 2010 called "representative concentration pathways" (RCPs) that define concentrations of greenhouse gases, aerosols, and chemically active gases leading to set amount of radiative forcing, or extra energy trapped in the earth-atmosphere system, by the year 2100 (van Vuuren et al., 2011). The RCP scenarios are bounded by RCP2.6 (achieving net negative carbon dioxide emissions before the end of century) and RCP8.5 ("business-as-usual" continuation of emissions). In this report, 21st-century climate projections are based on RCP 8.5 and a second scenario that assumes moderate efforts to curb emissions (RCP 4.5) (Figure 5). While no one scenario is considered more likely than another, our current trajectory of emissions places us nearer to RCP8.5 (Figure 6).

Figure 5 Carbon emissions and atmospheric carbon dioxide concentrations for SRES and RCP scenarios (Source: Walsh et al., 2014a)

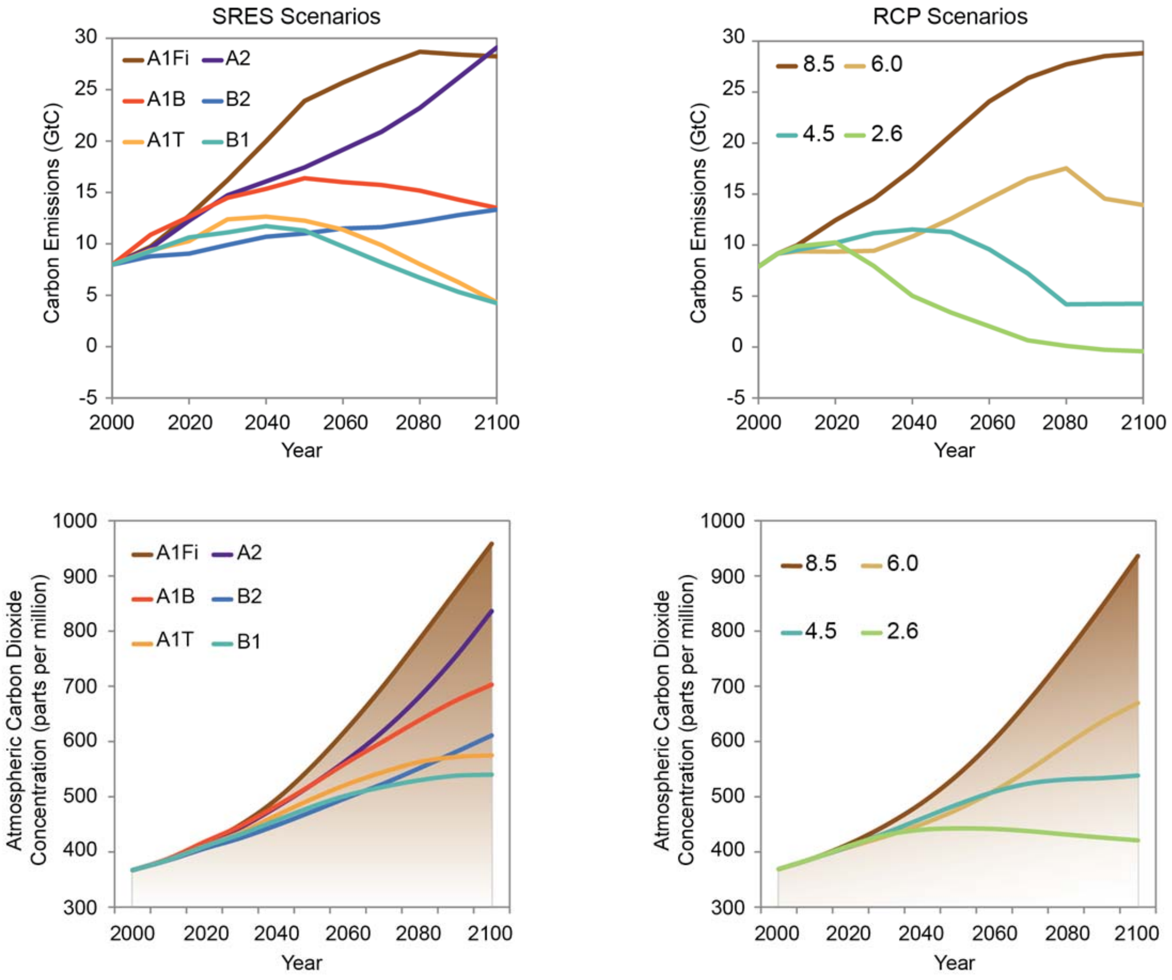
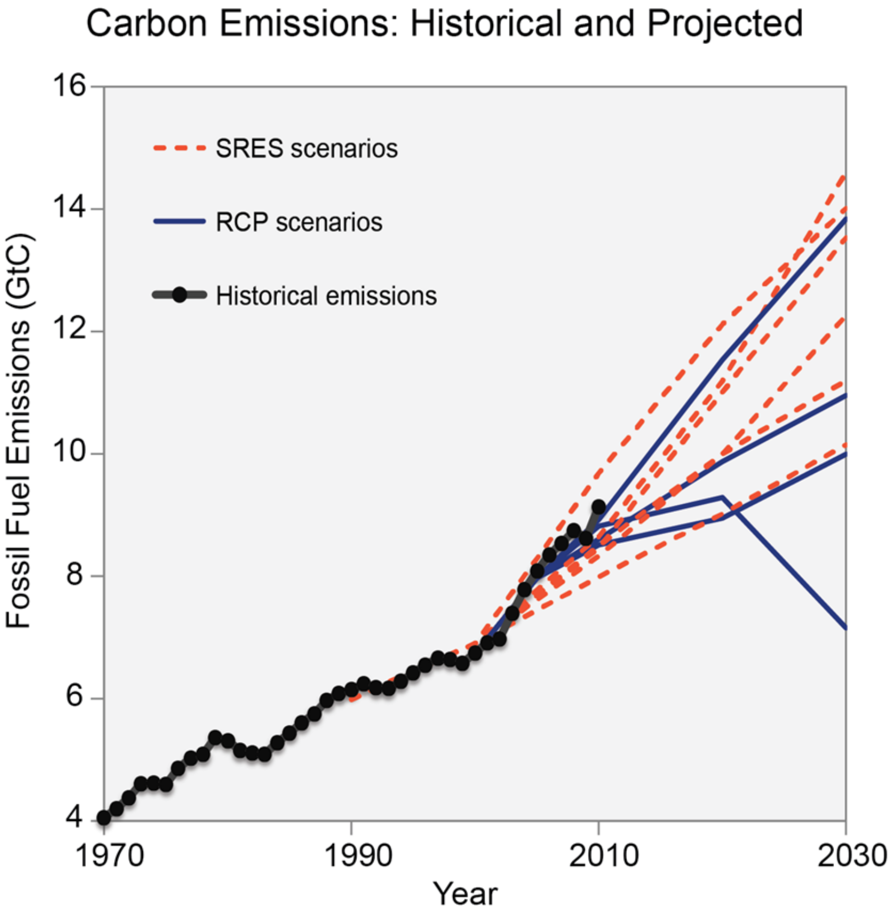


Figure 6 Observed historical and projected future SRES and RCP carbon emissions from 1970 to 2030 (Source: Walsh et al., 2014a)



Downscaling

Climate impacts analyses often require information at a higher resolution than current GCMs are able to provide. Downscaling, either statistically or dynamically, is used to translate coarse resolution GCM projections to more local scales.

Dynamical downscaling typically involves using output from GCMs as the boundary inputs for regional climate models (RCMs). RCMs simulate the same physical processes as GCMs, but at a higher resolution and over a smaller region. Dynamical downscaling efforts in the Pacific Northwest are achieving spatial resolutions ranging from 15 km to 50 km. RCMs can better simulate interactions of climate with topography, particularly important for the spatial patterns of precipitation changes within the complex topography of the Pacific Northwest. RCMs can also simulate small-scale feedbacks such as the snow-albedo feedback important for more accurate projections of spatial warming patterns across the region. However, RCMs are computationally expensive and inherit the same uncertainties and biases as GCMs. Additional uncertainty arises due to how the boundary conditions from the GCM are applied to the RCM and to estimation of physical processes at scales smaller than the RCM's resolution.

Statistical downscaling is achieved through using observed statistical relationships between large-scale atmospheric circulation patterns and local climate. Statistical downscaling is computationally less expensive than dynamical downscaling. It also effectively removes any biases between the historical simulations and the observations used to achieve the downscaling resulting in a good match between the average statistics of observed and statistically downscaled data over the historical record (Walsh et al., 2014a). Dynamical downscaling often requires an additional bias-correction step. There are several methods of statistical downscaling ranging from the simple "delta-method" (in which the change between the future and historic simulated climate is added to the observed record) to more sophisticated methods of spatial pattern matching of historical weather analogs (Walsh et al., 2014a). Statistical downscaling can be done to the scale of observations already used in existing planning processes. A limitation of all statistical downscaling technique is the assumption that historical relationships between large and small scales remain unchanged under future climate conditions, which may unjustly constrain relationships in a changing climate, particularly precipitation extremes (Walsh et al., 2014a).

The localized climate change projection data that will be delivered to PGE in Task 2 is based on the CMIP5 GCMs that have been statistically downscaled using the sophisticated Multivariate Adaptive Constructed Analogs (MACA) technique. The MACA approach utilizes a gridded training observation dataset to accomplish the downscaling by applying bias-corrections and spatial pattern matching of observed large-scale to small-scale statistical relationships and has demonstrated skill in complex terrain (Abatzoglou and Brown, 2012). The resulting downscaled data is available on a 6-km grid over the continental US at the daily time step from 1950-2099 for twenty GCMs (Table 1) and two RCPs (RCP4.5 and RCP8.5).

Uncertainty

Inherent in GCM projections is uncertainty due to emissions scenario, internal variability, and modeling physics and resolution. Given the same driving scenario of greenhouse gases, individual GCMs project different magnitudes of warming because the models' "climates" are either more or less sensitive to external radiative forcings (e.g., increasing greenhouse gases). The largest source of uncertainty in estimates of climate sensitivity is the representation of clouds in the modeled atmosphere (Boucher et al., 2013). Furthermore, the chaotic nature of the climate system means that even a single climate model, if identical simulations were started on a different day, yields a range of outcomes. Even at 100-mile horizontal resolution most GCMs are still unable to resolve key topographical features that influence western US climate.

Precipitation projections are generally more uncertain than temperature projections. Temperature projections, while models may vary on the magnitude, are highly robust since all models agree on warming under increasing greenhouse gases. Modeling accurate microphysical cloud processes that produce precipitation requires resolutions much finer than current GCMs can attain so most of those processes are estimated (i.e., parameterized), resulting in inherent uncertainty in precipitation projections. There is no consensus among the GCMs on the sign of future precipitation change as some models project increases and others decrease (Mote et al., 2013).

Primary Energy Relevant Variables

Temperature

Observed Trends

The Earth's surface warmed on average about 1.5°F between 1880 and 2012 (IPCC 2013). Similarly, the Pacific Northwest warmed on average at a rate of about 1.0°F to 1.4°F per century depending on the start year between 1901 and 1960 through 2012 (Abatzoglou et al., 2014). Warming was observed during all seasons, but most markedly in the winter in the Pacific Northwest (Abatzoglou et al., 2014). The observed temperature increase globally and regionally can be largely explained by rising greenhouse gases. The year-to-year fluctuations in temperature are controlled largely by natural modes of variability (e.g., El Niño-Southern Oscillation and the Pacific North American pattern), which acted either to enhance or counteract the long-term anthropogenic warming trend at different times and in different seasons (Abatzoglou et al., 2014).

Consistent with global warming, the frequency of cold days and nights has decreased while the frequency of warm days and nights has increased across the globe (IPCC 2013). In the Pacific Northwest, the temperature of the coldest day of the year exhibited a strong positive trend of more than 1.8°F (1.0°C) per decade since 1970, but the temperature of the warmest day of the year has changed little (Abatzoglou et al., 2014). Similarly, in western Washington and Oregon, the frequency of extreme (exceeding the 99th percentile for June-September) nighttime minimum temperatures increased substantially since 1901, but not daytime maximum temperatures (Bumbaco et al., 2013).

Future Projections

With continued greenhouse gas emissions, the Earth's climate will continue to warm. By the end of the 21st century relative to the 1850-1900 average, it is likely that global warming will exceed 2.7°F (1.5°C) under RCP4.5 and exceed 3.6°F (2°C) under RCP8.5. In the near term (2016-2035 relative to 1986-2005), global warming will likely be in the range of 0.5°F to 1.3°F (0.3°C to 0.7°C). By mid-century (2046-2065 relative to 1986-2005) global warming is likely to be in the range of 1.6°F to 3.6°F (0.9°C to 2.0°C) for RCP4.5 and 2.5°F to 4.7°F (1.4°C to 2.6°C) for RCP8.5 (IPCC 2013). Furthermore, hot temperature extremes will become more frequent, cold temperature extremes less common, and heat waves will become longer and more frequent over most land areas (IPCC 2013).

In the Pacific Northwest, average surface air temperature is expected to rise throughout the 21st century increasing by 3°F up to 14°F (1.7°C to 7.8°C) by 2100 depending on model and scenario (Figure 7). Mid-century (2041-2070 relative to 1950-1999) projections for the high emissions scenario RCP8.5 indicate annual average surface air temperature increases (Figure 7) in the range of 3.1°F to 8.5°F (1.7°C to 4.7°C) with larger warming in summer (Table 3) (Mote et al., 2013). These new temperature projections for the Pacific Northwest are slightly higher than those from the high scenario (A2) in the 2006 study because 1) RCP8.5 has a greater forcing than A2, 2) the time period for “mid-century” is slightly later, and 3) the historical baseline average includes earlier decades.

Figure 7 Observed (1950-2011) and simulated (1950-2100) regional mean temperature for selected CMIP5 global models for two emissions scenarios. (Source: Mote et al., 2013)

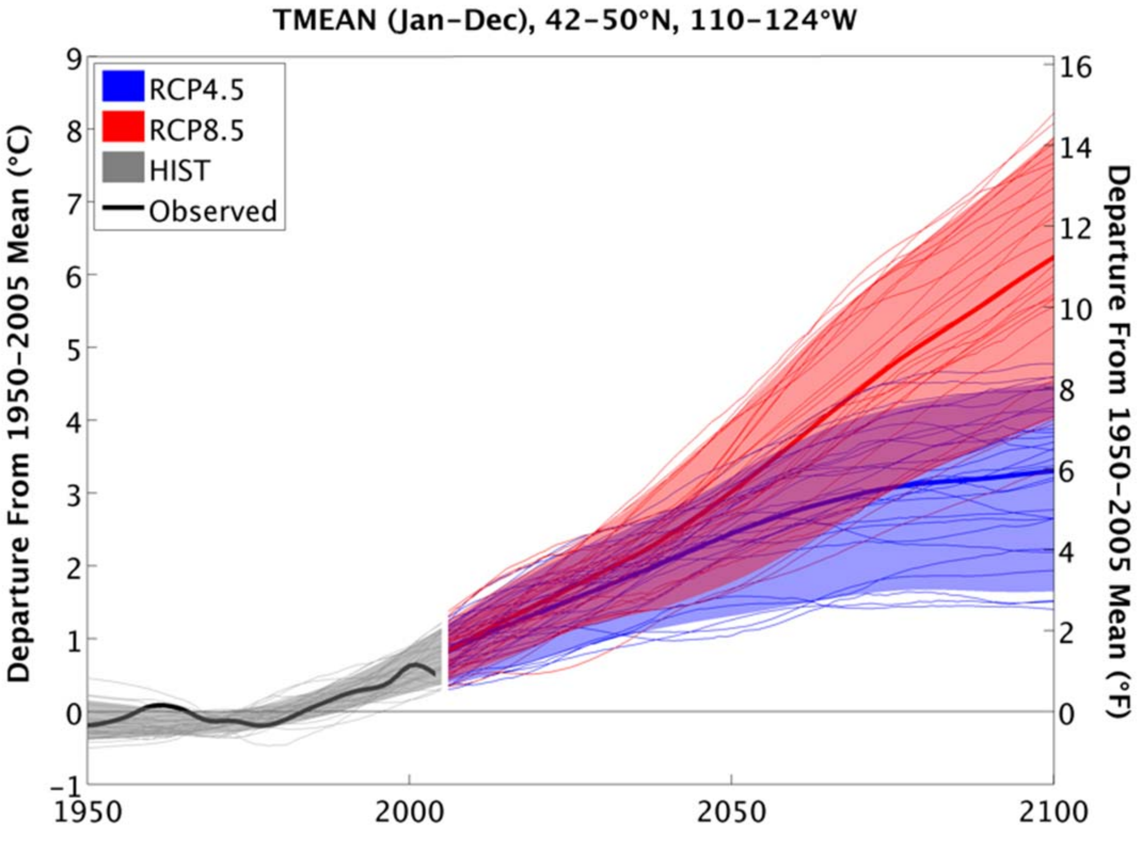
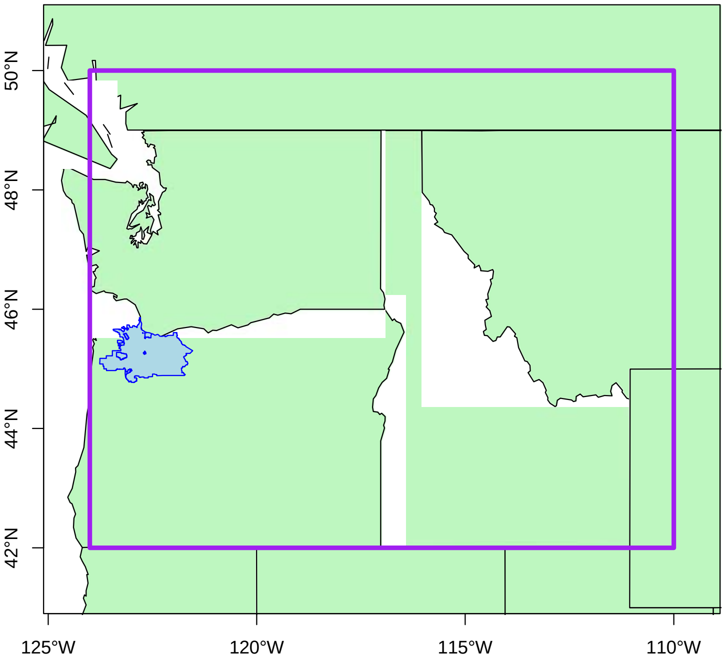


Table 3 Mean (and low and high range) of mid-century (2041-2070 relative to 1950-1999) temperature and precipitation projections for the Northwest under RCP 8.5. (Source: Mote et al., 2013)

	Temperature (°F)	Precipitation (%)
Annual	5.8 (3.1, 8.5)	3.2 (-4.7,13.5)
Winter	5.8 (2.3, 9.2)	7.2 (-10.6,19.8)
Spring	5.4 (1.8, 8.3)	6.5 (-10.6,26.6)
Summer	6.5 (3.4, 9.4)	-7.5 (-27.8, 12.4)
Fall	5.6 (2.9, 8.3)	1.5 (-11.0,12.3)

The climate change projection data for the PGE service territory (Figure 8) will be derived from twenty CMIP5 GCMs statistically downscaled with the MACA method (see description above). Downscaling is needed to bring the information from GCMs, which are at a coarse resolution of ~100 miles, down to a spatial resolution relevant to PGE's local energy production impacts analyses. From the statistically downscaled dataset, OCCRI will provide daily time series of maximum, minimum, and average temperature, precipitation total, mean wind speed, and mean specific humidity.

Figure 8 The PGE Service Territory (blue region) within the Pacific Northwest domain. Climate model data within the purple box was averaged to produce the region-wide climate projections presented in Table 3 and Figure 7.



Precipitation

Observed Trends

Changes in global and regional precipitation are dominated by natural variability. A clear signal of increased annual precipitation since 1901 was found averaging Northern Hemisphere mid-latitude land areas (IPCC 2013). Averaged over the Pacific Northwest, no clear trends in annual precipitation were found over the period 1901-2012, but a clear positive trend was noted in spring (Abatzoglou et al., 2014).

Globally, there are more areas in which heavy precipitation events have increased in frequency or intensity, such as North America, than where they have decreased. However, changes in precipitation extremes exhibited considerable spatial variability with some PNW locations experiencing increases in extreme precipitation and others decreases, depending on the metric evaluated (Mote et al., 2013).

Future Projections

From a global perspective, changes in precipitation in response to warming will manifest as a larger contrast between wet and dry regions and seasons, although there may be regional exceptions. In the near term, precipitation changes will largely reflect natural internal variability. By the end of the 21st century under the highest emissions scenario (RCP8.5), high latitudes and the equatorial Pacific Ocean are likely to experience an increase in annual mean precipitation. Mean precipitation is likely to decrease in many dry regions in the subtropics and mid-latitudes and increase in many mid-latitude wet regions (IPCC 2013). Where exactly that boundary between mid-latitude increases and decreases in precipitation is a little different for every model making precipitation projections difficult for the Pacific Northwest (Mote et al., 2013). However, a majority of models project increases in mean annual, winter, spring, and fall precipitation and decreases in summer, although the range of models includes both increases and decreases in every season (Table 3) (Mote et al., 2013).

Extreme precipitation events are very likely to become more frequent and intense over most land areas in the mid-latitudes and wet tropical regions by the end of the 21st century (IPCC 2013). In the Pacific Northwest, some measures of extreme precipitation are projected to increase (Mote et al., 2013), such as the magnitude of the 20-year and 50-year precipitation event, which is projected to increase by 10% (-4% to 22%) and 13% (-5% to 28%), respectively (Dominguez et al., 2012). The largest precipitation extremes are expected to increase proportionally more than the increase in the mean precipitation, as simulated in the region using GCMs (Rupp et al., 2014).

Streamflow

Changes in temperature and precipitation patterns have and will continue to alter the region's streamflow magnitude and timing with the potential to affect hydroelectricity supply. In the Pacific Northwest, mountain snowpack serves as a natural water reservoir feeding many rivers and streams during the dry season (April-September). Basins in the Pacific Northwest have been classified into three categories (Figure 9) based on the ratio of spring snow water equivalent (a measure of snowpack) to wet season (October-March) precipitation (Hamlet et al., 2013). Rain-dominant watersheds receive most of their precipitation as rainfall during the winter months and thus have streamflow peaks in winter and low flows in summer. Mixed rain-snow watersheds tend to have mean temperatures near freezing receiving both rain and snow, which produces a hydrograph with two peak flows, one in winter and one in late spring associated with spring snowmelt. Snow dominant watersheds receive most of their precipitation as snowfall and thus have their peak in streamflow during the late spring (Raymondi et al., 2013).

Observed Trends

Across the globe, most glaciers are receding and Northern Hemisphere spring snow cover extent is declining (IPCC 2013). Such changes in natural water storage, combined with local characteristics, have altered streamflow patterns in rivers worldwide (Hartmann et al., 2013). In the Pacific Northwest, warming temperatures are reducing the region's mountain snowpack. Averaged over the Cascade Mountains, April 1 snowpack decreased about 20% since the 1950s (Mote et al., 2014). In river basins that rely on mountain snowpack for a portion of streamflow, spring snowmelt occurred up to one month earlier and streamflow in the late winter/early spring increased up to 15% depending on location (Mote et al., 2014). The basins that have experienced the largest flow changes are those with mean temperatures near the freezing level (Hamlet et al., 2005). However, such changes largely affect headwaters as flow regulation has damped any climate change signal on streamflow below dams in the Columbia River Basin (Hatcher and Jones, 2013).

Future Projections

Widespread declines in April 1 snowpack are projected throughout the Columbia River Basin under future climate change. The largest changes in occur in locations with average winter temperatures within a few degrees of the freezing level, such as the Cascade Range and moderate elevations in the Rockies. Averaged over the Columbia River Basin, April 1 snowpack is projected to decline by -23% to -29% by the 2040s depending on future emissions scenario (SRESB1 or SRESA1B) (Hamlet et al., 2013). Watersheds that rely on snowpack as a natural reservoir for spring and summer water supplies are particularly sensitive to climate change. Some of the highest elevation snow-dominant watersheds are likely to remain, but many are likely to trend gradually toward mixed rain-snow watersheds characteristics (Figure 9). Mixed rain-snow watersheds are likely to trend gradually toward rain-dominant watershed characteristics (Figure 9) including earlier spring melt, reduced spring peak flows, increased winter flows, and reduced summer flows (Figure 10) (Raymondi et al., 2013). Mid-century projections indicate that snowmelt could occur three to four weeks earlier (Mote et al., 2014). Currently, about 75% of the state of Oregon is classified as mixed rain-snow (Figure 9), but by the end of the 21st century, nearly all of the state is projected to become rain-dominant (Hamlet et al., 2013).

Figure 9 The classification of PNW watersheds into rain dominant, mixed rain-snow, and snowmelt dominant and how these watersheds are expected to changes as a result of climate warming based on the SRESA1B emissions scenario (Source: Hamlet et al., 2013 reproduced in Dalton et al., 2013)

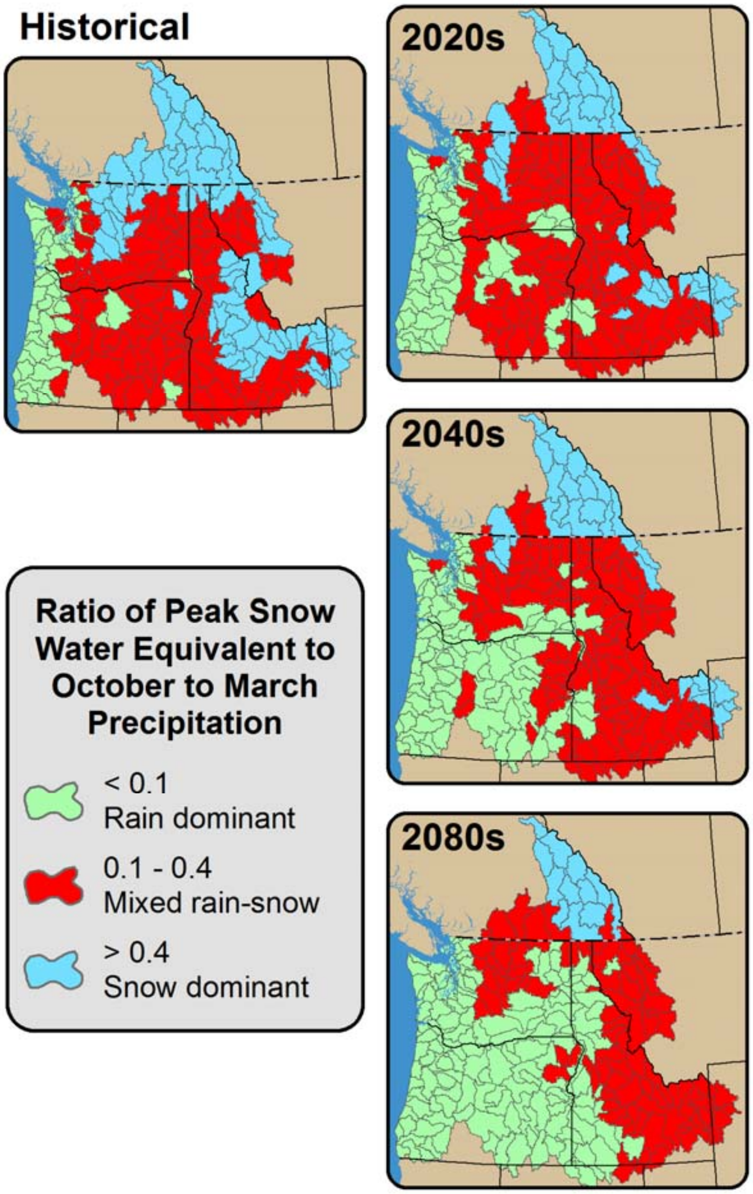
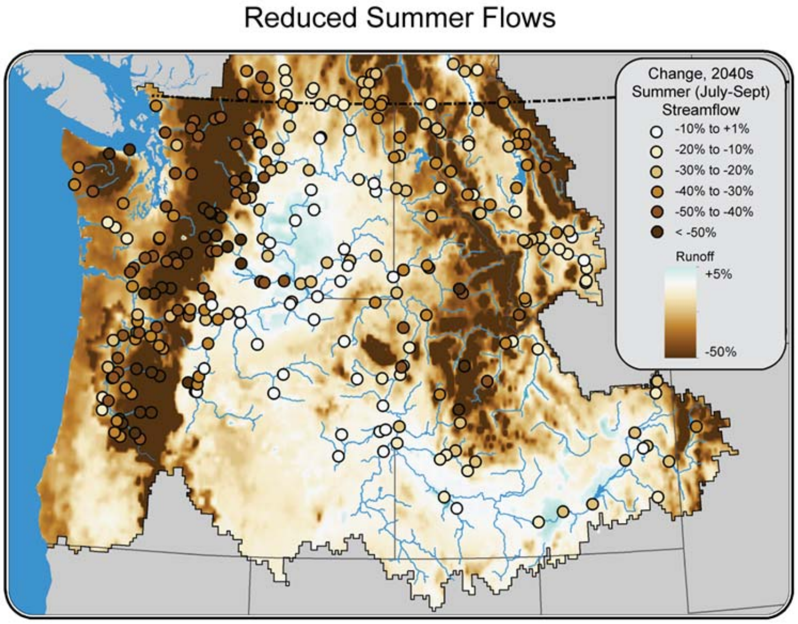
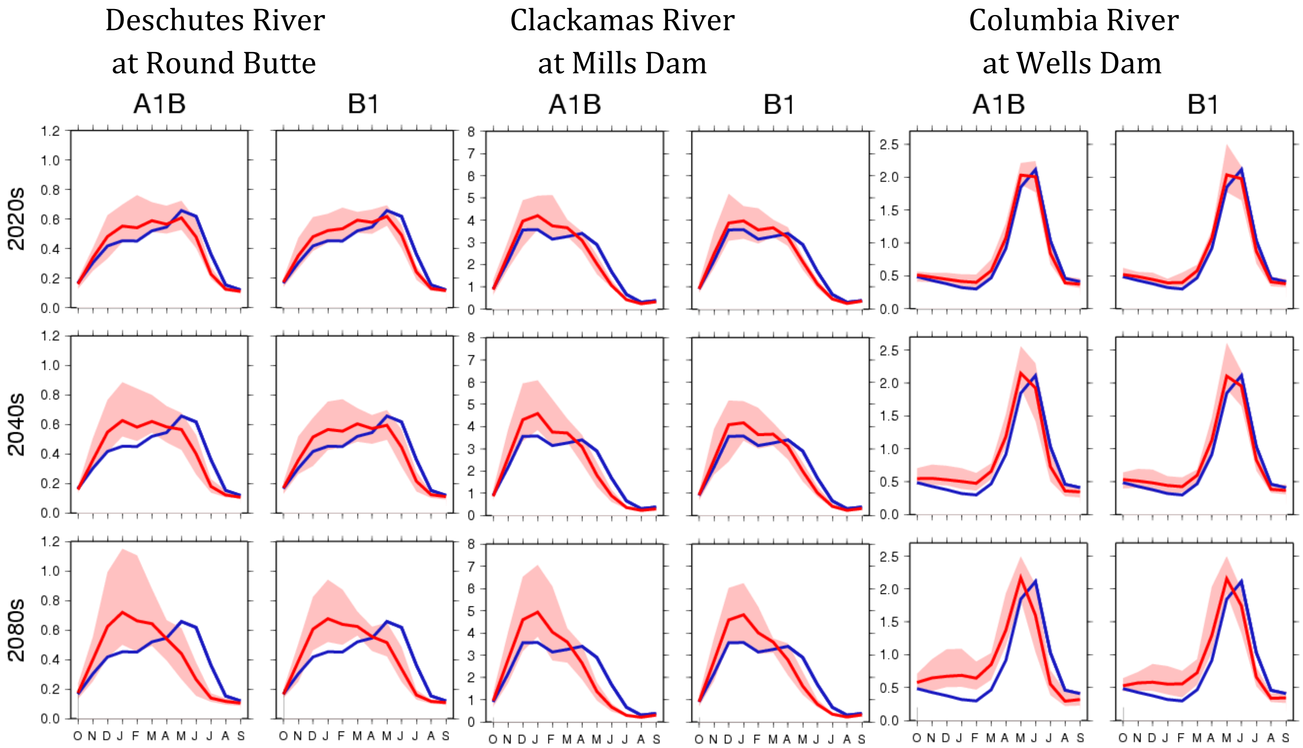


Figure 10 Changes in summer runoff and streamflow by the 2040s (Source: Mote et al., 2014).



Future changes in streamflow magnitude and timing for three sites of interest to PGE are shown in Figure 11. Deschutes River at Round Butte and Clackamas River at Mills Dam are both in mixed rain-snow watersheds that are projected to shift gradually toward more rain-dominant watershed characteristics. That is, winter peak flow is projected to increase, the spring peak flow decreases and summer flow decreases by the end of the 21st century (Figure 11). Columbia River at Wells Dam is in a snow-dominant watershed, which is projected to remain largely snow-dominant but shift slightly toward mixed rain-snow watershed characteristics. That is, winter flows are projected to increase and the spring peak is projected to shift earlier and summer flows are projected to decrease (Figure 11). These streamflow projections about based on CMIP3 climate projections; however, streamflow projections based on CMIP5 will be publicly available in 2016 as part of a Bonneville Power Administration project in which OCCRI is involved.

Figure 11 Projected change in combined monthly average total runoff and baseflow in inches (the primary determinants of streamflow) over the entire basin for the Deschutes River at Round Butte (left), Clackamas River at Mills Dam (center), and Columbia River and Wells Dam (right) for a low (B1) and medium (A1B) emissions scenario and three time periods (2020s, 2040s, 2080s). Blue line shows the simulated historical values. Red line shows the ensemble average of streamflow projections derived from 10 global climate models. The red shading shows the range across the 10 models. (Source: Columbia Basin Climate Change Scenarios Project, http://warm.atmos.washington.edu/2860/)



the 1950s and their tracks have generally shifted northward following the slight northward shift of the jet stream (Walsh et al., 2014b). However, on the Northwest coast of the US, including British Columbia, the slightly positive trend from 1948-2010 in extratropical winter storm frequency is not statistically significant (Vose et al., 2014). Future projections indicate a slight poleward shift in the jet stream, but there is as yet no consensus on whether or not extratropical storms will intensify or become more frequent under a warmer climate (Vose et al., 2014). Many of the flood-producing extreme precipitation events in the Pacific Northwest are associated with cool season (November-March) atmospheric river events, which tend to be warmer and rainier than typical extratropical storms. In contrast to extratropical storms, there is stronger evidence suggesting that atmospheric rivers are projected to become stronger and more frequent along the PNW coast (Warner et al., 2015).

Wind Speed

Over the ocean, mid-latitude westerly winds have generally increased, including along the west coast of North America. Over land, however, surface wind speeds have slowed in many areas in the tropics and mid-latitudes, including much of the United States (Hartmann et al., 2013). Over the Pacific Northwest, lower-tropospheric mean westerly wind speed during the cool season has decreased between 1950-2012 at a rate of 0.2 m/s per decade (Luce et al., 2013), However, confidence in observed trends in wind speed remain low due to observational limitations (Hartmann et al., 2013). In addition, evidence for observed changes in extreme winds is inconclusive over land (Vose et al., 2014).

From the NH sub-tropics to the pole, projected changes in wind speed at the surface are less than one standard deviation of the natural variability making a true climate change signal in surface wind speed difficult to detect even by the end of the 21st century (Collins et al., 2013). Over the Pacific Northwest, a majority of CMIP5 climate models project a decrease in cool season wind speed by the end of the century (Luce et al., 2013). In one study, summertime wind speeds were projected to decrease in the Northwest by mid-century corresponding to a reduction in summertime wind power generation potential of up to 40% (Sailor et al., 2008). No evidence is found for future changes in extreme winds over the western US (Pryor et al., 2012).

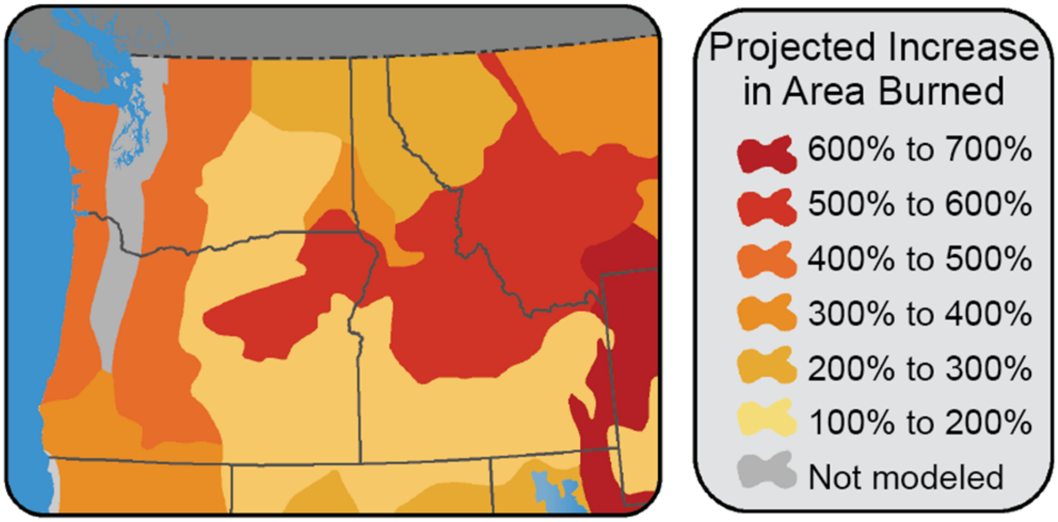
Cloud Cover

Global trends in cloud cover display ambiguity between different surface and satellite observation datasets. While cloud cover may have increased over many land areas, including the United States, since the mid-20th century (Hartmann et al., 2013), trends in recent decades suggest small decreases over the globe, United States, and Northwest (Sun et al., 2015). However, confidence in observed cloud cover changes remains low due to observational limitations. Future projections indicate that cloud cover will decrease in the subtropics and increase at high latitudes (Collins et al., 2013). Over the Pacific Northwest, model agreement on projected changes in cloud cover is low and natural variability still dominates the signal by the end of the century (Collins et al., 2013).

Wildfire Risk

Wildfires can pose a risk to electric transmission lines. Warmer and drier conditions have helped large fires become more frequent and increase total area burned across the West during the last 30 years (Dennison et al., 2014) and over the past century (Littell et al., 2009). The length of the fire season in the western US has also increased (e.g., Westerling et al. 2006). Such trends are expected to continue under future climate changes. One study estimated that the regional area burned per year will increase by roughly 900 square miles by the 2040s (Figure 12) with larger increases projected for the eastern Cascade Range and non-forested systems compared to the western Cascade Range (Littell et al., 2013). Furthermore, the probability of very large wildfires is projected to increase by at least 30% by the end of the century in the West (Stavros et al., 2014).

Figure 12 Increases in area burned that would result from the regional temperature and precipitation changes associated with a 2.2°F global warming across areas that share broad climatic and vegetation characteristic. Local impacts will vary greatly within these broad areas with sensitivity of fuels to climate. (Source: Mote et al., 2014)



Mitigation

Mitigation involves reducing the human contribution to the greenhouse effect by lowering emissions of carbon dioxide, methane, and other gases or particles that have a warming effect on the planet (Jacoby et al., 2014). Electric power generation and transportation are the main emitters of carbon dioxide in the US (Jacoby et al., 2014). The atmosphere, land, and ocean are natural reservoirs for carbon dioxide, but about half the carbon dioxide emitted by human activities in a year will be naturally removed from the atmosphere within a century. Twenty percent remains in the atmosphere, affecting climate for thousands of years (Jacoby et al., 2014).

Stabilizing global emissions will only limit the rate of increase of atmospheric concentrations (Jacoby et al., 2014). The global mean surface temperature responds to the cumulative total emissions of CO_2. To limit the Earth's warming to 2°C (3.6°F) compared with the period 1861-1880, with a 66% probability, cumulative C02 emissions from all anthropogenic sources must remain below 1000 GtC. High emissions in earlier decades would imply low emissions later. By 2011, 515 GtC have already been emitted (IPCC 2013 SPM). Under the existing RCP emissions scenarios, only RCP2.6 would achieve warming limited to 2°C by 2100; the other scenarios would exceed 2°C around mid-century.

Options to mitigate global emissions hinge on decarbonizing the world's energy use. In the electric sector, this can be advanced by using less CO_2 intensive fuel sources and using more carbon-free energy sources (e.g., hydropower, solar, wind, nuclear, etc.). Of the new electricity-generating capacity added in 2012, renewables accounted for half (IPCC 2014). Another side of mitigation is preventing emissions from reaching the atmosphere through carbon capture and sequestration. A third facet involves removing carbon dioxide from the atmosphere through means such as afforestation and bioenergy. Finally, decreasing electricity demand through increasing the efficiency of electricity use in all sectors and behavioral change is a key strategy (IPCC 2014). However, the transition of heating and transportation fueling toward lower carbon sources (e.g., biofuels and electricity for the transportation sector) as assumed under future emissions scenarios of significant decarbonization of the global economy (e.g., SRES B1 or RCP4.5) could potentially increase electricity usage (Jacoby et al., 2014).

Geoengineering involves planet-wide temperature management through solar radiation management (SRM) and carbon dioxide removal (CDR). These methods can carry side effects and long-term consequences on a global scale. Theoretically, SRM methods could offset a global temperature rise, but they would also modify the global water cycle and would not reduce ocean acidification. Furthermore, if SRM methods were terminated for any reason, temperatures would rise again, but at a much faster pace, making adaptation more challenging. Methods of CDR are feasible, but on a global scale they have biogeochemical and technological limitations. Furthermore, it is yet unknown just how much CO_2 emissions could be offset over a century (IPCC 2014).

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APPENDIX F. Distributed Generation Studies

PGE Distributed Solar Valuation Methodology (Clean Power Research)

Solar Generation Market Research (Black & Veatch)

Non-Solar Distributed Generation Market Research (Black & Veatch)

PGE Distributed Solar Valuation Methodology

July 13, 2015

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Executive Summary

This report lays out a methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) electric distribution system.

The methodology is concerned primarily with the benefits and costs of distributed solar generation, but can also be modified for use with utility scale resources (connected to transmission) by eliminating the avoided transmission and distribution costs benefits and removing the loss savings. Furthermore, the methodology can be used for other generation technologies other than solar, but it does not include dispatch strategies or other methods to produce an assumed generation profile (the profile is an input to the methodology).

The overall methodology is summarized in Figure ES-1 in which the benefit and cost categories are listed along with applicable load match factors and loss savings factors to arrive at the final value. For example, the Avoided Generation Capacity Cost is developed initially for a “perfect” (i.e., fully dispatchable) resource, and then a factor for the effective capacity (EC) is applied to account for the non-dispatchable nature of the resource. Finally a loss savings factor is applied since the resource is located adjacent to the load. Note that three different loss savings factors are employed, depending upon category. For example, the loss savings factor associated with Avoided Energy Cost (“LSF-Energy”) differs from the loss savings factor associated with effective capacity (“LSF-EC”). LSF-Energy would incorporate loss savings in all solar hours, while LSF-EC would be heavily weighted by the relatively few peak hours, depending upon the method selected for EC.

The method for calculating each component cost and benefit is described in this document, along with supporting methods, such as those needed to produce the underlying solar profiles and the method for calculating load match factors and loss savings factors.

Figure ES-1. Summary of Methodology

Levelized Value			Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	🟥	Avoided Fuel Cost	C1				LSF-Energy		V1
	🟥	Avoided Variable O&M Cost	C2				LSF-Energy		V2
	🟥	Avoided Fixed O&M Cost	C3		EC		LSF-EC		V3
	🟥	Avoided Gen. Capacity Cost	C4		EC		LSF-EC		V4
	🟥	(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission and Distribution	🟦	Avoided Trans. Capacity Cost	C6		EC		LSF-EC		V6
	🟦	Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
	🟦	Voltage Regulation	C8						V8
Environmental	🟪	Avoided Environmental Compliance	C9				LSF-Energy		V9
	🟪	Avoided SO_2 Emissions	C10				LSF-Energy		V10
Customer	🟩	Avoided Fuel Price Uncertainty	C11				LSF-Energy		V11
									Total

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Introduction

Overview

This report lays out a proposed methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) electric distribution system.

Distributed PV versus Utility Scale PV

The methodology presented here incorporates many techniques developed for evaluating distributed PV resources. However, PGE also has an interest in evaluating utility scale resources. To accomplish this objective, the more challenging and detailed methods of distributed systems will be developed first. The methodology then will include descriptions of how to adapt this method for utility scale.

The main areas of difference lie in the development of fleet production profiles and loss savings calculations.

Methodology Framework

The methodology described here is designed primarily for determining the benefits and costs of the gross energy produced by a PV system prior to netting with local load. Variants of this methodology could be used to determine the value of energy exported to the grid after netting local load, but the methods for calculating export energy (i.e., what assumptions to make about customer load shape and PV size relative to usage) are not included in this methodology. These considerations should be taken into account when applying this methodology in valuing energy provided by NEM systems.

The value of distributed solar is the sum of several distinct value components, each calculated separately using separate procedures. As illustrated in Figure 1, the calculation of each component includes an initial value, a component-dependent load-match factor (as applicable to account for solar intermittency) and a component-dependent Loss Savings Factor.

For example, the avoided generation capacity cost includes an initial value that is calculated based on a perfectly-dispatchable, centralized resource. This is then corrected to account for the non-dispatchability of solar by multiplying it by the effective capacity load match factor. Next, loss savings are included using a factor that is calculated using a method that corresponds to the effective capacity calculation. From these two adjustments, a distributed PV value is calculated for avoided generation capacity cost. Similar adjustments are applied, as applicable, to the other cost and benefit components.

Distributed PV Values are summed as shown in Figure 1 to give the levelized value denominated in dollars per kWh.

Figure 1. Overview of value calculation

		Levelized Value	Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	🟥	Avoided Fuel Cost	C1				LSF-Energy		V1
	🟥	Avoided Variable O&M Cost	C2				LSF-Energy		V2
	🟥	Avoided Fixed O&M Cost	C3		EC		LSF-EC		V3
	🟥	Avoided Gen. Capacity Cost	C4		EC		LSF-EC		V4
	🟥	(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission and Distribution	🟦	Avoided Trans. Capacity Cost	C6		EC		LSF-EC		V6
	🟦	Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
	🟦	Voltage Regulation	C8						V8
Environmental	🟪	Avoided Environmental Compliance	C9				LSF-Energy		V9
	🟪	Avoided SO_2 Emissions	C10				LSF-Energy		V10
Customer	🟦	Avoided Fuel Price Uncertainty	C11				LSF-Energy		V11
									Total

Applicability to Non-solar Technologies

Many of the techniques included in this methodology have historically been developed for evaluating solar resources; however PGE also has an interest in using these for non-solar technologies, such as CHP, microturbines, fuel cells, and energy storage. With this in mind, the methodology is intended to be technology neutral and applicable to all distributed generation technologies.

Each technology has a different production profile. While the solar profile ramps up and down over the course of the day, the microturbine is a dispatchable resource and its profile is therefore user-defined. For example, a customer-owned microturbine may be operated to maximize bill savings based on the customer's load profile and the rate schedule.

Regardless of technology, the technical and economic methods described here may be used. For example, if a dispatchable distributed microturbine is used, the effective capacity would be calculated using the same load match factors for distributed solar (see "Load Match Factors"). The result would be expected to be considerably higher for the microturbine than for solar, but the method is the same.

For example, Figure 1 shows that the Avoided Distribution Capacity Costs includes the gross value "C7." The value of C7 would be the same regardless of technology, calculated as described in the Avoided Distribution Capacity Cost section. However, the calculation of the load match factor "PLR" would be different for a microturbine versus a distributed solar resource. Both calculations would be based on the same method—see the method described in the Peak Load Reduction section—but the numerical result would be different. The resulting Loss Savings Factors "LSF-Dist" would also be slightly different for microturbines versus solar resources but would each be calculated using the same equation (4).

As an example, suppose that gross value C7 was $0.01 per kWh, PLR was determined to be 100% and 10% for the microturbine and solar, respectively, and LSF-Dist was 10% and 9% for the microturbine and solar, respectively. The resulting distributed PV values would be $0.01 x 1 x 1.10 = $0.011 per kWh and $0.01 x 0.1 x 1.09 = $0.00109 per kW, respectively.

Utility Avoided Costs

Figure 1 identifies costs and benefits of distributed solar that accrue to the utility and its customers. However, there may be other important societal benefits that are not included in this list. These are described more fully in the Societal Benefits section.

Methodology Objectives

The value of generated energy for each distributed PV system will differ because each system is a unique combination of many factors, such as:

- Irradiance patterns and shading at PV system geographical coordinates
- PV system orientation, such as the azimuth and tilt angle that define the daily generation profile
- Interconnection point of PV system on the transmission and distribution system
- Conductor sizing on local feeder

To calculate the value for each system would be highly impractical. Instead, it is useful to calculate average values for a defined group, such as for all distributed PV in the PGE service territory.

There is a natural tension between transparency and complexity of analysis. The intent of this methodology is to balance these two competing objectives as best as possible. For example, to evaluate avoided utility losses, every PV system could be modeled on the distribution system based on electrical location, wire size, regulator settings, and other modeling details. While this would provide the most satisfying engineering estimates, it is not practical from the standpoint of transparency because other stakeholders do not have access to the physical circuit models or the detailed device data that accompanies them. Implementing such a methodology would also be prohibitively costly. Therefore, a simplifying assumption employed here is to model the distribution system as a single component with single loss-versus-load curve rather than modeling each circuit separately.

Note that the methodology described here could be applied at varying levels of granularity. For example, the method could be applied at the level of the distribution circuit. This would require additional detail in input data (e.g., obtaining loss factors, hourly loads, and solar production profiles unique to each circuit). Such an analysis would result in the costs and benefits of distributed PV at the circuit level. It would be up to PGE to decide what level of granularity would be appropriate.

Marginal Fuel

This methodology calculates energy value as the avoided cost of fuel and O&M, assuming that PV displaces natural gas during PV operating hours. During some hours of the year, other fuels may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption.

Lumpiness of Capital Investments

Capacity-related investments by PGE, whether for generation, transmission, or distribution, are planned such that the required capacity is installed and put into service in time to meet anticipated loads. This methodology implicitly assumes that DG is also installed and put into service in time to meet the same loads. It is not necessary that all DG is installed in a single year, but the cumulative capacity has to be sufficient to avoid the investment.

PGE Economic Analysis Period and Residual Value

PGE has set the analysis period for the Solar Generation Market Research work at 20 years. This period will largely overlap with the useful service life of PV, but not necessarily entirely. If the useful service life of PV is, for example, 25 years, then the selection of 20 years would capture only the first 20 years of value. PGE suggests incorporating “residual” value to account for the difference between service life and study period.

To accomplish this objective in the methodology, the following procedure is used. First, PGE will make an assumption about the PV service life. If the decision is made to adopt 20 years, then there is no residual value. If it is less than 20 years, then the analysis period should be set to the service life because no additional costs or benefits will be realized in the years that follow the service life. Finally, if PGE adopts a life assumption greater than 20 years (e.g. 25 years), then the methodology should be run twice: once with the service life and once with the study period. The difference in results should be added as another benefit category entitled “Residual Value.” Since the assumption is not known at this time, Residual Value is not shown explicitly in the summary chart in Figure 1.

PGE Assumptions and Sensitivities

This methodology does not propose specific input assumptions to perform the VOS calculations. These assumptions would largely be developed by PGE or other sources as a preliminary to conducting the VOS study. Therefore, the methodology is intended to treat assumptions as variables, although in some cases example values are used to illustrate calculation methods.

A VOS study may include, if desired, sensitivities to the input assumptions. For example, the PV degradation rate may be selected for the baseline assumption as 0.5 percent per year, but sensitivity runs may be performed using other values. The sensitivity runs would use the same methodology, but just incorporate different assumptions.

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective capacity (EC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation.

To ensure that the solar modeling is time-correlated with load, a historical "Load Analysis Period" must be selected over which the technical parameters are calculated. To account for seasonal variations, a minimum of one year is required. The Load Analysis Period may be lengthened (e.g., 3 years) if desired, to account for annual differences.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy, taking into account losses internal to the PV system. This is in contrast to DC rating conventions based on Standard Test Conditions (STC). All PV capacity under this study is calculated by multiplying the DC rating by an STC-to-PTC derate factor,[1] by an inverter loss factor, and by an "other losses" factor. Typical assumptions might be 90%, 95%, and 85%, respectively, so the overall DC to AC derate factor using these assumptions would be 0.90 x 0.95 x 0.85 = 0.73, or 73% of the DC rating at standard test conditions.

The rating convention described above is one of several possible conventions used in the industry. The DC-STC rating convention is common (the DC-STC module rating times the number of modules), and it is easy to apply because the ratings are readily available from the module manufacturer. Another common convention is an "AC" rating calculated as the DC-STC rating times the STC-to-PTC derate factor times the load-weighted inverter efficiency. This is also relatively easy to implement because these factors are available from the module and inverter manufacturer. However, such a rating does not include system-level losses, such as the voltage-current mismatch between modules and strings. Such losses are specific to the system design and are therefore more difficult to obtain for each system individually. The above approach therefore makes an assumption of these other losses based on typical system performance.

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[1] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC rating allows modules to come to steady state temperatures with external conditions of 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level.

The rating convention is somewhat arbitrary; however PGE should be internally consistent when describing PV capacity. For example, when calculating the EC percentage, the result will differ if using AC or DC rating conventions. Similarly, when discussing future MW penetration levels, the rating convention should be clearly stated.

PGE PV Fleet Production Profiles

PV Fleet Production Profiles on an hourly basis over the Load Analysis Period will be developed using the method that follows. Note that the VOS is to be developed for future, as yet unbuilt resources, and that existing resources are used as a proxy for these systems. The existing systems serve as the best available data because they are found in locations (such as population centers) in proportion to where future capacity is likely to be built and they reflect the design attributes (roof pitches, etc.) that are representative of future systems.

PV resources at PGE include both behind-the-meter PV systems (distribution connected) as well as utility scale resources (transmission connected). As the VOS calculations will be done separately for these two types of resources, it is necessary to break these effectively into two fleets.

For the utility-scale resources, PGE may take the metered production over the Load Analysis Period, sum them hour for hour, and divide by the combined rating of the systems. This generation profile will reflect the irradiance values at the plant locations, and the specific design attributes for those plants.

The behind-the-meter resources are more complex. Generally, metered output for these resources is not available because production is netted with customer load on the customer side of the meter. Therefore, these resources are modeled using the time-synchronized solar resource data.

The PGE fleet comprises a large set of PV systems of varying orientations (different tilt angles and azimuth angles) at a large number of locations. The intention is to calculate costs and benefits for the PV fleet as a whole, rather than for a specific system with specific attributes. The principle is illustrated in Figure 2 where a range of tilt angles and azimuth angles would be expected to be found for the fleet. Each of these orientations contributes a different production profile as illustrated in Figure 3.

Figure 2. Illustration of capacity weighting by azimuth (x axis) and tilt angle (legend).

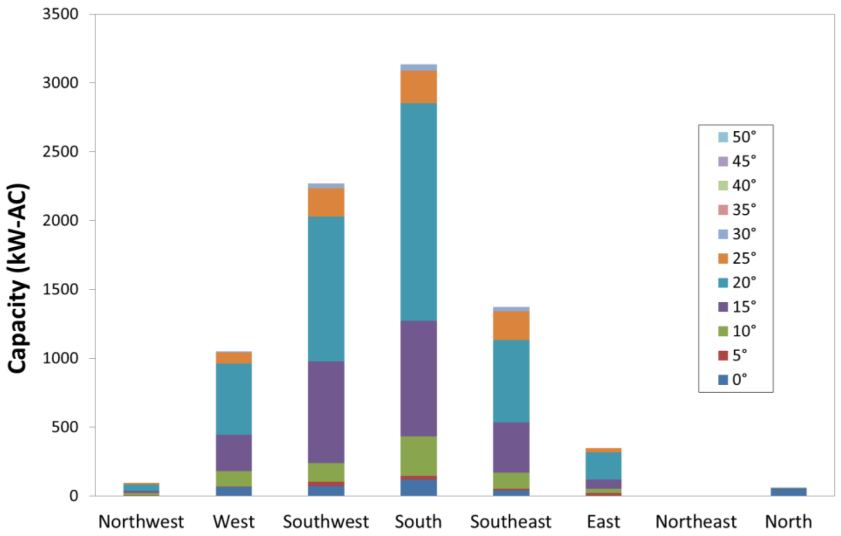
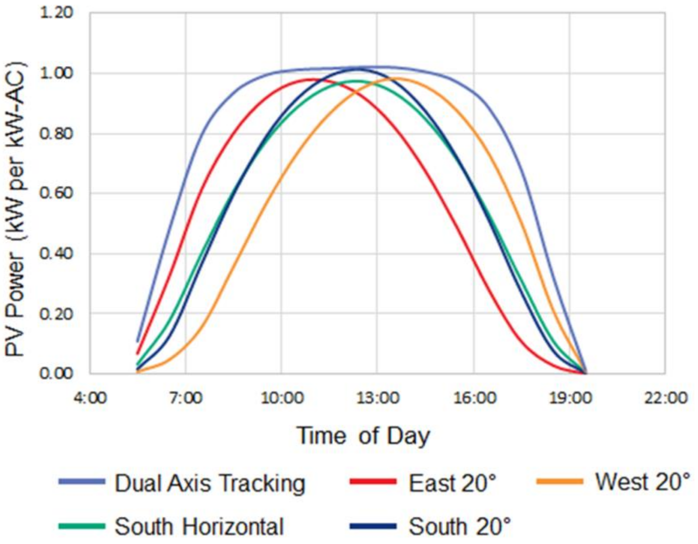


Figure 3. Illustration of PV generation profile by design orientation.



To develop the actual PV Fleet Production Profile it is necessary to take into account the actual fleet characteristics. This is done using the attributes collected in the PowerClerk® database for the Oregon Energy Trust (see Figure 4). Simulations may be performed using FleetView® software, incorporating satellite-derived irradiance data (SolarAnywhere®) or other simulation software, provided that the simulations are performed using actual design attributes for each system, and using irradiance and temperature data corresponding to each of the system locations.

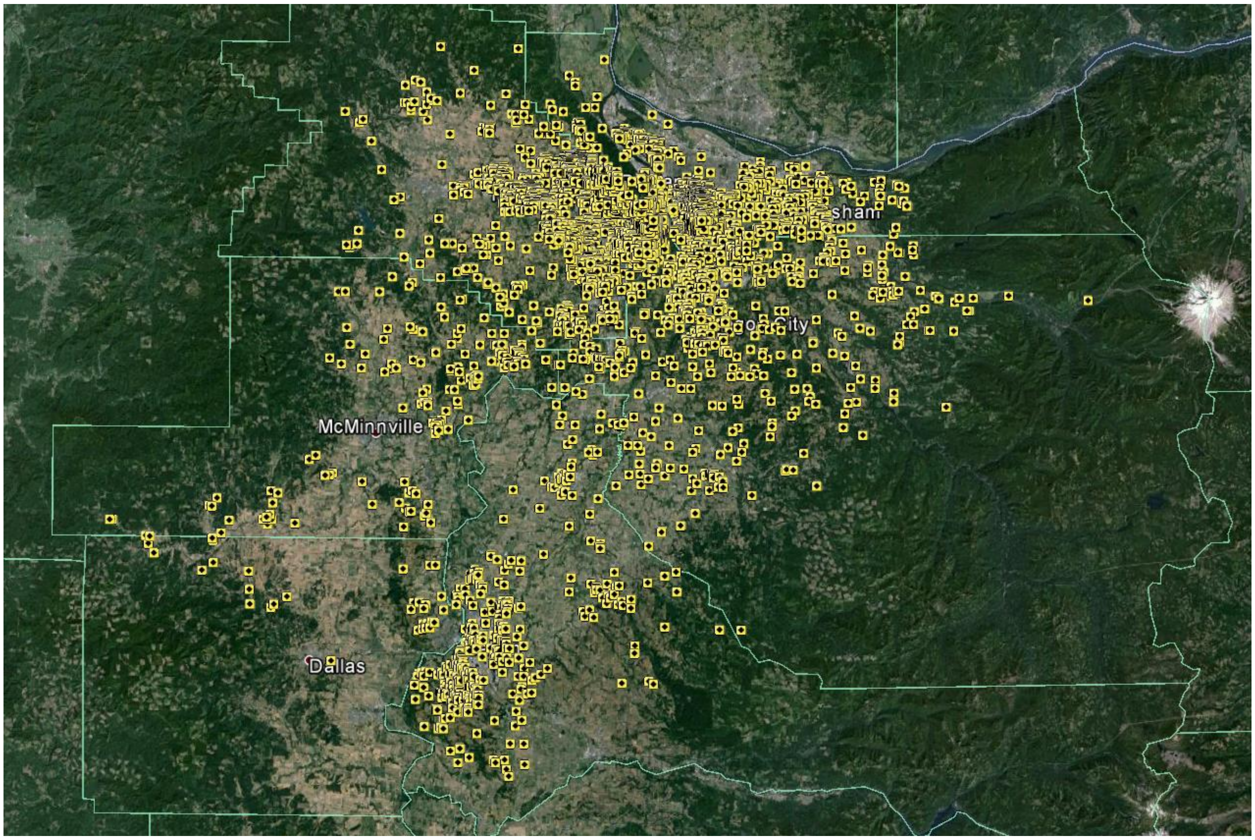


Figure 4. PGE behind-the-meter fleet locations (from FleetView).

For example, each system is mapped to its corresponding 10 km x 10 km weather data grid location from which temperature, wind speed, direct normal irradiance, and global horizontal irradiance would be taken. For each hour, the weather data is used, array-sun angles and plane-of-array irradiance is calculated, and PV system output is modeled with temperature and wind speed corrections.

PVFleetProduction

All systems are simulated individually over the Load Analysis Period, and the results aggregated. Finally, the energy for each hour is divided by the fleet aggregate AC rating. This results in the time series *PVFleetProduction* with units of kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Production Profile may be thought of as the hourly production of a Marginal PV Resource having a rating of 1 kW-AC. This “resource” does not exist in practice since there is no PV system having the output shape of the blended fleet. For ease of description, however, the term Marginal PV Resource is used and intended to mean the fleet blend as described above.

First Year Avoided Energy

The first year energy produced by PV (kWh per kW-AC per year), before annual PV degradation is taken into account, is the sum of the *PVFleetProduction* time series across all hours of the Load Analysis Period, divided by the number of years in the Load Analysis Period. The result is the first year annual output of the Marginal PV Resource.

$$AnnualEnergy_0 = \frac{\sum PVFleetProduction_h}{Number\ of\ Years} \tag{1}$$

AvoidedEnergy$_0$ does not include the effects of loss savings. The Loss Savings Analysis section describes the method for calculating factors to incorporate the effects of loss savings, and these factors are then used in the Final VOS Calculation section.

Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are calculated:

- Effective Capacity (EC)
- Peak Load Reduction (PLR)

Effective Capacity

Effective Capacity (EC) is the measure of the capacity for distributed PV that is applied to avoided generation capacity costs, avoided fixed O&M costs, avoided reserve capacity costs, and avoided transmission capacity costs. It is expressed as a percentage of rated capacity, and the percentage is an indication of effectiveness relative to a fully dispatchable resource.

PGE may utilize any of several methods for calculating EC, many of which are detailed in NREL's overview of methods for evaluating DG costs and benefits.[2] Three methods are considered here:

- Production during defined peak periods
- Production during peak load hours
- Loss of load probability (LOLP)

The first method is to calculate the average hourly PV production during defined peak periods. This method was included in the Minnesota Value of Solar methodology in order to be compatible with MISO rules for non-wind variable generation.[3] In the MISO case, for example, the period was defined as the hours ending 14:00, 15:00, and 16:00 CST during June, July, and August over the last three years. This method is simple to calculate once the production time series dataset is prepared, it is easy for

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[2] Denholm, et al., "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System," NREL, September 2014, available at: http://www.nrel.gov/docs/fy14osti/62447.pdf

[3] MISO BPM-011, Section 4.2.2.4, page 35, https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

stakeholders to understand, and it provides a straightforward methodology for implementation year after year in a tariff.

Alternatively, PGE could calculate EC based on distributed PV production during peak load hours. For example, the average production during the top 100 hours over the load analysis period could be used. This is also a simple calculation, and it provides a means for penetration level to be easily accounted for in future year updates. If penetration level increased, then peak hours may shift to non-solar hours, and this method would then result in an EC reflecting such a shift.

A third method would be to determine the rating of a dispatchable resource having the same loss of load probability (LOLP) as the Marginal PV Resource. This method provides a good measure of equivalent reliability, but it is more difficult to communicate to stakeholders and more difficult for stakeholders to validate independently.

While the PV capacity under evaluation is “new,” (i.e., installed in 2015), its impact on avoiding new generation capacity is not realized until at some year in the future (e.g., 2020), the year that new generation is scheduled for installation. Therefore, the EC of the new resource would be calculated for the year that new generation is scheduled for installation. For example, if the generation is scheduled for 2020, then the EC of the 2015 capacity would be evaluated based on the anticipated load shape in 2020.

Note that in order to ensure that PV production is correctly time-synchronized with load, both the PV production and the load data must be taken from the same hours. In this methodology, the time-synchronization is accomplished by using both PV fleet simulation results and load from the same hours in the Load Analysis Period. Utility loads are scaled according to projected retail sales (or projected peak load growth), taking into account anticipated PV capacity in the intervening years. It would not be correct to use “typical” year data for either the PV or load profiles unless the underlying raw data (temperature and irradiance) are taken from the same hours, i.e., the definition for typical year is the same for both load and PV.

For future years, the method for calculating utility hourly loads is as follows. First, utility loads from the Load Analysis Period are scaled by the projected annual energy sales (or projected peak load). All hourly loads are assumed to scale by this same ratio. Next, the hourly output of the differential PV resource for the future year (the difference between utility projected 2020 rooftop PV capacity and the PV capacity at the conclusion of the load analysis period) is calculated by multiplying the differential capacity by the hourly normalized fleet output.[4] Finally, the differential PV production is subtracted from the load to give the hourly net load.

This projection is illustrated in Figure 5 in which a 2020 generation capacity increase is assumed. The net load for 2020 is used to calculate EC.

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[4] Normalized output is the output in MWh per MW-AC of fleet capacity.

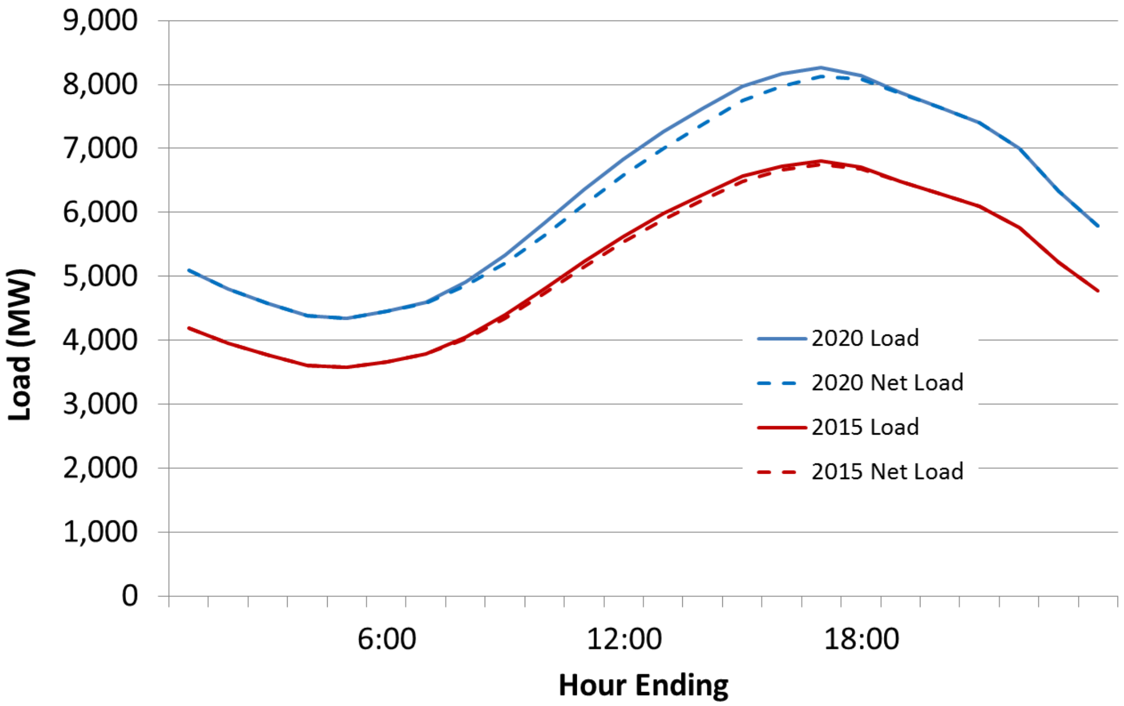

Figure 5. Peak day load and net load for 2015 and 2020 (illustrative).

As suggested by the chart, the EC may be a function of both the change in load and the change in PV installed capacity. Therefore, both of these effects need to be included in the calculation of future year EC.

The EC is calculated using PGE's selected method, then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Annual ECs are then averaged over the Load Analysis Period (if more than one year) to give the final fleet EC.

Additionally, the EC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Savings Analysis subsection). Note that the inclusion of transmission losses is only true when the avoided generation is off-system, and this is not always the case.

Peak Load Reduction

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it is necessary to calculate EC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* losses, and second by *excluding* losses. For example, the EC would first be calculated by including transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource. The loss savings factor associated with EC (described below) is then calculated using the two results.

The calculations should observe the following

Table 1. Losses to be considered.

Technical Parameter	Loss Savings Considered
Annual Avoided Energy	Avoided transmission and distribution losses for every hour of the Load Analysis Period.
EC	Avoided transmission and distribution losses during the critical hours.
PLR	Avoided distribution losses (not transmission) at the peak hour.

When calculating avoided marginal losses, the analysis will satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined as follows:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (2)$$

Equation (2) is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (3)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (4)$$

And the EC Loss Savings Factor is defined as:

$$Loss\ Savings_{EC} = \frac{EC_{WithLosses}}{EC_{WithoutLosses}} - 1 \tag{5}$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components.

Important note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Discount Factors

For this analysis, year 0 corresponds to the year of installation of the PV systems in question. As an example, if the calculation is performed for PV installations between January 1, 2016 and December 31, 2016, then year 0 would be 2016, year 1 would be 2017, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (6)$$

DiscountRate is the PGE after tax Weighted Average Cost of Capital. Either real or nominal discount rates, depending on whether the levelized value is to be calculated on a real basis or a nominal basis.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (7)$$

RiskFreeDiscountRate is based on the yields of current Treasury securities[5] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$AnnualEnergy_i = AnnualEnergy_0 \times (1 - PVDegradationRate)^i \qquad (8)$$

where PVDegradationRate is the annual rate of PV degradation.[6] $AnnualEnergy_0$ is the First Year Avoided Energy for the Marginal PV Resource.

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[5] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = PVCapacity_0 \times (1 - PVDegradationRate)^i \tag{9}$$

where *PVCapacity₀* is the initial capacity of the marginal resource, i.e., 1 kW-AC.

Each benefit and cost category is levelized by discounting future year amounts to get NPV and then using the following relationship:

$$LevelizedValue = \frac{NPV}{\sum PVProduction_i \times DiscountFactor_i} \tag{10}$$

Avoided Fuel Cost

The solar-weighted heat rate is calculated for each month *m* as follows:

$$SolarWeighedHeatRate_m = \frac{\sum HeatRate_j \times PVFleetProduction_j}{\sum PVFleetProduction_j} \tag{11}$$

where the summation is over all hours *j* of the Load Analysis Period for the month, *HeatRate* is the actual heat rate of the plant on the margin, and *PVFleetProduction* is the time series calculated as described in the PV Energy Production section.

A burnertip fuel price by month is a required input for the Avoided Fuel Cost calculation. This input may be from an internal utility forecast or from public sources,[7] adjusted for delivery.

The avoided unit fuel cost (in $ per kWh) for year *i* is calculated as:

$$AvoidedUnitFuelCost_i = \sum_{m=0}^{11} \frac{BurnertipFuelPrice_{m,i} \times SolarWeighedHeatRate_m}{10^6} \tag{12}$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh. For each year, the Avoided Fuel Cost in $ per year is calculated by multiplying the above annual result ($ per kWh) by the fleet production in kWh for that year, taking into account solar degradation. This value stream is then discounted and levelized as described in equation (10).

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[6] A good source of data for this assumption is the median value of systems from an NREL study of the literature. See Jordan and Kurtz, "Photovoltaic Degradation Rates – An Analytic Review," NREL, available at http://www.nrel.gov/docs/fy12osti/51664.pdf.

[7] For public sources, an option used in other studies is a combination of NYMEX NG futures (first 12 years) and then escalated using the EIA forecast of natural gas prices.

Avoided Variable O&M Cost

A required input to this calculation is the assumed first-year variable O&M cost in $ per kWh. This assumption should correspond to a typical resource that is displaced, such as a CCGT. For each year, escalate this value using an assumed escalation rate, multiply by the PV production in that year (after degradation), discount each year's value and levelize.

For example, if the variable O&M cost is $0.01 per kWh, nominal escalation is 2%, the first year Annual Energy is 1800 kWh per kW, and PV degradation is 0.05% per year, then the avoided O&M cost for study year 10 would be $0.01 x (1.02)^10 x 1800 x (0.95)^10 = $13 per kW-yr.

Avoided Generation Capacity Cost

Avoided Generation Capacity Cost is calculated initially for a "perfect" resource and is later adjusted based on the EC to account for the intermittent nature of the solar resource.

Generation capacity using conventional resources is assumed to take place at some year in the future. Therefore, new PV capacity (i.e., capacity added in 2015) will provide capacity immediately, but will not avoid capacity costs until the year in which new capacity was scheduled for construction. The methodology described here takes into account this time delay.

The key inputs for the Avoided Generation Capacity Cost component are the capital cost of new generating capacity (e.g., the installed cost of a CCGT) and the year in which the installation is expected to occur.

First, the capital cost is escalated to the assumed year of installation. In the example of Table 2 the escalated cost is shown as $1200 per kW occurring in 2020. This cost is amortized over the life of the plant (e.g., 30 years), and the example is an amortized cost of $106.59 beginning in study year 6. The potential avoided cost is represented, then, by the overlap of the annualized costs and the study period (PGE has defined this as 20 years). So, in this example, the amortized costs for years 6 through 19 are potentially deferrable. These costs are discounted to $598.08 per kW and levelized over the assumed 20 year life as $0.032 per kWh. In year 2030, for example, the levelized cost of $0.032 per kW may be multiplied by the PV production in that year of 1670 kWh per kW (after degradation) to obtain an avoided cost of $54.18 per kW. As a check in the calculation, the NPV for all years is shown to agree with the $598.08 per kW of avoided costs.

The capacity value should be adjusted to account for the fact that the displaced, dispatchable capacity could have been used during certain hours to dispatch economically in the market when not needed for load. Both energy and capacity could be sold during these hours.

Table 2. Avoided capacity value calculation (illustration only).

	Year	Disc. Fact.	Capital Cost ($/kW)	Amortized Cost ($/kW-yr)	Disc. ($/kW-yr)	Solar Production (kWh/kW)	Lev. Value ($/kWh)	Value ($/kW)	Disc. ($/kW)
0	2015	1.000				1,800	0.032	$ 58.41	$ 58.41
1	2016	0.926				1,791	0.032	$ 58.11	$ 53.81
2	2017	0.857				1,782	0.032	$ 57.82	$ 49.58
3	2018	0.794				1,773	0.032	$ 57.54	$ 45.67
4	2019	0.735				1,764	0.032	$ 57.25	$ 42.08
5	2020	0.681	1,200			1,755	0.032	$ 56.96	$ 38.77
6	2021	0.630		$106.59	$ 67.17	1,747	0.032	$ 56.68	$ 35.72
7	2022	0.583		$106.59	$ 62.20	1,738	0.032	$ 56.39	$ 32.90
8	2023	0.540		$106.59	$ 57.59	1,729	0.032	$ 56.11	$ 30.32
9	2024	0.500		$106.59	$ 53.32	1,721	0.032	$ 55.83	$ 27.93
10	2025	0.463		$106.59	$ 49.37	1,712	0.032	$ 55.55	$ 25.73
11	2026	0.429		$106.59	$ 45.72	1,703	0.032	$ 55.27	$ 23.71
12	2027	0.397		$106.59	$ 42.33	1,695	0.032	$ 55.00	$ 21.84
13	2028	0.368		$106.59	$ 39.19	1,686	0.032	$ 54.72	$ 20.12
14	2029	0.340		$106.59	$ 36.29	1,678	0.032	$ 54.45	$ 18.54
15	2030	0.315		$106.59	$ 33.60	1,670	0.032	$ 54.18	$ 17.08
16	2031	0.292		$106.59	$ 31.11	1,661	0.032	$ 53.91	$ 15.73
17	2032	0.270		$106.59	$ 28.81	1,653	0.032	$ 53.64	$ 14.50
18	2033	0.250		$106.59	$ 26.67	1,645	0.032	$ 53.37	$ 13.36
19	2034	0.232		$106.59	$ 24.70	1,636	0.032	$ 53.10	$ 12.30
	NPV				$ 598.08				$ 598.08

Avoided Reserve Capacity Cost

Distributed PV energy is delivered to the distribution system, not transmission. Therefore, load is reduced and the reserve requirement likewise decreases, similar to the effect of energy efficiency. Since this is just a fixed fraction of the generation capacity (e.g., 15%), it is treated as an add-on to the Avoided Generation Capacity Cost and included in that component.

Avoided Fixed O&M Cost

Again, the avoided costs are first calculated for a “perfect” resource and are later adjusted using the EC load match factor to account for the intermittent nature of PV.

The first year fixed O&M value ($ per kW) is an input to this calculation.

For each year, calculate the following:

- [1] the escalated cost of fixed O&M ($ per kW)
- [2] an index for the decreased capacity of the displaced generation resource taking into account the degradation of plant output over time. For simplicity, the heat rate degradation (from the fuel cost calculation) may be used.
- [3] an index for the decreased capacity of PV, taking into account the PV degradation rate.

- [4] the adjusted O&M cost ($ per kW) for that year, calculated as [1]x[3]/[4]

The NPV of this time series is calculated and levelized over the study period.

Solar Integration Cost

The Solar Integration Cost is the cost of the operational modifications needed to accept variable distributed PV onto the system. This variability is a function of PV penetration (MW of PV resource relative to the overall load), the geographical spread of resource, the time period of interest (i.e., the four second AGC period), and the speed of clouds causing the transients.

For example, two PV systems (System A and System B) located adjacent to each other would be highly time-correlated because a given cloud transient, measurable within the AGC period would be observable in the change in output for both System A and System B. However, if the two resources were separated by a large distance, the two would not be time correlated. In this case, a cloud transient may be observable at A (say, a sudden increase in PV power), but four seconds would not be sufficient time for the cloud to traverse the distance. At B, it is possible that (1) there is no cloud transient; (2) that there is a transient in the opposite direction (a sudden decrease in PV power); and (3) that there is a transient in the same direction.

With a large number of systems sufficiently spread out, the aggregate change in required regulation is a probabilistic function of the behavior of many systems. To measure the aggregate change, it would be necessary to meter distributed PV resources of the fleet, sample the integrated energy for each system over the four second period, and aggregate the time-synchronized results. The data would have to be collected over a representative duration, such as the Load Analysis Period (or at least a representative year). The cost and complexity of such as study by PGE would be considerable, however, and impractical for purposes of this methodology.

Two studies are available that may be of interest to PGE in estimating the integration costs. The first was conducted by Idaho Power,[8] which estimated costs of real-time market activities associated with deviations in solar production forecasts under hour-ahead scheduling. Load following resources were a mix of hydroelectric resources, gas-fired generators, and coal-fired generators. Costs ranged from $0.40 per MWh to $2.50 per MWh for PV capacity ranging from 100 MW to 700 MW. However, this study utilized data from only six locations using five minute intervals. The distributed fleet at PGE would comprise roughly 1500 times the number of locations[9] and 75 times the temporal resolution, both of which result in very little output correlation. On the other hand, many of these systems would be clustered in some areas with possible time correlation.

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[8] Solar Integration Study Report, 2014, by Idaho Power, available at https://www.idahopower.com/AboutUs/PlanningForFuture/SolarStudy/default.cfm.

[9] Roughly 9000 distributed systems in PGE's existing fleet divided by 6 systems in the Idaho sample is 1500.

A second relevant study was performed by Duke Energy Carolinas,[10] resulting in a range of $2 to $7 per MWh for baseline scenarios, for the penetration years 2014 to 2022. In this case, one-minute time-synchronized data was used for PV located in about 300 locations (at zip code centroids). It is also difficult to determine how these results may compare with PGE, except to recognize that capacity would be spread throughout each zip code rather than concentrated at a single location.

A study similar to the Duke Energy study could be performed at PGE using PV simulations using the exact locations of the distributed fleet over the Load Analysis Period. This would eliminate the geographical uncertainty, but it would be limited to the best available satellite-derived data time resolution of one-minute. There are other, advanced methods[11] that could be adapted to quantifying fleet variability at the four-second AGC time interval, but these have not been demonstrated yet for actual fleets.

For purposes of the methodology in the absence of PGE-specific results, PGE should either estimate a $ per MWh cost using best judgment from the available studies performed elsewhere, develop its own integration cost methodology, or assume that the cost is negligible.

Avoided Transmission Capacity Cost

Distributed PV has the potential to avoid or defer transmission investments, provided that they are made for the purpose of providing capacity, and provided that the solar production is coincident with the peak. This benefit assumes that the avoided resource is “off system,” although this may not always be the case.

Avoided Transmission Capacity Cost is calculated initially for a “perfect” resource and is later adjusted based on the EC to account for the intermittent nature of the solar resource.

The methodology for this value component is identical to that of Avoided Generation Capacity Cost, except that the cost of new transmission capacity is used ($ per kW) and the year that new generation capacity is expected. Table 2 is an example format for calculating this value.

Avoided Distribution Capacity Cost

As peak demand grows, distribution circuits and substations can approach capacity limits, requiring capital investments in distribution plant. Under these conditions, distributed PV may potentially defer or avoid the need to make these investments, provided that PV production is coincident with the local demand.

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[10] Lu, S., et. al., Duke Energy Photovoltaic Integration Study: Carolinas Service Areas, available at http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf. Clean Power Research provided the underlying solar data to PNNL for this work.

[11] For example, see http://www.cleanpower.com/wp-content/uploads/2012/02/071_ModelingPVFleetOutputVariability.pdf .

The intent of this methodology is to capture the benefit, if any, in deferring capacity-related capital expenditures, to the extent that distributed resources are able to defer them. Distribution expenditures that are intended to provide reliability are not deferrable.

This section describes the method for calculating avoided costs for a “perfect” resource. The match between solar and distribution peak is incorporated in the PLR load match factor described previously. Note that PGE performs planning studies and develops projects to provide reliable service under a range of system conditions. This includes winter days with heavy cloud cover, when solar availability may be at a minimum. In the extreme case, the PLR would be zero, that is, the distributed resource would not support the peak load at all. In this case the Avoided Distribution Capacity Cost would be zero and it would not be necessary to calculate the economic value.

Under certain scenarios, it is possible that distributed generation would require additional capacity-related investments, so this category would potentially be a cost rather than a benefit. For example, if the amount of DG were installed locally in sufficient quantity as to require new line or transformer capacity, and if the cost of this new capacity were greater than the savings realized elsewhere on the system, then there would be a net overall cost to PGE.

PGE’s summer peak load typically occurs at 4:00 to 6:00 PM, where the winter peak load occurs at 8:00 to 11:00 AM and again at 6:00 to 8:00 PM. Depending on the relative magnitudes of the peaks in specific distribution areas, the best match may be provided by west-facing systems. Using this methodology, it would be possible to quantify relative value for such configuration options if desired. Using the PV Fleet Production methods described above, however, the benefits and costs are calculated for the broad range of designs, some of which are not optimized for distribution benefits.

Avoided distribution capacity costs are determined using capital investment and peak growth rate data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts as illustrated in Table 3. Note that the capacity-related percentages are for illustration, and PGE may elect to modify these percentages.

The table illustrates the calculation of capacity-only investments for a sample year. Costs (e.g., new tie lines) that are for reliability should not be counted.

Table 3. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		$856,316,173

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, summing, and dividing by the kW increase in peak annual load over the 10 years.

Note that this method results in capital cost per unit of load growth, not per unit of capacity. It would be incorrect to use the added distribution capacity that results from this investment.

Future growth in peak load is based on the utility's estimated future growth over the next 15 years. It is calculated using the ratio of peak loads of the fifteenth year (year 15) and the peak load from the first year (year 1):

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1 \qquad (13)$$

If the resulting growth rate is zero or negative (before adding solar PV), set the avoided distribution capacity to zero.

Example Calculation

An example calculation of avoided distribution capital cost is presented in Table 4. This method is intended to derive an approximate value of the potential value that results from deferring capacity-related investments, assuming that there is a perfect load match between the distributed generation resource and the load, i.e., if the resource provided a constant reduction in load for every hour of the year. The actual load match, if any, is accounted for in the PLR load match factor.

This example includes two separate sections: the "Conventional Distribution Planning" section and the "Deferred Distribution Planning" section.

In the "Conventional Distribution Planning" section, the distribution cost for the first year is assumed to be $200 per kW of load growth. While the details in obtaining this cost are not shown, it is taken as an example value as if it were calculated using the method described above. This cost is escalated each year using an assumed PGE escalation rate for distribution capital costs.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. Note that for the first year or two, it may be possible to estimate actual capital costs based on existing expansion plans. However, since this data is not available over the economic study period, an estimate must be made based on the cost per unit of load growth.

In the example, the first year distribution capacity additions are shown as 50 MW. This is calculated based on the growth rate and the existing peak load. Multiplying 50 MW by the cost gives $10M for the first year, and this is discounted. Each future year is calculated in a similar fashion by taking into account the escalation rate of distribution capital costs, the expected load growth for that year, and the discount factor for that year.

The total discounted cost is determined by summing the discounted expenditures (shown as $149M in the example). This cost is then amortized over the study period.

The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Avoided costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the avoided cost for 2022 is ($14M - $13M)/54MW = $14 per effective kW of PV, and this is discounted to $8 per kW. Summing the discounted avoided costs for all years gives $166 per kW. The levelized VOS that gives the same NPV is shown to be $0.008 per kWh, taking into account the annual degradation of PV.

The method assumes implicitly that PV is assumed to be installed in sufficient capacity to allow the investment stream to be deferred for one year. In the example chart, distribution capacity supporting 50 MW of load growth would be deferred. Suppose that of these 50 MW, a 10 MW of load growth is expected in a particular area, but only 5 MW of cumulative DG is installed in that area. In this case, the distribution deferral would not be possible.

Table 4. (EXAMPLE) Economic value of avoided distribution capacity cost.

		Conventional Distribution Planning				**Deferred Distribution Planning**			
Year	**Distribution Cost**	**New Dist. Capacity**	**Capital Cost**	**Disc. Capital Cost**	**Amortized**	**Def. Dist. Capacity**	**Def. Capital Cost**	**Disc. Capital Cost**	**Amortized**
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

Table 4. (CONTINUED)

		Costs			Disc. Costs		Prices	
Year	**p.u. PV Production**	**Utility**	**VOS**	**Discount Factor**	**Utility**	**VOS**	**Utility**	**VOS**
	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	**$166**	**$166**

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows. When PV or other distributed generation resources are introduced onto the grid, this can affect line voltages depending upon generator rating, available solar resource, load, line conditions, and other factors. Furthermore, at the distribution level (in contrast to transmission) PV systems are more geographically concentrated. Depending upon concentration and weather variability, PV could cause fluctuations in voltage that would require additional regulation.

In some cases, these effects will require that utilities make modifications to the distribution system (e.g., adding voltage regulation or transformer capacity) to address the technical concerns. To quantify these costs, PGE may consider all systems installed over a representative period, e.g., the last three years, add the utility distribution costs associated with interconnecting these systems, and divide by the total rated capacity of these systems. Some systems (e.g., small systems in areas with high loads) may have no added cost, while some systems (e.g., large systems in areas with low loads or limited circuit capability) would have high costs. The aggregate cost per kW-AC would then be levelized over the analysis period.

Advanced Inverters

Advanced inverter technology is available to provide additional services which may be beneficial to the operation of the distribution system. These inverters can curtail production on demand, source or sink reactive power, and provide voltage and frequency ride through. These functions have already been proven in electric power systems in Europe and may be introduced in the U.S. in the near term once regulatory standards and markets evolve to incorporate them.

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and Voltage Regulation is kept as a placeholder for future value analyses.

Avoided Environmental Costs

With distributed PV, environmental emissions including carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrous oxides (NO_x) will be avoided, and these value components are defined to reflect these benefits. Other indirect environmental impacts (such as health care costs, etc.) are not included.

Estimates of avoided environmental costs are done in two steps: (1) determine the annual avoided emissions in tons of pollutant per MWh of PV production; and (2) applying forecasted market prices to the avoided emissions.

Calculating Avoided Emissions

Avoided emissions are calculated using the U.S. Environmental Protection Agency's "AVoided Emissions and geneRation Tool" (AVERT)[12] which calculates state-specific hourly avoided emissions of carbon dioxide (CO_2), nitrous oxides (NO_x), and sulfur dioxide (SO_2). The Northwest data file, or a PGE specific data file, would be used for the calculations.

Hourly avoided emissions are calculated using the PV Fleet Production Profile, and the average avoided emissions per year over the Load Analysis Period will be used as the annual avoided emissions per kWh.

Environmental Compliance

The State of Oregon has adopted a renewable portfolio standard (RPS)[13] which sets forth requirements for the delivery of electricity derived from renewable resources, expressed as a percentage of electricity sold to retail customers. As distributed PV is a qualifying renewable resource, the electricity produced may have value to PGE by reducing the quantity of renewable electricity to be procured. The value of the renewable attribute is captured in the value of renewable energy credits (RECs) associated with the distributed PV energy.

Another possible compliance benefit is related to possible greenhouse gas (GHG) compliance stemming from Section 111(d) of the Clean Air Act. If implemented, this will require Oregon to develop standards of performance for existing carbon sources and PGE would have to take measures to reduce carbon emissions. Distributed PV would partly reduce these compliance costs by reducing the amount of generation needed from carbon producing sources. The benefit per MWh may be calculated by PGE once the specifics of the compliance plan are developed.

If Section 111(d) is not implemented, then the valuation is simplified and the REC value may be taken as the compliance value. However, if Section 111(d) is implemented, then measures taken to meet the RPS requirement may also meet some, or all, of the GHG requirement. The cost of compliance will therefore be the cost to meet the RPS requirement, or the cost to meet the GHG requirement, whichever is greater.

The exact determination may need to change as regulatory rules are adopted.

Once these costs ($ per MWh) are known, then the calculation is performed for each year by multiplying the cost by PVProduction for that year. The result is a series of expenditures that may be discounted using each year's discount factor to obtain the NPV. Then, the NPV is levelized to give the levelized cost per kWh.

Avoided SO_2 Emissions

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[12] http://epa.gov/avert/

[13] Oregon Renewable Energy Act of 2007 (Senate Bill 838).

Avoided SO_2 Emissions will be calculated by applying the latest EPA allowance clearing price[14] to the AVERT analysis results, adjusting for inflation and PV degradation, and levelized using the standard discount rate.

Avoided Fuel Price Uncertainty

This value accounts for the avoidance of fuel price volatility associated with natural gas generation that is not present for solar generation. To put these two generation alternatives on the same footing, we calculate the cost that would be incurred to remove the price uncertainty for the amount of energy associated with solar generation.

The treatment of avoided uncertainty would be different depending upon metering arrangements. If solar generation is used to serve loads behind the meter, then this benefit accrues to the solar customer by avoiding energy purchased from the utility. If the energy is delivered to the grid directly for use by PGE in serving its customers, then the benefit accrues to all customers.

Note that price volatility is also mitigated by other sources (wind, nuclear, and hydro). Therefore, the methodology is designed to quantify the hedge associated only with the gas that is displaced by PV.

To eliminate the fuel price uncertainty in year *i*, one could enter into a futures contract for natural gas delivery in year *i*, and invest sufficient funds today in risk-free securities that mature in year *i*. The steps required are therefore as follows:

- Obtain the natural gas futures price for year *i*.
- Calculate the amount of avoided fuel based on an assumed heat rate and on the amount of anticipated plant degradation in year *i*, and calculate this future cost.
- Obtain the risk-free interest rate corresponding to maturation in year *i*.
- Discount the expense to obtain the present value using the risk-free discount rate.
- Subtract from this result the energy value, which is obtained by discounting the future expense at the utility discount rate. Note that this may not be equal to the energy value obtained through the use of electricity market values.
- The remaining value is the avoided risk.
- Levelize the avoided risk value using the risk-free discount rate.
- Repeat for all remaining years in the study period and sum.

There are two practical difficulties with this method, requiring some simplifying assumptions. First, it is difficult to obtain futures prices for contracts as long as the assumed PV life. The most readily available public data is the NYMEX market prices, but these are available only for 12 years. As a simplification, the methodology assumes NYMEX prices for the first 12 years, and then escalated values as described in the Avoided Fuel Cost section.

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[14] http://www.epa.gov/airmarkets/trading/2014/14summary.html

Second, while U.S. government securities provide a public source of effectively risk-free returns, these securities are only available for selected terms. For example, Treasury notes are available with maturities of 2, 3, 5, 7, and 10 years, but when it is necessary to have a yield corresponding to 6 years, there is no security available. To overcome this problem, linear interpolation is employed as required.

The above method may be adjusted to account for added market exposure related to solar variability. The addition of distributed solar will add uncertainty to forecasts of net load that are used to dispatch resources. In some cases, PGE will buy deficit power from the market, and in other cases PGE will sell excess power to the market. The effect of forecast bias error should be evaluated.

Final VOS Calculation

The values calculated above need to be adjusted for load match factors and loss savings factors. This is illustrated in Figure 1. The results are summed to give the distributed PV value.

Utility Scale Resources

For utility scale resources connected to transmission, the following modifications are required. First, these do not avoid transmission or distribution capital costs, so these components are removed. Second, these resources do not avoid losses in either the transmission or distribution system, so the loss savings factors are set to zero. These modifications are illustrated in Figure 6.

		Levelized Value	Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	🟥	Avoided Fuel Cost	C1				~~LSF-Energy~~		V1
	🟥	Avoided Variable O&M Cost	C2				~~LSF-Energy~~		V2
	🟥	Avoided Fixed O&M Cost	C3		EC		~~LSF-EC~~		V3
	🟥	Avoided Gen. Capacity Cost	C4		EC		~~LSF-EC~~		V4
	🟥	(Solar Integration Cost)	(C5)				~~LSF-Energy~~		(V5)
Transmission and Distribution	🟦	~~Avoided Trans. Capacity Cost~~	~~C6~~		~~EC~~		~~LSF-EC~~		~~V6~~
	🟦	~~Avoided Dist. Capacity Cost~~	~~C7~~		~~PLR~~		~~LSF-Dist~~		~~V7~~
	🟦	~~Voltage Regulation~~	~~C8~~						~~V8~~
Environmental	🟪	Avoided Environmental Compliance	C9				~~LSF-Energy~~		V9
	🟪	Avoided SO_2 Emissions	C10				~~LSF-Energy~~		V10
Customer	🟩	Avoided Fuel Price Uncertainty	C11				~~LSF-Energy~~		V11
									Total

Figure 6. Final VOS calculation for utility scale resources.

Societal Benefits

The sections above are intended to provide methods to estimate the benefits and costs from the utility perspective, that is, only the benefits and costs which accrue to the utility and its customers. There are additional benefits that may accrue to society, and these are described in this section.

Clean Power Research does not recommend to PGE whether any of the societal benefits should be included or excluded from a benefit and cost study. They represent public policy choices that must be evaluated by the affected parties.

Social Cost of Carbon

The Avoided Social Cost of Carbon (SCC) is a measure of the externality benefit based on the federal social cost of avoided CO_2 emissions. This cost is included here for completeness as it has been used as the basis of other value of solar studies.

The value for each year is calculated as follows. The SCC values for each year through 2050 are published by the EPA in 2007 dollars per metric ton.[15] For example, the SCC for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. These costs are adjusted for inflation, converted to dollars per short ton, and converted to cost per kWh using the AVERT analysis results, adjusting for PV degradation.

These values are then levelized using the environmental discount rate that corresponds to the selected SCC scenario. For example, if the SCC values were taken using the 3% discount rate scenario, then the environmental discount rate would be 3%. As this is a *real* discount rate, it may be converted into an equivalent nominal discount rate as follows:

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \tag{14}$$

The environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \tag{15}$$

Other Potential Values

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[15] The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document, found at: http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf

Other potential values of solar have been identified through a number of studies, summarized by a 2013 RMI meta-study.[16] These include:

- Market Price Response
- Economic Development
- Reliability and Resilience
- Land
- Water

In general, utility avoided costs are much easier to estimate than societal benefits because they are tied to market prices. For example, avoided fuel costs are relatively straightforward to calculate based on marginal heat rates and gas prices, although there is uncertainty associated with gas price forecast. Similarly, capacity costs are also relatively straightforward because costs are readily available based on equipment costs and installation experience.

On the other hand, pricing sources are not typically available for societal benefits, so estimates are more difficult. The potential societal benefit of land, for example, represents the societal value of leaving land undisturbed, land that may otherwise be required for building generation or T&D capacity. It would not be appropriate to use available land prices in such a valuation for two reasons. First, the land price is already embedded in the generation and T&D capacity benefits (land costs, land right-of-ways, and so on). Second, and more importantly, it is extremely difficult to estimate the societal benefit that comes from leaving land undeveloped. These benefits may include such things as the value of preserving open space for public enjoyment and the value of undisturbed habitat for the preservation of wildlife. These things are extremely difficult to quantify and are therefore highly speculative.

A similar difficulty may be found in quantifying the value of water. While the avoided cost of cooling water is embedded in the O&M cost, the societal benefit is more complicated. It is extremely difficult to determine the social benefit of leaving waterways undisturbed. In the case of hydroelectric power, other difficulties would arise related to the costs and benefits of recreational use, the impact on fisheries and agricultural interests, the effect on Native American communities, and so on.

Among these five potential values, the first three have associated methodologies that have been used in prior solar valuation studies. While speculative, these may be used or adapted if PGE were to decide to include them. The last two (land and water) do not have established methodologies.

Market Price Response

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[16] A Review of Solar PV Benefit and Cost Studies, Electricity Innovation Lab, Rocky Mountain Institute, 2013, available at http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies.pdf

This potential benefit refers to DG's effect on market prices related to a reduction in demand. Sometimes called "Demand Reduction Induced Price Effect (DRIPE)," price reductions may potentially be found in gas supply, electric energy, and electric capacity. While the price effects may be small, they would benefit all PGE customers for all energy sold, whether DG participants or not. The methodology is laid out in Chapter 7 of the *Avoided Energy Supply Costs in New England: 2013 Report.*[17]

Economic Development

Another component of value may derive from the increase in local solar jobs (e.g., engineering and installation), netted against losses of jobs for conventional power generation and delivery. Indirect benefits from these jobs may also result: increase in tax revenue that benefits state and local communities, and the multiplier effect (increase in local retail economic activity as a result of the net jobs increase), but these are more speculative.

A sample calculation of these benefits is found on p. 16-17 in a valuation study performed for Solar San Antonio.[18]

Reliability and Resilience

Another possible value relates to the ability of distributed solar to enhance the speed of recovery following major natural disasters, such as earthquakes, hurricanes, and tsunamis. These events generally result in widespread power outages. If DG is available to provide power to key customers, operating as individual islands, the recovery can be hastened and the total economic damage lessened. For example, DG at a grocery store or hardware store may be able to assist in recovery efforts, enabling the retailer to serve the community in the absence of utility power. Similarly, generation sources at hospitals, police stations, and fire stations may enable essential services.

It is important to note that such benefits cannot be provided unless the DG equipment is designed to operate without the utility present. For example, a solar generator may be equipped with an inverter that requires a utility voltage (current source mode) and not able to serve islanded loads independently. If so, then this benefit would not be provided by the generator.

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[17] Hornby, et al., *Avoided Energy Supply Costs in New England: 2013 Report*, Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, July 12, 2013, Synapse Energy Economics, available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf

[18] Jones, N, and Norris, B, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013, available at: http://www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf

A more complete description and methodology is provided in the “Disaster Recovery” section of the solar value report performed for Austin Energy in 2006.[19]

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[19] Hoff, et al., The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Clean Power Research, March 2006, available at: http://www.ilsr.org/wp-content/uploads/2013/03/Value-of-PV-to-Austin-Energy.pdf.

SOLAR GENERATION MARKET RESEARCH

Task 1: Solar Market Assessment and Cost Projections

B&V PROJECT NO. 186018
B&V FILE NO. 40.0000

PREPARED FOR

Portland General Electric

24 SEPTEMBER 2015

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1.0 Executive Summary

Portland General Electric (PGE) has a strong history of supporting many forms of distributed and renewable resources, including roof-top and utility-scale solar photovoltaic (PV) generation. While the utility already has some solar on its system, PGE's 2013 Integrated Resource Plan's (IRP) Action Plan included additional investigations for PGE to further explore solar in Oregon. In particular, the IRP called for a market assessment using technical, financial, and achievable screens of potential distributed solar generation within PGE's service area and utility-scale solar within the state of Oregon. Throughout this report, "potential" represents an upper-bound based on underlying assumptions. PGE retained Black & Veatch to complete these potential assessments and also to prepare cost forecasts for solar PV.

Multiple scenarios were tested, and the estimated potential in terms of installed capacity under technical, financial, and achievable screens are summarized in the table below. As is common in the solar industry, distributed solar systems are reported according to their direct current (dc) capacity rating, while utility-scale systems are reported based on their alternating current (ac) ratings.

Table 1-1 Summary of Solar Potential Assessment

POTENTIAL	TECHNICAL SCREEN	FINANCIAL SCREEN BY 2035	ACHIEVABLE SCREEN BY 2035
Distributed (MWdc)	2,810	1,410	125 to 223
Utility-Scale (MWac)	56,000	7,500 to 17,500	100 to 369
MWdc = megawatts direct current MWac = megawatts alternating current			

This report outlines Black & Veatch's cost estimates for solar PV systems, assessment of distributed solar potential, and assessment of utility-scale solar potential. Key findings are described in this executive summary.

1.1 SOLAR PV COST ESTIMATES

Black & Veatch developed cost estimates for representative distributed and utility-scale solar PV systems for 2015 and forecasted those costs on an annual basis through 2035. The main body of the report includes an overview of solar technologies, a discussion of Black & Veatch's cost estimating approach, cost estimates for distributed systems, and cost estimates for utility-scale systems.

Since 1998, rooftop PV system prices throughout the United States have fallen on average between 6 and 8 percent per year. The once seemingly aggressive goals of the US Department of Energy's (DOE's) SunShot Initiative now appear within reach because of (1) the rapid and prolonged decline in the prices of PV modules and other system components and (2) the potential to reduce labor and other "soft costs" as demonstrated by best practices in more mature PV markets.

Black & Veatch developed forecasts of installed PV costs for every year through 2035. One of the major assumptions of the forecast is that installed PV prices will meet the DOE's SunShot Initiative targets in 2025, resulting in a large decline from today's costs. Table 1-1 summarizes Black & Veatch's 2015 and 2035 cost estimates for distributed and utility-scale PV systems. Figure 1-1 shows the cost trend through 2035. By the end of the period, Black & Veatch forecasts costs to drop for all system types to between $0.9 and $1.3 per watt direct current (Wdc) (2014$). Residential system costs are projected to drop by approximately 65 percent, commercial system costs by approximately 55 percent, and utility-scale systems by approximately 45 percent. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with small continued improvements in costs offset by inflationary increases.

More details on the cost estimating approach, background, and a breakdown into major system components is provided in the main body of this report. A table of the annual projection of costs is provided in Appendix A.

Table 1-2 Summary of Distributed and Utility-Scale Solar PV Cost Estimates for 2015 and 2035 Installation (2014$)

SYSTEM CHARACTERISTICS		TOTAL INSTALLED COST ($/$W_{DC}$), 2014$	
APPLICATION	SIZE (kW$_{DC}$)	2015	2035
Distributed			
Residential rooftop	4	$3.74	$1.31
Commercial/industrial rooftop	50	$2.62	$1.18
Commercial/industrial rooftop	250	$2.50	$1.17
Utility-Scale			
Fixed-tilt, ground-mount	7,000	$1.96	$1.06
Fixed-tilt, ground-mount	28,000	$1.77	$0.96
Fixed-tilt, ground-mount	140,000	$1.71	$0.92
kWdc = kilowatt direct current			

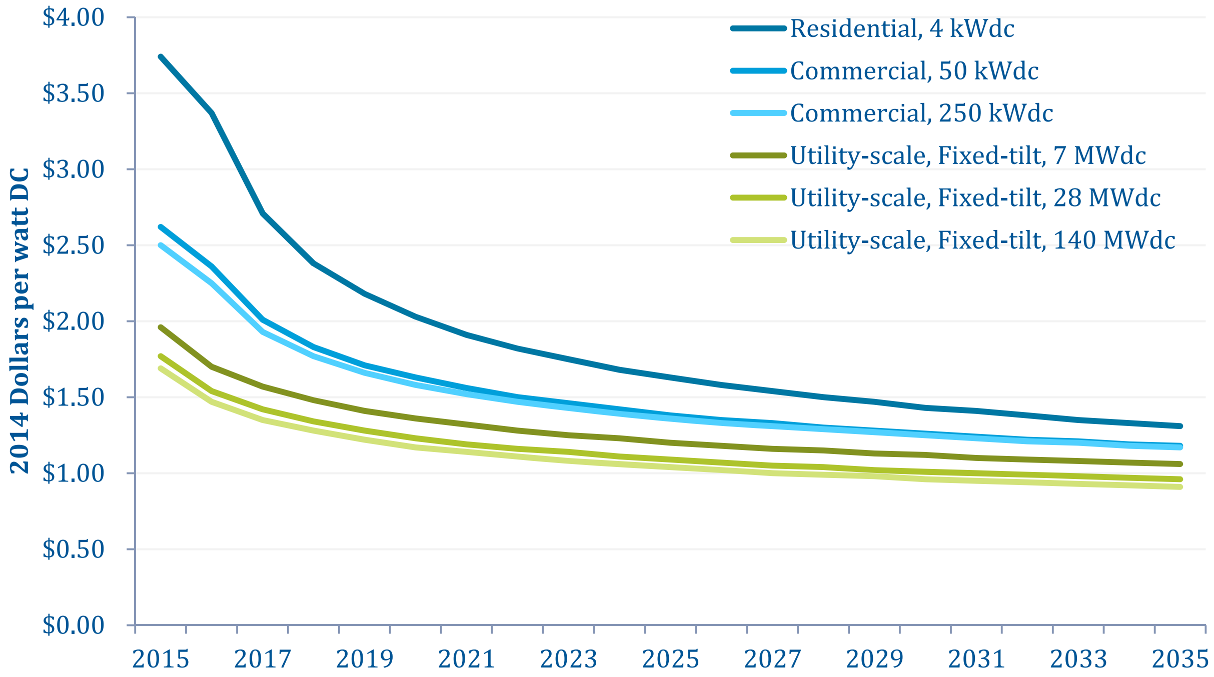
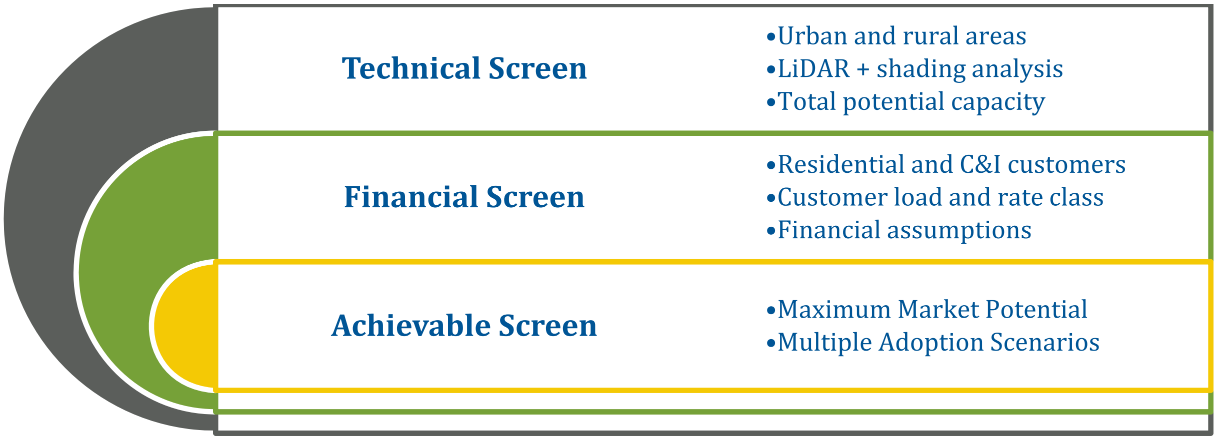


Figure 1-1 Solar Cost Projections (2014$/Wdc)

1.2 DISTRIBUTED SOLAR POTENTIAL ASSESSMENT

The distributed solar assessment focused on identifying the potential for solar installed on customer rooftops within PGE's service territory in northwest Oregon. Black & Veatch implemented an innovative approach to assess the technical potential using Light Detection and Ranging (LiDAR) data to evaluate the available area of individual buildings across PGE's service territory, studied the financials of each of these systems, and considered market penetration and other factors in determining the amount of distributed solar PV that could practically be achieved.

The approach used to quantify the technical, financial, and achievable potential for distributed systems is summarized as follows; additional details are provided in the main body of the report.



Technical Screen

- Urban and rural areas
- LiDAR + shading analysis
- Total potential capacity

Financial Screen

- Residential and C&I customers
- Customer load and rate class
- Financial assumptions

Achievable Screen

- Maximum Market Potential
- Multiple Adoption Scenarios

The technical screen used LiDAR data to provide detailed evaluation of 1.2 billion square feet of rooftop space representing over 400,000 buildings. A summary of the technical screen results by property type is provided in Table 1-3. The total technical potential of the areas assessed using LiDAR data was 1,800 MWdc. The technical screen estimate was scaled up for portions of the PGE territory where LiDAR data were not able to be used. After scaling up to cover the entire PGE service territory, the total technical potential amounted to 2,810 MWdc. About 30 percent of this amount is residential (single-family and multi-family), while the rest comprises commercial, industrial, and public/semi-public properties.

Table 1-3 Identified Distributed Solar PV Technical Potential

PARAMETER	LIDAR-ASSESSED AREA TOTAL CAPACITY (MWDC)	PGE SERVICE TERRITORY TOTAL CAPACITY (MWDC)
Single Family Residential	451	631
Multi-Family Residential	125	167
Commercial	586	874
Industrial	575	869
Public/Semi-Public	62	270
Total	**1,800**	**2,810**

For the financial screen, site-specific characteristics were developed to calculate the expected payback of individual buildings, accounting for solar generation profile, project size, and customer type. A detailed financial analysis was performed for hundreds of thousands of sites for four financial cases (Table 1-4). For the 2016 cases, this case included all incentives that are available to solar by customer type including federal investment tax credit (ITC of 30%) and accelerated depreciation, Oregon state tax credit for residential customers, and ETO funding. The 2016 case used the forecasted installed cost in 2016. The 2035 cases assumed no incentives would be available except for accelerated depreciation and included the 2035 forecasted installed cost. These two cost years were tested under utility rate increase conditions of Consumer Price Index (CPI) and CPI+1. Commercial and residential customers were calculated separately given different financial treatment and incentives in the years 2016 and 2035, under two rate increase scenarios (CPI and CPI+1 percent). .

Table 1-4 Financial Cases for Solar Distributed Generation

CASES	CPI	CPI+1
2016	All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI.	All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI+1 percent.
2035	No incentives are available, except accelerated depreciation. 2035 cost assumptions. Utility rate escalates at CPI	No incentives are available, except accelerated depreciation, 2035 cost assumptions. Utility rate escalates at CPI+1 percent

In addition to the financial analysis, multiple factors were considered in the screening. Projects were resized to match designated load profiles, so systems would not over-generate under the net metering tariff. Multi-family dwellings were excluded because there are challenges in installing systems for shared usage. Furthermore, since installing solar PV on rooftops is a long-term commitment that both residential and commercial renters are unlikely to pursue, ownership factors were applied as an additional screen to represent the portion of the property type that were owner-occupied. The resulting potential is estimated to be 1,410 MWdc. This figure comprises 415 MWdc of residential capacity and 995 MWdc of commercial capacity (commercial plus industrial and public/semi-public).

Incentives have long been an important part of the financials of PV, and Oregon has had some of the highest incentives for solar PV in the country. For example, the combined federal, state, and Energy Trust of Oregon (ETO) incentives can reduce the installed cost of PV in Oregon by approximately 55 to 75 percent. This reduction strongly influences the payback of systems in 2016. It was assumed that by 2035 no incentives (tax credits or state incentives) would be available, since the market should be mature and self-sustaining by that time. While Black & Veatch forecasts sharp declines in solar PV cost of 55 to 65 percent for distributed PV systems by 2035, these reductions are not enough to counteract the loss of incentives in many cases. Thus, the net cost after incentives to customers in real terms is actually lower in 2016 than it would be in 2035 for most cases. This effect had a major impact on the payback periods that were calculated for the financial screen.

Black & Veatch calculated customer payback for hundreds of thousands of customer systems over multiple scenarios. The distributions of payback periods are differentiated by residential and commercial customers for each of the financial cases tested.

Figure 1-2 is a sample comparing commercial payback distribution in 2016 and 2035 for the CPI+1 rate scenario. This chart represents the total MW of rooftop solar potential by increment of payback period (0.1 years). For both residential and commercial customers under both CPI and CPI + 1 scenarios, the distribution of payback periods are higher in 2035 than in 2016, as demonstrated in Figure 1-2. The results show that while the cost of solar is assumed to decline significantly by 2035, the modest rise in utility rates in both cases is not sufficient to offset the lack of incentives. Therefore, the payback periods increase significantly in 2035. Payback distribution charts for additional cases are available in the main body of the report.

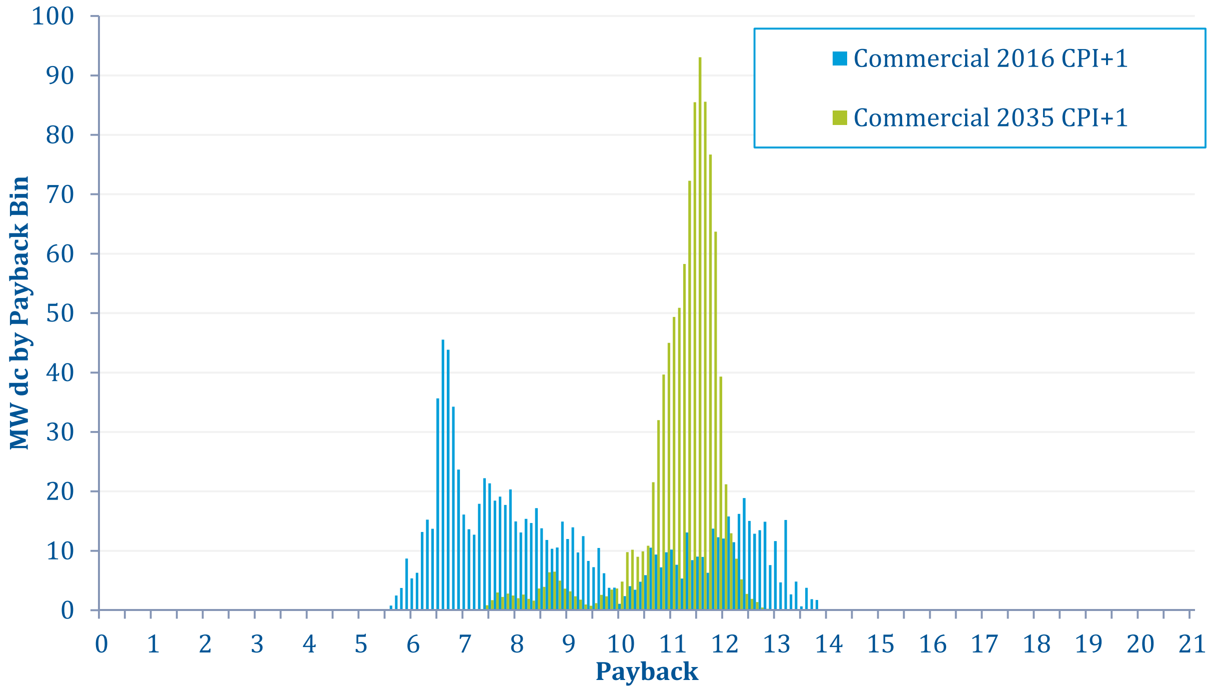


Figure 1-2 **Commercial Systems Payback Period (CPI+1)**

However, while the financial calculations show paybacks of less than 20 years for all systems, this does not necessarily translate to adoption by customers. There are numerous factors that influence a customer's decision to adopt a technology beyond financial viability.

In order to determine achievable potential within the study period, Black & Veatch used survey-based data to translate the payback distributions of customer systems to maximum market potential and then forecasted the adoption of solar over the study period. . Using the results of surveys of residential and commercial customers' preferences for adopting solar and distributed generation, NREL (residential) and Navigant (commercial) developed maximum market penetration curves that indicate the likelihood of market penetration given a certain amount of payback for that customer class. The survey data specifies what portion of a group of customers, given a certain payback outlook, would actually adopt the technology--the shorter the payback period, the more likelihood of adoption. The portion that would adopt makes up the maximum market potential. The maximum market potential was calculated for each customer class using the payback distributions for the 2016 and 2035 cases under the two rate increase assumptions (CPI and CPI+1). Therefore, four different maximum market potentials were calculated.

The resulting cumulative maximum market potential for each of the cases tested is shown in Table 1-5. These totals include already installed systems in PGE territory. Current and estimated 2015 commercial and residential rooftop installations total 47.9 MW.

Table 1-5 Summary of Maximum Market Potential for DG Solar (MWdc)

	CPI		CPI+1	
	2016	**2035**	**2016**	**2035**
Residential	180	102	192	145
Commercial	70	14	81	37
Total	**250**	**116**	**273**	**182**
Remaining Potential (Less Current and 2015 Installations)	**202**	**68**	**225**	**134**

Taking the remaining potential, Black & Veatch then developed estimates of annual adoption based on a range of market adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch took two approaches to capture the range of potential adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO funding constrained).

1. **Technology Adoption Limited:** The first approach is a bottom-up approach using the previously discussed payback analysis and survey data to determine maximum achievable market potential and applying a technology adoption curve to simulate annual adoption going forward. In these scenarios, since the payback distribution is higher in 2035 than in 2016, the maximum achievable market actually declines.

2. **ETO Funding Constrained:** For the top-down approach, Black & Veatch opted to test alternative scenarios where the payback, thus the maximum market potential,over time, is maintained at the same level as in 2016. This is done through adjusting ETO incentive levels ($/W) on an annual basis under various tax incentive and rate increase conditions.

For the technology adoption limited approach, cumulative adoption flattens out around 2028 as the customers who would adopt have already adopted solar, and the financials of solar limit further growth of the market. The maximum adoption of solar over the study period is 164 MWdc in the CPI+1 scenario.

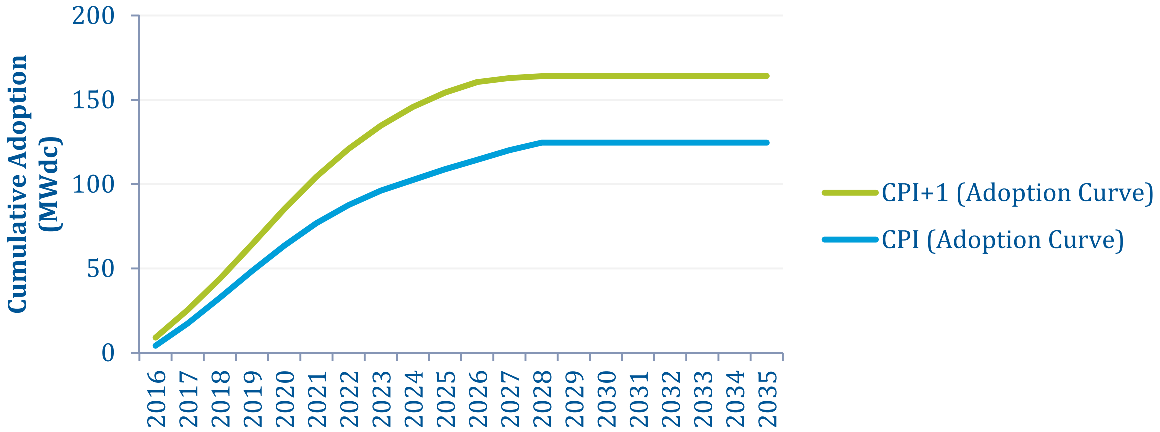


Figure 1-3 Technology Adoption Limited Cumulative DG Adoption

The technology adoption limited approach is a bottom-up analysis based on market adoption concepts. Another approach, which is a top-down approach, is to assume that ETO funding influences market adoption. The ETO, funded through system benefits charges (SBC), currently provides incentives to most projects installed in Oregon. ETO's budget is set on an annual basis and greatly impacts the net cost to customers and, thus, the adoption of solar in Oregon. Several funding scenarios were evaluated with and without additional federal and state tax credits. The assumed objective for these scenarios is that the ETO would provide enough incentives ($/W) to maintain similar payback levels as those modeled for the 2016 case for residential and commercial customers. The one limitation is that the absolute annual ETO funding is capped, which limits the MW of projects that the annual budget can support. The resulting cumulative adoption over time is shown on Figure 1-4, with maximum adoption of 224 MWdc in the CPI+1 (tax credits) scenario. Note adoption is slower and less when there are no tax credits available because higher ETO incentives ($/W) are needed to offset upfront costs, which means less MW can be funded, given a fixed annual ETO funding cap tied to SBC.

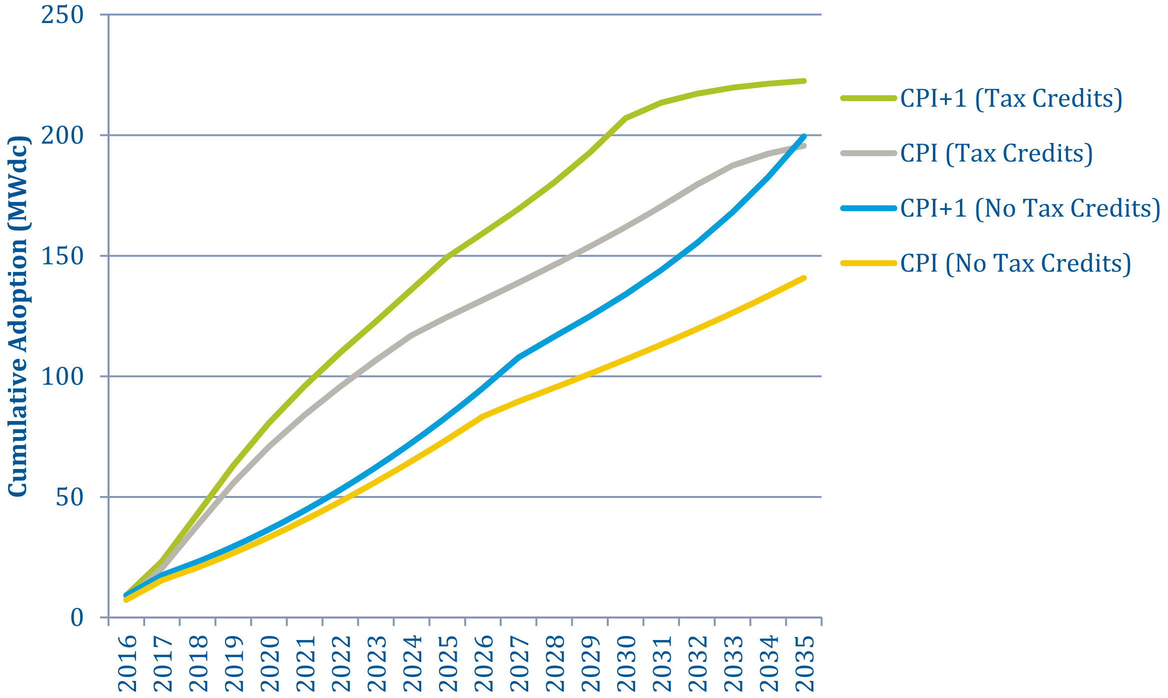


Figure 1-4 ETO Funding Constrained Solar DG Cumulative Adoption (2016-2035)

1.3 UTILITY-SCALE SOLAR POTENTIAL ASSESSMENT

The utility-scale solar potential assessment focused on areas across Oregon for projects ranging from 5 to 250 MWac. Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites, assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect. This assumes no new transmission is built in Oregon.

The technical screen found a total of over 56 GWac of solar potential in Oregon after limiting the maximum size of systems that can interconnect to transmission lines for each transmission voltage level.

For the financial screening, Black & Veatch calculated the levelized cost of energy (LCOE) for each project site for the years 2016 to 2035 with and without the federal investment tax credit (ITC) of 10 percent. Project costs include total installed cost for the respective year being analyzed, generation tie to the transmission system, substation costs to upgrade an existing substation or build a project-specific substation, ongoing operation and maintenance (O&M) including property taxes, and transmission tariffs/wheeling costs and losses to deliver energy to PGE's service territory. Supply curves based on LCOE were created for each year. Figure 1-5 and Figure 1-6 show sample supply curves for the years 2016, 2017, 2025, and 2035. It is important to note that the financial screen does not consider available firm transmission capacity for delivery to PGE's service territory.

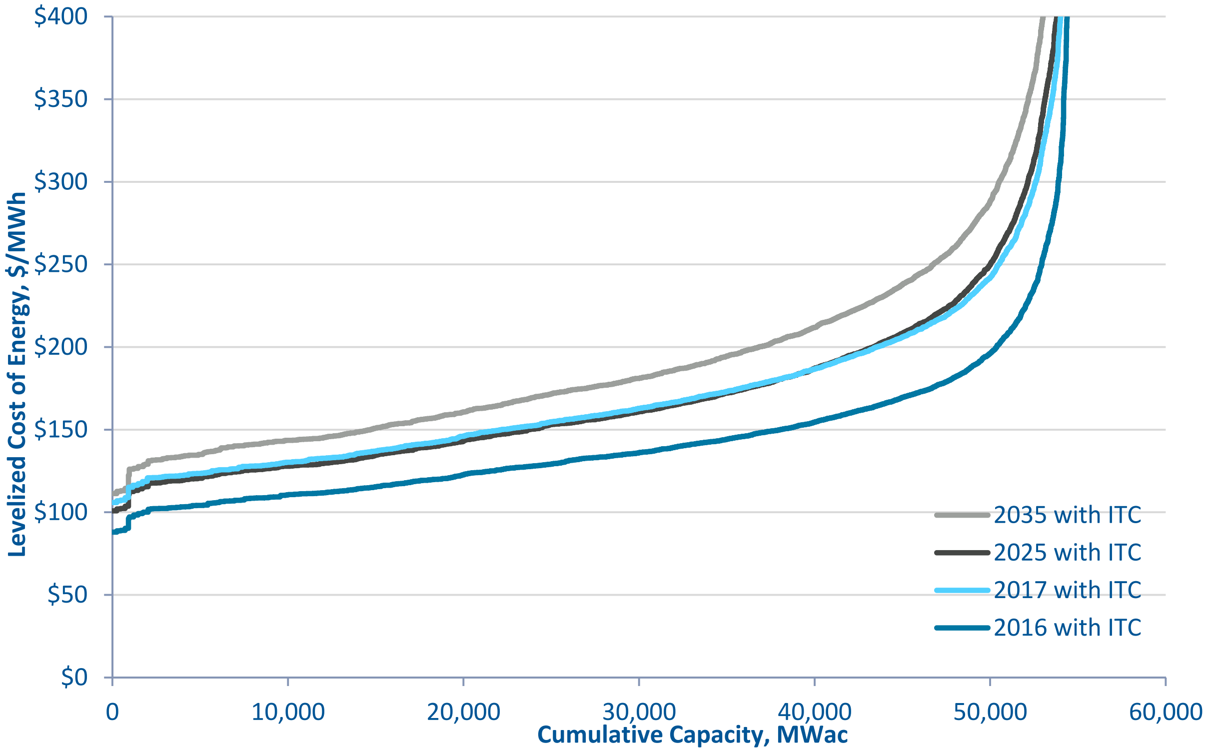


Figure 1-5 Utility Solar Supply Curve With ITC (10% after 2016)

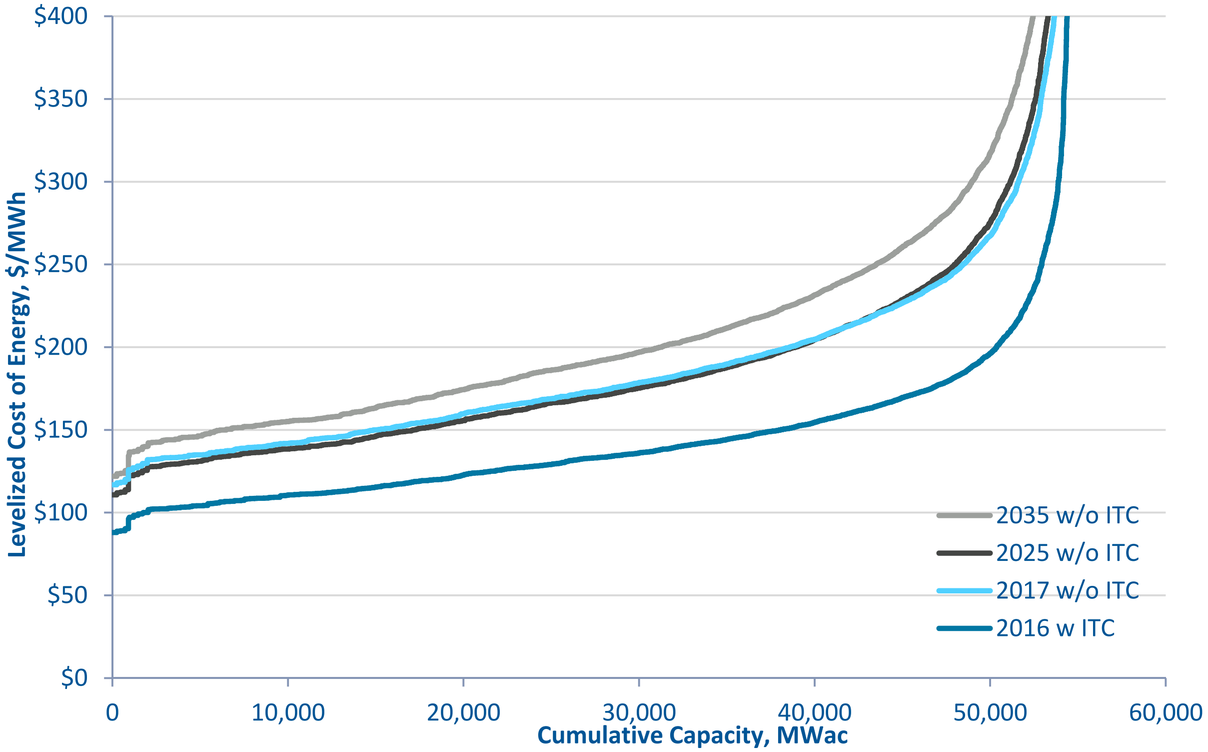


Figure 1-6 Utility Solar Supply Curve Without ITC

The LCOE supply curves were compared to the long-term levelized price for variable solar under PGE's long-term QF rates. The amount of capacity with LCOE lower than levelized QF rates increases over time as solar PV costs are forecasted to decline, along with increasing levelized cost of QF prices. The resulting potential by year with this financial screen is shown on Figure 1-7. By 2035, 7.5 gigawatts (GW) (no ITC) and 15.5 GW (ITC) of potential are considered financially viable. There is significantly less potential if no ITC is available.

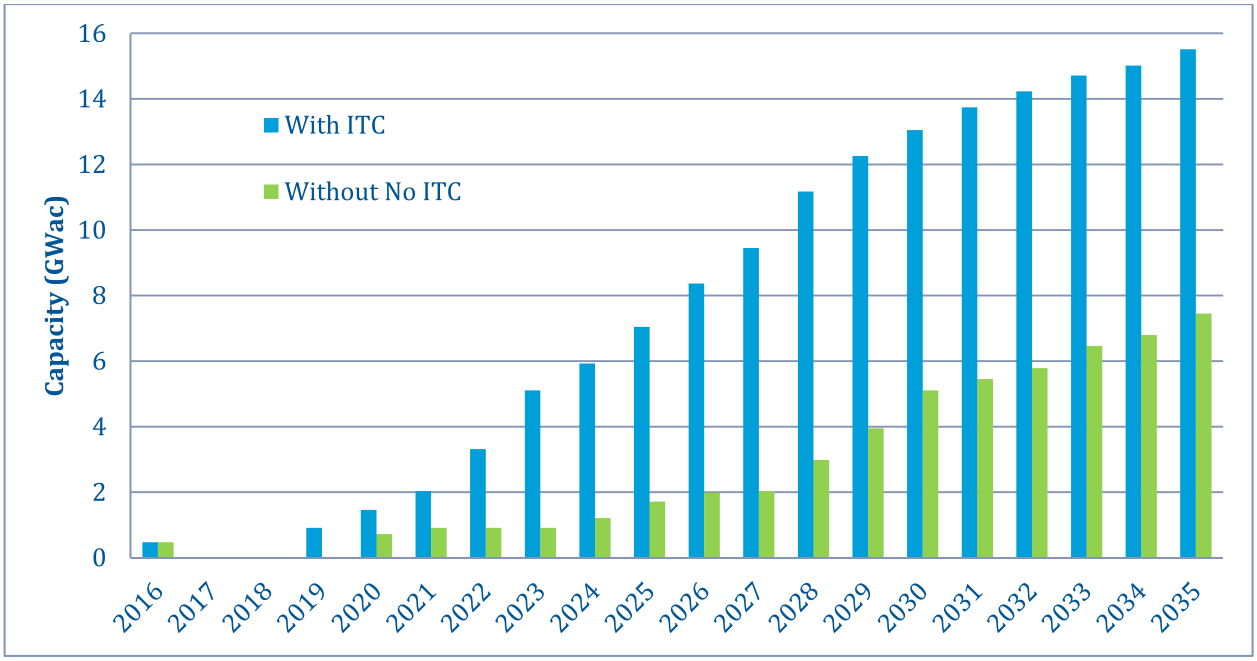


Figure 1-7 **Annual Maximum Potential with Financial Screen (No Transmission Constraints) for Utility-Scale Solar PV**

The financial screen did not consider transmission constraints to deliver the power to PGE's service territory. To estimate achievable potential for utility-scale solar, Black & Veatch assumed that the primary constraint is transmission availability. While transmission could be upgraded to deliver solar PV, such upgrades would be relatively expensive given the low utilization rate of solar. With input from PGE, several transmission zones were established for areas where PGE's staff estimated firm transmission capacity that may be available for delivery to PGE's service territory. Projects were also resized in order to meet these constraints, which impacted the cost of the PV systems. Sites were then identified that were less than the levelized QF price for each year. The cumulative solar penetration, with and without ITC, is shown on Figure 1-8. When the ITC is not available, no projects are financially viable until 2035, the last year in the study period, when 100 MWac of PV becomes financially viable. For the With ITC case, 369 MWac of total capacity are installed by the end of the study period.

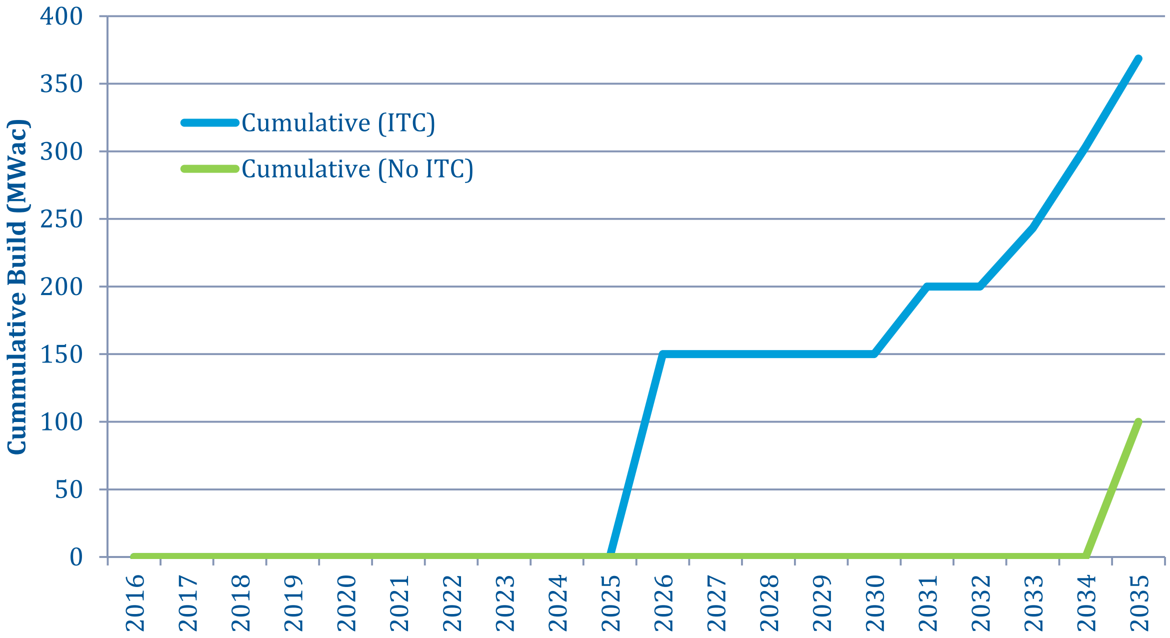


Figure 1-8 **Cumulative Utility-Scale Solar Achievable Potential**

1.4 SUMMARY CONCLUSIONS

The technical potential for distributed solar is significant in PGE's service territory, but continued incentives or alternative financing, such as leasing, will be needed to sustain higher levels of adoption. The study findings indicate that, given forecasted capital costs, the market potential by 2035 will continue to require incentives or alternative financing, at some level to support growth of the market. Otherwise, without additional incentives or alternative financing, the maximum market potential is constrained, meaning there is a limited pool of customers who would choose to adopt solar PV despite solar being financially viable.

Thus, additional incentives that can drive the net cost to customers down further or alternative financing mechanisms, such as third-party leasing, may help expand the market potential and should be studied further. Black & Veatch acknowledges that third-party leasing of systems, where customers do not have to pay an upfront cost, are becoming more prevalent in PGE's service territory. However, given the observed pricing behavior of third-party participants, such as Solar City, resulting in negative earnings, it was not possible to model third party ownership (TPO) financials in a reasonable manner. Furthermore, it was not possible to rely on historical data, as the historical annual dc capacity installed for both residential and commercial customers have not really increased in the past few years, despite increasing TPO participation. This is primarily due to external market constraints including ETO funding and the Solar Payment Option (SPO) programs.

Lastly, based on recent surveys conducted by NREL on market penetration using alternative financial metrics, such as bill reduction, the survey results indicate less than 20 percent market penetration for bill savings of less than 20 percent (Figure 1-9) for residential customers.[1] There was not a similar survey conducted for commercial customers. Due to the sensitivity of the overall study results to the Maximum Market Penetration Curves developed by NREL and Navigant (and R.W. Beck), Black & Veatch recommends PGE perform a similar survey for its customer base (residential and commercial) for both payback and percent bill savings.

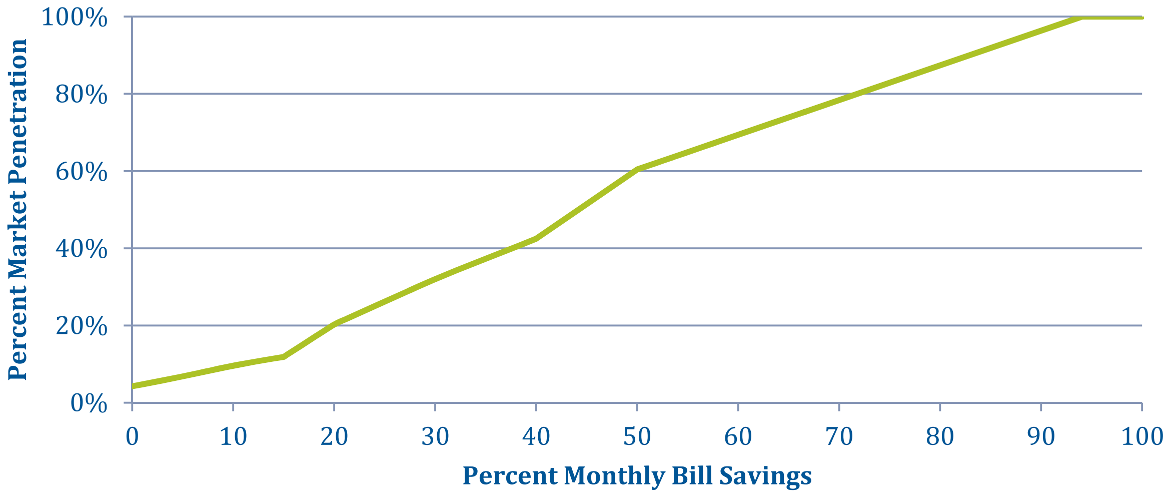


Figure 1-9 **2014 NREL Solar PV Market Penetration Curve Based on Monthly Bill Savings Survey of Residential Customers (Source: NREL)**

Additionally, it is important to note that the technical potential estimate is based on assessment of the current building stock within PGE's territory. New construction could cause the technical, financial, and achievable potential to increase over time. A number of other factors could also influence capacity over time, including the following:

- Modifications to the existing building stock.
- Growth/removal of trees and other shading sources.
- Improvements in solar panel efficiency, which would improve panel density per area.
- Changes in permitting/zoning requirements and restrictions.
- Innovations in mounting structures, such as lower cost solar carports.

Black & Veatch recommends that PGE regularly update the technical potential estimate and consider these factors in future studies.

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[1] NREL provided maximum market penetration curves for residential sector only to Black & Veatch. Surveys were performed in 2014 and assessed market penetration based on payback, monthly bill savings, internal rate of return, and net present value. Data is not yet published.

For utility-scale solar, the long-term QF pricing for variable solar appears not to be sufficient to drive long-term large-scale solar adoption in Oregon when the ITC is not available. If the ITC is available at 10 percent, cost-effective solar becomes possible by 2026. Additional penetration may be possible if developers are willing to build projects for less than the assumed return requirements of 6.5 percent, capital costs are lower than forecasted, or more value is placed on large-scale solar than just QF pricing.

The tables below summarize the achievable potential identified by Black & Veatch for both distributed-scale and utility-scale systems.

Table 1-6 Annual Solar Distributed Generation Adoption (MWdc)

	CPI (ADOPTION CURVE)	CPI+1 (ADOPTION CURVE)	CPI (ETO FUNDING - NO TAX CREDITS)	CPI+1 (ETO FUNDING - NO TAX CREDITS)	CPI (ETO FUNDING – WITH TAX CREDITS)	CPI+1 (ETO FUNDING – WITH TAX CREDITS)
2016	4.2	9.0	7.3	9.2	7.3	9.2
2017	13.2	16.4	8.1	8.3	13.1	14.1
2018	15.2	18.6	5.3	5.5	17.9	19.8
2019	15.9	20.2	6.0	6.3	17.4	20.0
2020	14.9	20.9	6.6	7.1	15.1	17.5
2021	13.4	19.3	7.1	7.8	13.1	15.3
2022	10.7	16.5	7.6	8.6	11.8	13.9
2023	8.5	13.8	8.1	9.3	10.9	13.0
2024	6.4	11.1	8.6	10.1	10.3	13.3
2025	6.3	8.5	9.1	10.9	7.6	13.4
2026	5.6	6.3	9.5	11.8	7.1	9.9
2027	5.7	2.3	6.2	12.7	7.1	10.1
2028	4.5	1.1	5.7	8.6	7.3	11.0
2029	0.0	0.2	5.8	8.4	7.7	12.4
2030	0.0	0.0	5.9	9.1	8.1	14.2
2031	0.0	0.0	6.2	10.1	8.5	6.4
2032	0.0	0.0	6.4	11.3	9.1	3.7
2033	0.0	0.0	6.7	12.7	7.9	2.5
2034	0.0	0.0	7.1	14.6	4.9	1.7
2035	0.0	0.0	7.4	16.9	3.3	1.1
Total	**124.6**	**164.2**	**140.8**	**199.5**	**195.6**	**222.5**

Table 1-7 Annual Build-Out of Utility-Scale Solar PV

YEAR	ANNUAL BUILD (ITC) MWAC	ANNUAL BUILD (NO ITC) MWAC
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026	150	
2027		
2028		
2029		
2030		
2031	50	
2032		
2033	43	
2034	60	
2035	65	100
Total	**369**	**100**

2.0 Introduction

Portland General Electric (PGE) retained Black & Veatch to provide an assessment of the potential for distributed solar photovoltaic (PV) generation within PGE's service area in northwest Oregon and utility-scale solar PV throughout Oregon. This report outlines the solar potential in each size range and also presents forecasts of solar costs.

This introductory section provides a background to the project and an overview of the report organization.

2.1 BACKGROUND

Portland General Electric (PGE) has a strong history of supporting many forms of distributed and renewable resources, including roof-top and utility-scale solar photovoltaic (PV) generation. PGE has approximately 55 megawatts direct current (MWdc) of distributed generation solar on the PGE system consisting of multiple programs. PGE has had a net-metering program since 1999 and participates in the state of Oregon's Solar Volumetric Incentive and Payments Program (effectively a feed-in tariff, or "FIT" program), for which it has a 16 MWdc cap. PGE has also developed several solar PV projects, including two solar highway projects: a 104 kilowatt direct current (kWdc) system that was the first solar highway project in the nation and a 1.75 MWdc project (Baldock Solar Highway). In partnership with customers, PGE is developing 3.5 MWdc of rooftop solar. In addition to DG solar resources, PGE purchases utility-scale solar PV generation totaling 14 MWdc.

PGE's 2013 Integrated Resource Plan (IRP) recommended studies and research initiatives to assess the market potential, business models, and policies that support installation of cost-effective distributed generation, in particular solar. "Potential" represents an upper-bound based on underlying assumptions. As part of the initiative, PGE identified the following areas of study:

1. Assessment of technical, financial, and achievable potential of distributed solar within PGE's service area and utility-scale solar within the state of Oregon.
2. Assistance in developing a methodology and models to calculate the costs and benefits of distributed and utility-scale solar ("value of solar") to the utility and customers that mitigates cost shifts between customers.

Black & Veatch was retained by PGE to support Task 1. Task 2 is reported in a separate document. As part of Task 1, Black & Veatch also provided current and forecasted costs for distributed and utility-scale solar projects. This report summarizes the findings of these analyses.

2.2 REPORT ORGANIZATION

Following this introduction, the report presents three main sections as follows:

- **Solar PV Cost Projections:** Black & Veatch developed total installed cost estimates for representative distributed and utility-scale solar PV systems for 2015 installation and forecasted those costs yearly through 2035. This section includes a basic overview of solar technologies, a discussion of Black & Veatch's cost estimating approach, cost estimates for distributed systems, and cost estimates for utility-scale systems.
- **Distributed Solar Potential Assessment:** The distributed solar assessment focused on identifying the potential for solar installed on customer rooftops within PGE's service territory. Black & Veatch implemented an innovative approach to assess the technical rooftop solar potential using Light Detection and Ranging (LiDAR) data to evaluate each individual building site across PGE's service territory, studied the financial viability of each of these systems, and considered market penetration and other factors in determining the dc capacity of distributed solar PV that could practically be achieved through 2035.
- **Utility-Scale Solar Potential Assessment:** The utility-scale solar analysis assessed potential project areas in Oregon ranging from 5 to 250 MWac. For the utility-scale system analysis, Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect.

In addition to these three main report sections, several appendices include additional technical and modelling data for reference.

The achievable potential estimates for DG and utility-scale solar were developed for the time period of 2016 to 2035, based on the forecasted cost estimates and other adoption factors. This report summarizes the Black & Veatch analysis and results for both distributed and utility-scale solar PV resources. A separate report discusses non-solar distributed generation resources.[2]

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[2] "Non-Solar Distributed Generation Market Research," Black & Veatch, 2016.

3.0 Solar PV Cost Projections

Black & Veatch developed total installed cost projections for distributed and utility-scale solar PV systems. Estimates were made for systems installed in 2015 and forecasted for each year through 2035. To provide context for these estimates, this section begins with a basic overview of solar technologies. This is followed by a discussion of the cost estimating approach used, the estimates for distributed systems, and the estimates for utility-scale systems.

3.1 SOLAR TECHNOLOGY OVERVIEW

Solar PV systems consist primarily of solar modules, inverters, and racking systems. Sample components for distributed (typically roof-mounted) PV systems and utility-scale (typically ground-mounted) PV systems are shown in Figure 3-1 and Figure 3-2.

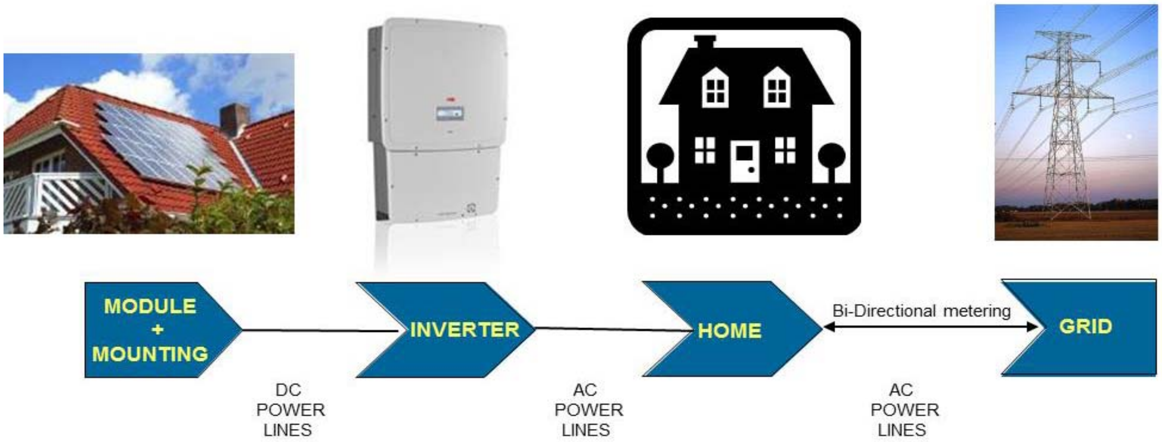

Figure 3-1 Example Components for Distributed Solar PV System

Figure 3-2 Example Components for Utility-Scale Solar PV System

There are three main types of module technologies[3]: monocrystalline, polycrystalline, and thin film, in order of their efficiency from highest to lowest. Less efficient technologies do not necessarily mean inferior performance; aside from some slight variations in performance curves, the main difference is that less efficient technologies require more surface area for the same amount of output. The selection of a particular module technology depends on the cost of the technology and presence of site space constraints.

Inverters convert the direct current (dc) output of solar modules to alternating current (ac), so that the power can be utilized by the electrical grid and most electrical devices. Solar system nameplate capacity may be reported in dc or ac, representing the capacity of modules and capacity of inverters, respectively.

Racking systems refer to the support system for solar modules. There are two main types of racking systems: fixed tilt and single-axis tracking. The latter tracks the sun's movement from east to west. There are dual-axis tracking systems[4] that track the sun's shift north to south as well, but these systems are more costly and less common in the industry. Due to the ability to track the sun, the single-axis tracking systems can produce more energy on average than fixed-tilt systems, but the tracking systems cost more. Therefore, regardless of the module technologies or racking systems selected, the levelized cost of energy (LCOE) for these various combinations are typically similar.

It should be noted that racking systems can be built over parking lots as well. These are often referred to as carport systems. The expense to build the elevated structures for these carport systems is higher than rooftop systems in most cases and, therefore, Black & Veatch assumed these types of systems would not be considered cost competitive compared to rooftop systems. For this reason, parking lots were not included in the technical screen.

For the purposes of this study, Black & Veatch chose to analyze polycrystalline modules mounted in a fixed-tilt orientation. This is a common technology and mounting orientation and, therefore, considered representative of the other options for characterization purposes.

3.2 GENERAL COST ESTIMATING APPROACH

Black & Veatch identified key factors driving the cost projection of solar in the global, national, and regional markets. Cost projections were developed for both distributed solar in PGE's service territory and utility-scale solar in Oregon. These estimates are specific to the region and based on forecasts for the main solar cost components, including the following:

- PV modules.
- PV inverters.
- Other PV balance-of-system hardware (racking/mounting/trackers, combiner boxes, wiring, transformers, communications and control systems, etc.).
- Grid interconnection.

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[3] Concentrating photovoltaics (CPV) are applicable in locations with high direct insolation. Oregon is not considered an applicable location for CPV technologies, and this technology is therefore not discussed.

[4] Dual-axis tracking systems are not often used for flat plate PV and therefore are not discussed.

- "Soft" costs (land costs, permitting, customer acquisition, engineering, procurement, and construction [EPC] costs, financing, etc.).
- Installation labor costs.

To establish a starting point for the solar PV cost projection, Black & Veatch used proprietary conceptual cost estimating tools to generate bottom-up cost estimates for both rooftop solar and ground-mount utility scale systems for several representative sizes. The conceptual cost estimate tools were derived from Black & Veatch procedures and experience generating and reviewing firm-price bids to engineer, procure, and construct utility scale PV solar. Inputs for the analysis were based on recent quotations for equipment and recent experience regarding labor requirements and reflect projects to be installed in 2015.

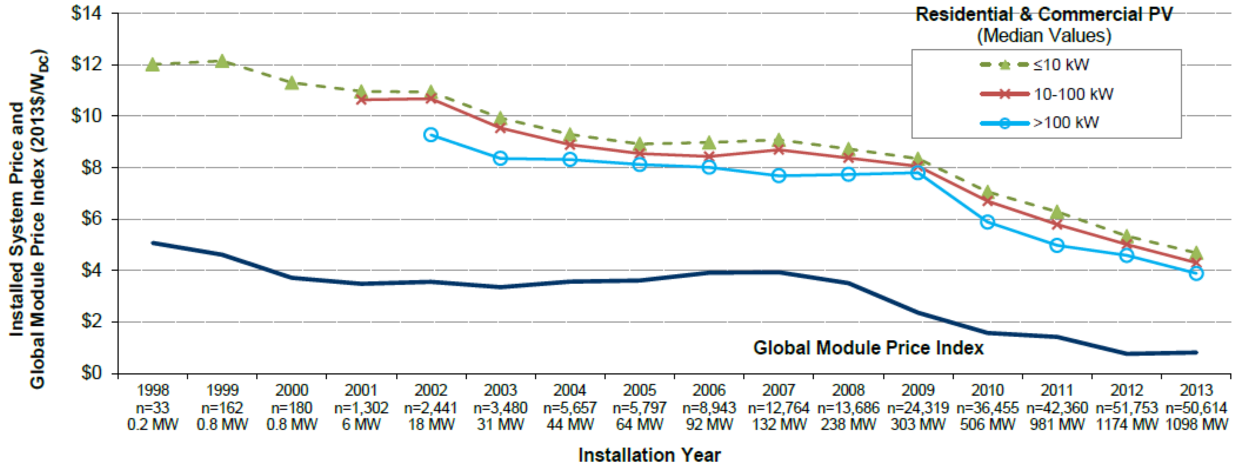
The 2015 costs served as the starting point for forecasted solar PV costs from 2016 to 2035.

3.3 DISTRIBUTED SOLAR PV COST PROJECTIONS

This section provides cost projections for distributed solar PV, namely, rooftop solar systems. Historical and current costs are presented first, followed by Black & Veatch's projections for costs through 2035.

3.3.1 Historical and Present Distributed Solar PV Cost

Since 1998, rooftop PV system prices throughout the United States have fallen on average between 6 and 8 percent per year. The decrease is due primarily to lower module and other equipment costs. This rate of price reduction has increased in recent years. Prices fell between 12 and 15 percent from 2012 to 2013 alone. Rooftop solar prices in Oregon tend to track above the national average and have also dropped significantly since 2008. Figure 3-3 illustrates the installed prices for rooftop solar PV over time.



Note: Median installed prices are shown only if 15 or more observations are available for the individual size range. The Global Module Price Index is SPV Market Research's average module selling price for the first buyer (P. Mints).

Figure 3-3 **Median Reported Installed Prices of Residential and Commercial PV Systems over Time (source: US DOE)**

Oregon prices for residential and commercial customers have also fallen over time as well, as shown on Figure 3-4. This figure shows that since 2007, reported residential PV costs in Oregon have dropped approximately 50 percent from around $9/Wdc to about $4.5/Wdc in 2014. Reported commercial system costs have dropped even further, starting at over $9/Wdc in 2007 and dropping to less than $4/Wdc in 2014.

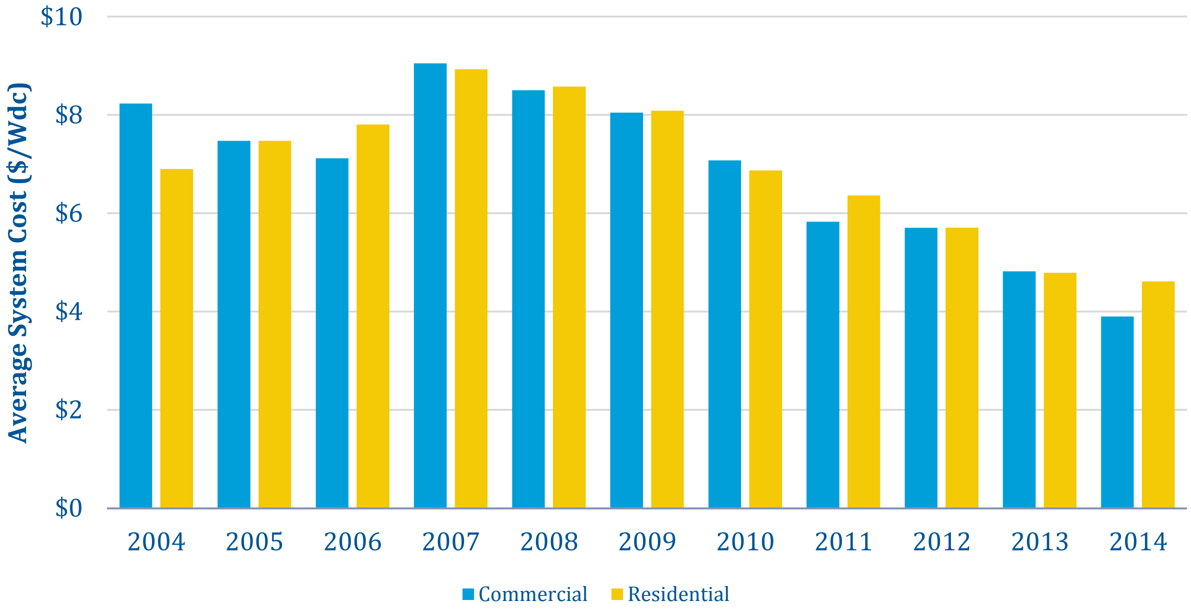


Figure 3-4 **ETO-Funded Installed PV System Average Costs in PGE Service Territory (Data Source: ETO)**

As shown in Figure 3-5, the pace of installations, including both ETO funded and Solar Payment Option (SPO) projects, for residential systems has averaged about 5 MWdc per year for the past 4 years. In contrast, commercial system installation rates have slowed, averaging only about 2 MWdc per year over the past 2 years, after peaking at about 7 MWdc of annual installations in 2012, when the Oregon tax incentive for commercial customers expired.

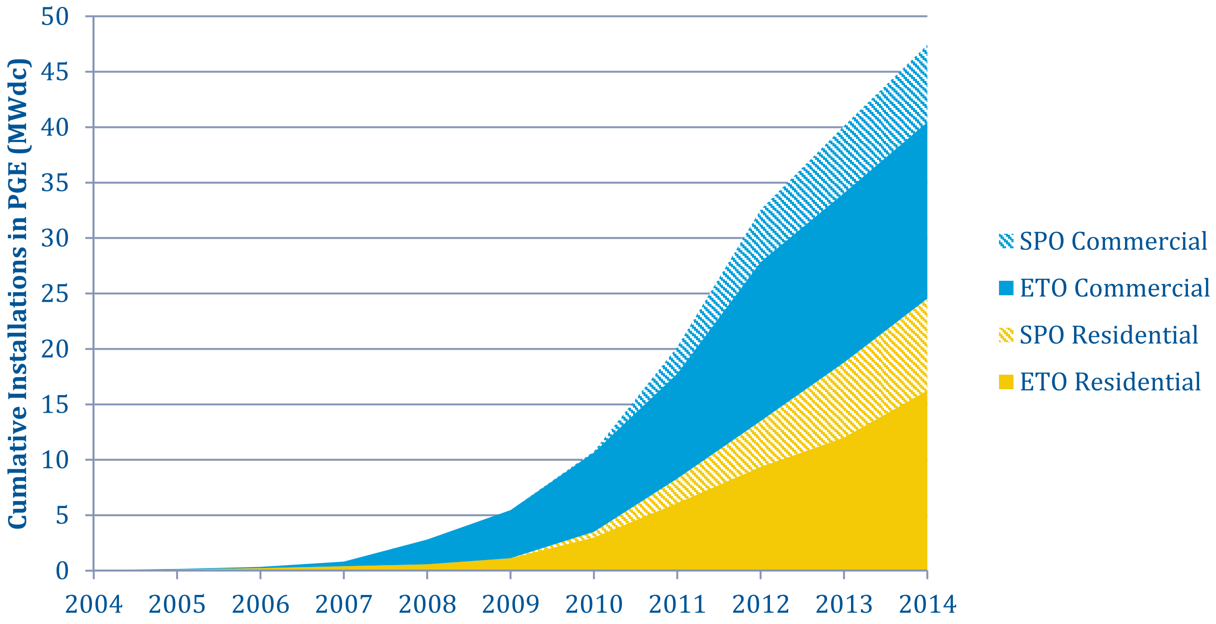


Figure 3-5 ETO Funded and SPO Cumulative Installations in PGE Territory

Interestingly, under the ETO incentive program, third-party owners (TPOs) make up over 80 percent of the capacity installed in 2014 for residential installations and 30 percent of commercial installations. While TPO models are more prevalent, there is insufficient historical data to conclude whether TPO is driving market growth.

The TPOs typically report generically higher cost information to the ETO than direct sales, thus increasing the reported average installation cost of residential systems.[5] Figure 3-6 shows the average system costs for 2014 separately by direct sales customers and TPOs. For the purposes of this study, the direct sale customers are the more relevant comparison, with average system costs ranging from $2.84 to $4.51/Wdc for smaller systems and $3.16 to $3.27/Wdc for large systems.

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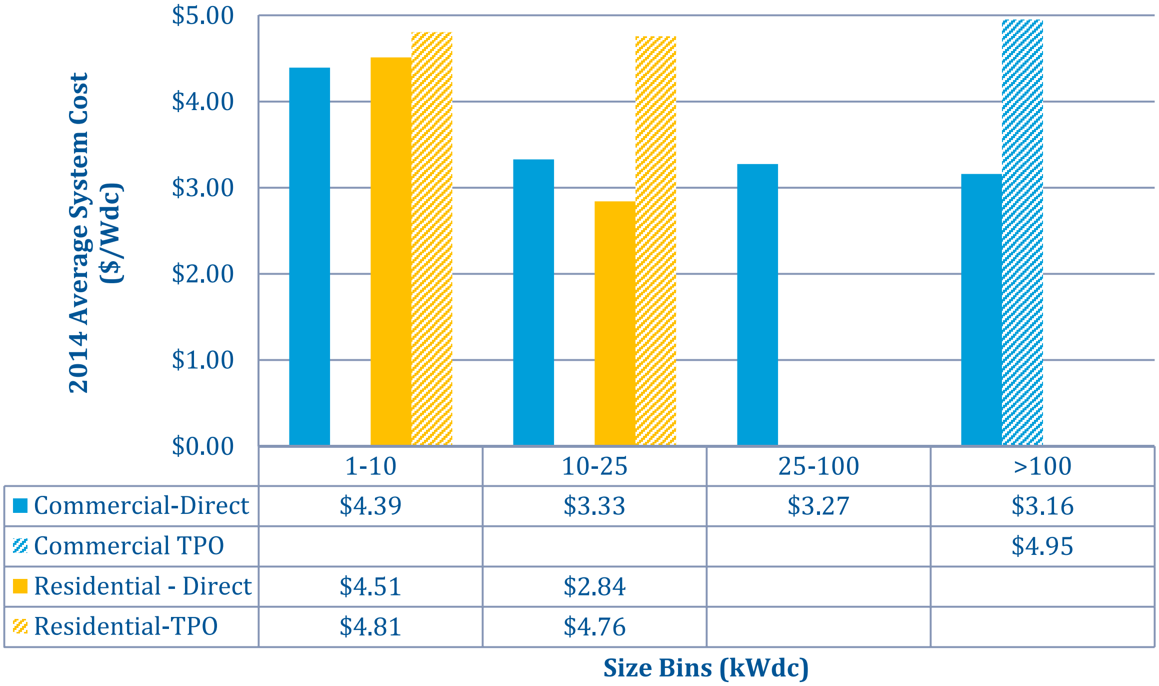
[5] Since TPOs do not sell the solar system to the host, their basis for reporting costs is not as straightforward as direct sales installations. There are a variety of reasons that TPO reported costs are typically higher than direct sales, including the basis used for tax credits, perceived fair market value, etc.



	1-10	10-25	25-100	>100
■ Commercial-Direct	$4.39	$3.33	$3.27	$3.16
▨ Commercial TPO				$4.95
■ Residential - Direct	$4.51	$2.84		
▨ Residential-TPO	$4.81	$4.76		

Figure 3-6 ETO 2014 Reported Installed Costs by System Size (kWdc) and Ownership (Source: ETO)

To estimate current PV costs, Black & Veatch developed a bottom-up cost estimate for distributed solar. This was then compared to market data from the ETO's PowerClerk database to ensure that the estimate was consistent with the actual installed costs being observed in the market. The key design and cost assumptions were based on current market conditions, product availability, and conventional system design, as follows:

- For the purpose of the estimate, typical equipment was assumed to consist of Canadian Solar polycrystalline silicon modules, ABB inverters, and Unirac/Quick Mount (for pitched residential rooftops) or AET Rayport (for flat commercial rooftops) racking or equivalent equipment.
- Current EPC module cost is $0.90/Wdc.
- Average system cost assumes a moderate level of complexity for installation:
  - For residential systems, this is characterized by contiguous arrays, two-story residential roofs, roof pitches between 6:12 and 9:12, and within 50 feet of a 240 volt (V) single-phase service panel/utility meter.
  - For commercial roofs, this is characterized by arrays routed around heating, ventilating, and air conditioning (HVAC) and other rooftop obstructions, flat roofs, and within 250 feet of a single- or three-phase 208, 240, or 480 V service panel/utility meter.

- Estimates of EPC indirect costs were based on Black & Veatch experience and industry-accepted assumptions.
- Other soft costs are based on general industry practice of 50 percent margin above total EPC costs. Soft costs include any permitting fees, administrative costs, financing and contracting costs, design and engineering costs, customer acquisition costs, incentive application fees, interconnection fees, taxes, insurance, contingency, and profit, as well as the costs associated with project delays due to permitting or interconnection issues.

Cost estimates were generated for 4 kWdc (residential), 50 kWdc, and 250 kWdc (commercial) rooftop systems of moderate or "average" difficulty. These sizes fall within the range of typical distributed generation grid-tied systems.

It is important to note that installed PV prices vary widely in Oregon and throughout the United States because of such factors as brand-value, extended warranties, third-party ownership models, and other factors not captured by cost per watt. Prices are also influenced by both consumer savvy and contractor practices. The assumptions provided in this report are considered representative of the market, but actual costs could be significantly above or below these estimates.

Black & Veatch's estimate for rooftop solar PV costs is summarized in Table 3-1. The table provides a breakdown by major components and major soft costs.

Table 3-1 Distributed Solar PV Cost Estimate Breakdown for 2015 Installation (2014$)

PARAMETER	PITCHED ROOF –3.6 KW_{AC} (4 KW_{DC})		FLAT ROOF – 45 KW_{AC} (50 KW_{DC})		FLAT ROOF –225 KW_{AC} (250 KW_{DC})	
	$	$/$\text{W}_{\text{DC}}$	$	$/$\text{W}_{\text{DC}}$	$	$/$\text{W}_{\text{DC}}$
Modules	3,600	0.90	45,090	0.90	225,180	0.90
Inverter(s)	1,380	0.34	10,770	0.21	53,830	0.20
Racking	820	0.21	11,210	0.22	55,980	0.22
Balance of System	880	0.22	3,610	0.07	10,300	0.05
Installation	1,740	0.44	13,120	0.27	50,460	0.23
Total Direct Cost	8,420	2.11	83,800	1.67	395,760	1.60
EPC Indirects	1,550	0.39	9,680	0.20	45,670	0.19
Total EPC Costs	**9,950**	2.49	**93,480**	1.87	**441,430**	1.79
Soft Costs	4,980	1.25	37,390	0.75	178,400	0.71
Total Cost	**14,950**	3.74	**130,870**	2.62	**619,840**	2.50

3.3.2 Projected Distributed PV System Costs

Black & Veatch developed a forecast of future PV system costs. The once seemingly optimistic US Department of Energy's (DOE's) SunShot Initiative targets now appear within reach because of (1) the rapid and prolonged decline in the prices of PV modules and other system components and (2) the potential to reduce labor and other soft costs as demonstrated by best practices in more mature PV markets (e.g., Germany).

Assumptions for Black & Veatch's forecast include the following:

- Installed PV prices will approach the DOE's SunShot Initiative targets in 2025.
- "Learning curve," economies of scale, and incremental cost and technology improvements will continue throughout the projection period at a diminishing rate. As the rate of improvement declines, inflationary pressure will push up on prices in nominal terms.
- No disruptive or revolutionary technology breakthroughs will occur during the projection period, although incremental improvements in module efficiency are implicit in the forecasted cost.
- PV labor, material, and other costs will approach their theoretical minimums between 2030 and 2035.
- Wide variations in installed costs will continue because of differences in contractor operating margins as well as differences in system features not captured by $/W.
- Variations in prices caused by time lags between contract and completion dates are reflected in the model.
- Between 2016 and 2017, Black & Veatch expects a precipitous drop in prices for residential customers if the federal investment tax credit (ITC) is not renewed at the current level of 30 percent, as residential installers will need to offer more competitive pricing to maintain a similar net cost after incentives to customers.

Figure 3-7 shows the Black & Veatch forecast for sample distributed PV systems through 2035. By the end of the forecast period, Black & Veatch forecasts costs will have dropped to between $1.1 to $1.3/Wdc (2014$). Residential system costs are projected to drop by approximately 65 percent, while commercial system costs will drop between 50 and 55 percent. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with the small continued improvements offset by inflationary increases. A table of the annual projection of costs is provided in Appendix A.

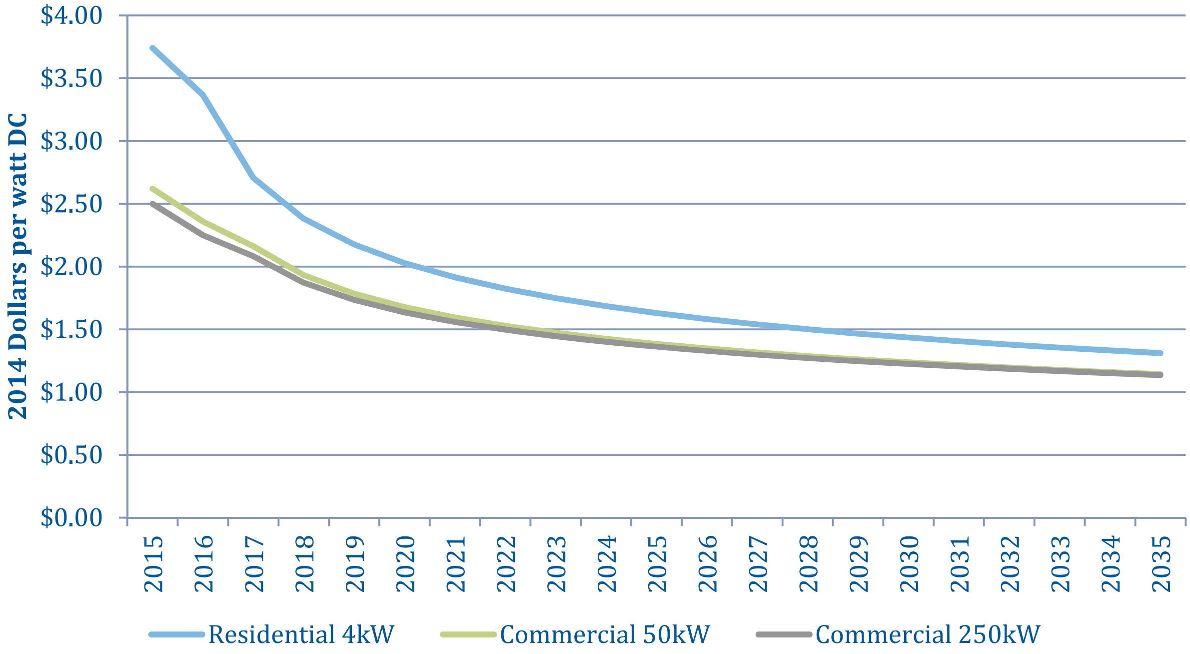


Figure 3-7 **Rooftop Solar PV Cost Projections from 2015 to 2036**

3.4 UTILITY SCALE SOLAR PV COST PROJECTIONS

This section provides cost projections for utility-scale, ground-mount solar systems. Historical and current costs are presented first, followed by Black & Veatch's projections for costs through 2035. This section also provides assumptions for transmission costs.

3.4.1 Historical and Present Utility-Scale Solar PV Cost

As shown on Figure 3-8 ground-mount solar system costs have dropped precipitously in the past 5 years. This has been the result of the mass production of solar PV equipment and the cost reduction realized from the installation of gigawatts of utility scale installations. Cost for ground-mount systems has fallen in Oregon as well. The recent Steel Bridge Solar proposal in Oregon was the lowest reported in Oregon at $1.98/Wdc for a 3.0 MWdc (2.4 MWac) system with a commercial operation date in 2015.[6]

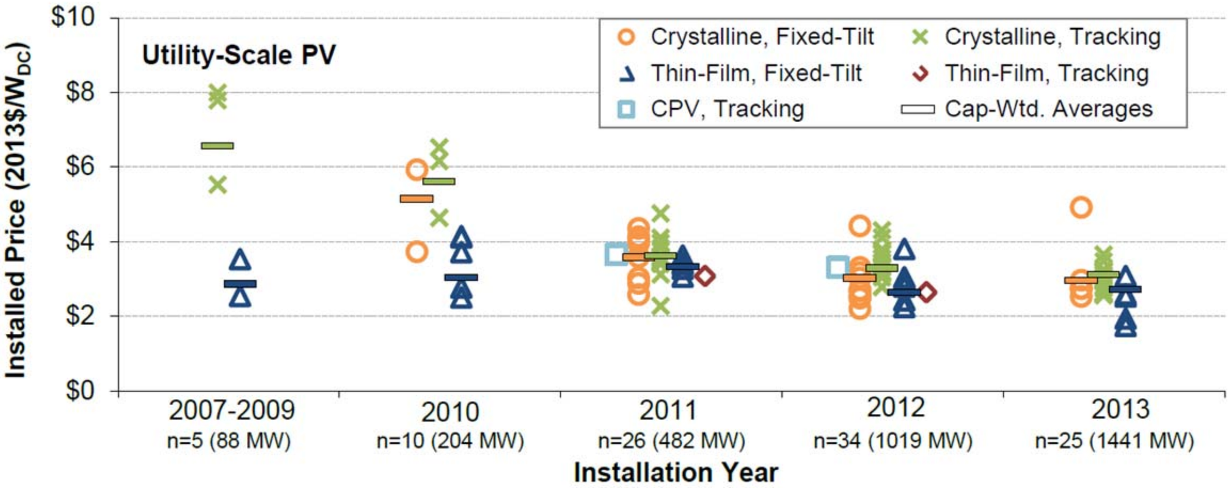


Figure 3-8 Cost Decline of Utility-Scale Solar PV in the US between 2007 and 2013 (Source: Lawrence Berkeley National Laboratory/DOE)[7]

To estimate current PV costs, Black & Veatch developed a bottom-up cost estimate for utility-scale solar. Inputs for the analysis were based on recent quotations for equipment and recent experience regarding labor requirements. The most critical cost input is the assumption of $0.72 per watt for polycrystalline module pricing; this assumption is based on prices after the recent trade case ruling that applied tariffs to Chinese and Taiwanese solar modules.[8] The cost for modules for the larger utility-scale systems is assumed lower than distributed systems because of larger volume purchases.

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[6] "Draft 2015 Annual Budget & 2015-2016 Action Plan –Revisions," Renewable Energy Advisory Council, November 21, 2014 (http://energytrust.org/library/meetings/rac/RAC_meeting_packet_141121.pdf).

[7] "Photovoltaic System Pricing Trends," DOE/LBNL, 2014 (http://emp.lbl.gov/sites/all/files/presentation_0.pdf).

[8] "US slaps trade duties up to 165% on Chinese solar firms," PV Tech, December 19, 2014 (http://www.pv-tech.org/news/us_department_of_commerce_makes_final_ruling_in_china_solar_trade_case).

Cost estimates were generated for 7, 28, and 140 MWdc systems (5, 20, and 100 MWac). These are typical sizes for small and large projects. Typical conceptual designs were used, including a dc capacity to ac capacity ratio of 1:4 meant to optimize performance.

Assumptions for indirect costs were based on Black & Veatch experience and industry-accepted assumptions. Indirect costs considered included EPC profit and contingency as well as owner's project development fees, permitting costs, financing costs, and others. Interconnection and gen-tie costs are not included in these estimates but were separately estimated as discussed later in this section.

The results of the bottom-up cost estimate for utility scale solar is shown in Table 3-2. Additional estimates for single-axis tracking systems are provided in Appendix A.

Table 3-2 Utility-Scale, Fixed-Tilt, Solar PV Cost Estimate Breakdown for Installation in 2015 (2014$)

PARAMETER	5 MW_{AC} (7 MW_{DC})		20 MWAC (28 MW_{DC})		100 MW_{AC} (140 MW_{DC})	
	$	$/$W_{DC}$	$	$/$W_{DC}$	$	$/$W_{DC}$
Modules	5,040,000	0.72	20,160,000	0.72	100,800,000	0.72
Inverters	750,000	0.11	3,000,000	0.11	15,000,000	0.11
Racking and Foundations	1,144,000	0.16	4,576,000	0.16	22,882,000	0.16
Balance of System	939,000	0.13	2,354,000	0.08	9,954,000	0.07
Installation	1,364,000	0.19	4,225,000	0.15	19,059,000	0.14
Total Direct Cost	9,237,000	1.32	34,316,000	1.23	167,694,000	1.20
EPC Indirects	2,688,000	0.38	8,865,000	0.32	38,404,000	0.27
Total EPC Cost	11,925,000	1.70	43,180,000	1.54	206,098,000	1.47
Owner's Costs (15%)	1,789,000	0.26	6,477,000	0.23	30,915,000	0.22
Total Cost	13,714,000	**1.96**	49,657,000	**1.77**	237,012,000	**1.69**

3.4.2 Projected Utility-Scale Solar PV Costs

Black & Veatch developed a forecast of future PV system costs for utility-scale systems. Cost projections are based on Black & Veatch expectations and established industry roadmaps. PV solar costs have dropped dramatically over the last 10 years, surpassing the expectations of even the most optimistic analysts. Costs are expected to continue to fall, but market pressures are changing, and the cost reduction potential may be reaching theoretical limits.

The projections incorporated Black & Veatch's understanding of the technical limitations on cost reduction, the examples of more mature solar markets such as those that exist in Germany, and credible studies of cost reduction potential such as those performed for the DOE's SunShot Initiative.

Figure 3-9 shows the Black & Veatch forecast for typical utility-scale PV systems through 2035. By the end of the forecast period, Black & Veatch forecasts costs will have dropped to less than $1/Wdc for larger fixed-tilt systems. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with the small continued improvements offset by inflationary increases. A table of the annual projection of costs for both tracking and fixed-tilt systems is provided in Appendix A.

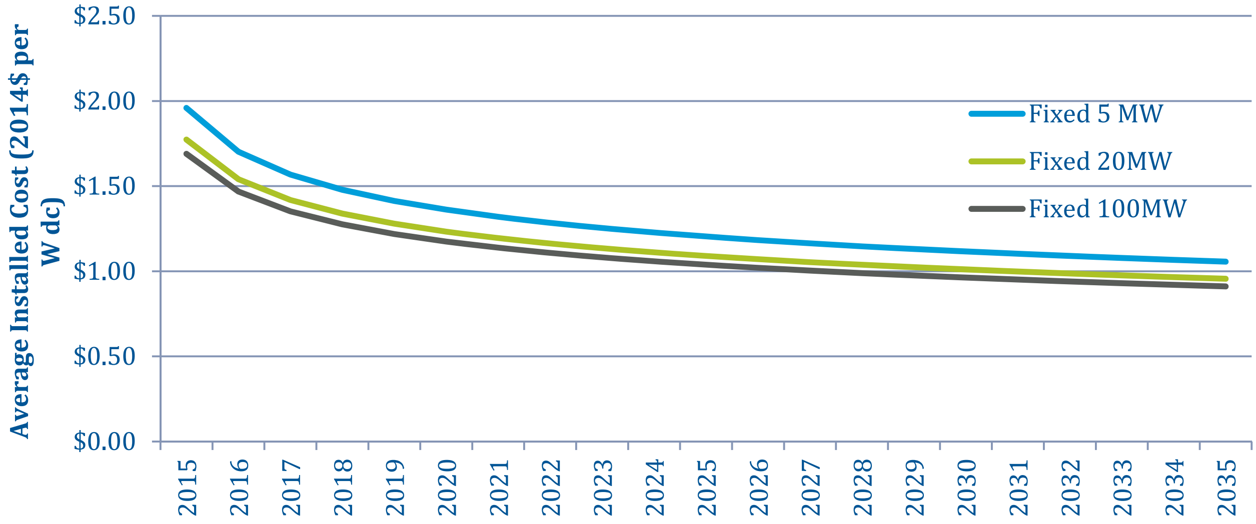


Figure 3-9 Utility-Scale, Fixed-Tilt Solar PV Cost Projections from 2015 to 2035

3.4.3 Transmission Cost Assumptions

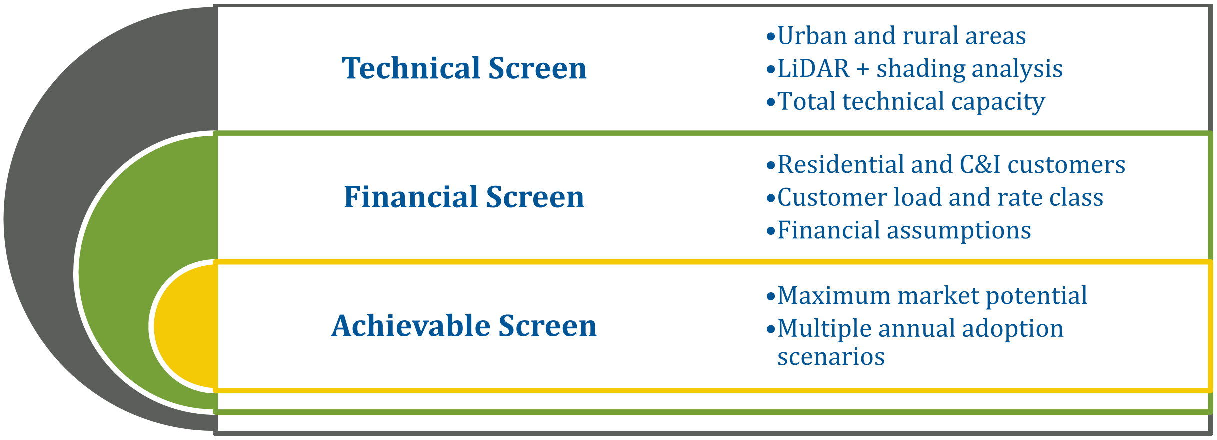
Larger utility-scale PV systems will likely connect to the transmission system and will incur costs for interconnection, including substation and generation tie-line costs. These costs are in addition to the PV plant costs discussed in the previous section. Black & Veatch recently provided updated transmission cost estimates and a transmission project cost estimation tool to the Western Electricity Coordinating Council (WECC) as part of its long-term planning process. These data were updated to be Oregon-specific and used for this financial screen. For utility-scale solar PV systems, Black & Veatch assumed that either an onsite substation would need to be built, or upgrades to a nearby utility substation would be required. Therefore, substation costs were applied to each project site, based on the size and voltage of the transmission line or substation. Generation tie-line (gen-tie) costs were also applied to each project based on its proximity to a transmission line or utility substation, the closer of the two.

Table 3-3 Substation and Gen-Tie Line Cost Estimate Breakdown (2014$)

PARAMETER	< 100 KV (5 TO 50 MW)	115 KV (5 TO100 MW)	230 KV (20 TO 250 MW)	500 KV (100 TO 250 MW)
Substation ($million)*	$3.18	$3.38	$10.0	$19.5
Generation Tie-Line ($million/mile)	$1.5	$1.5	$2.0	$3.5
*Primary components in substation cost include a transformer and circuit breakers.				

4.0 Distributed Solar PV Potential Assessment

Black & Veatch assessed the potential for distributed solar PV installed on customer rooftops within PGE's service territory. Black & Veatch utilized multiple innovative tools and processes to identify the solar PV distributed generation potential. The technical, financial, and achievable screens can be summarized as follows:



1. **Technical Screen:** The technical screen quantifies the amount of useable rooftop space on individual buildings across the urbanized areas of PGE's service territory. Technical potential is constrained to those roof areas that receive adequate solar resource as defined by Oregon's eligibility requirements for tax credits and incentives. The rooftop space is then translated to total capacity (MWdc). Black & Veatch then extrapolated the analysis outside the urban areas to estimate the total technical potential in PGE's service territory.
2. **Financial Screen:** For the financial screen, site-specific characteristics were developed to calculate the expected payback of individual buildings, accounting for solar profile, project size, and customer type. The financial screen limits sites to paybacks of 20 years or fewer for both residential and commercial customers. Detailed financial analysis was performed for hundreds of thousands of sites in the years 2016 and 2035, under two rate increase scenarios.
3. **Achievable Screen:** Black & Veatch developed estimates of achievable potential on the basis of the financial screen results and a range of market adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch sought to identify the higher and lower bounds of solar adoption potential over time using two approaches: bottom-up and top-down.

4.1 TECHNICAL SCREEN

The technical screen attempts to capture the amount of useable rooftop space on individual buildings across the PGE service territory that receives an adequate level of solar resource for development. Adequate resource is defined as areas that receive sufficient solar resource to meet eligibility requirements for ETO incentives and state tax credits, which require systems to have a Total Solar Resource Fraction (TSRF) of 75 percent or higher. This essentially means that a system placed at that site must perform 75 percent or better than a system ideally oriented, without shading, at the same site. Drivers that impact the solar resource on the plane of a surface include tilt of the roof, azimuth (i.e., compass heading), and surrounding obstructions (i.e., trees and buildings) that can cause shading at the site.

4.1.1 Approach

Black & Veatch developed a detailed and novel approach to evaluate technical potential for solar down to the individual customer level. The first step in the process was to use geospatial data (data gathered with remote sensing instruments) and proprietary analysis methods. Black & Veatch used the rich LiDAR data available for PGE's service territory. Black & Veatch focused on urban areas, as these are generally land-constrained and more amenable to rooftop installations. There were a few areas where LiDAR data are not available and, therefore, Black & Veatch was not able to assess solar PV potential using the LiDAR approach. The urban areas shown in green on Figure 4-1 were included in the LiDAR assessment. While the green areas cover less than 50 percent of the PGE territory, due to the much higher population density in these areas, about two-thirds of the estimated technical potential is within the green areas. For other areas, technical potential estimates were developed by extrapolating the results from similar parcels from the LiDAR study.

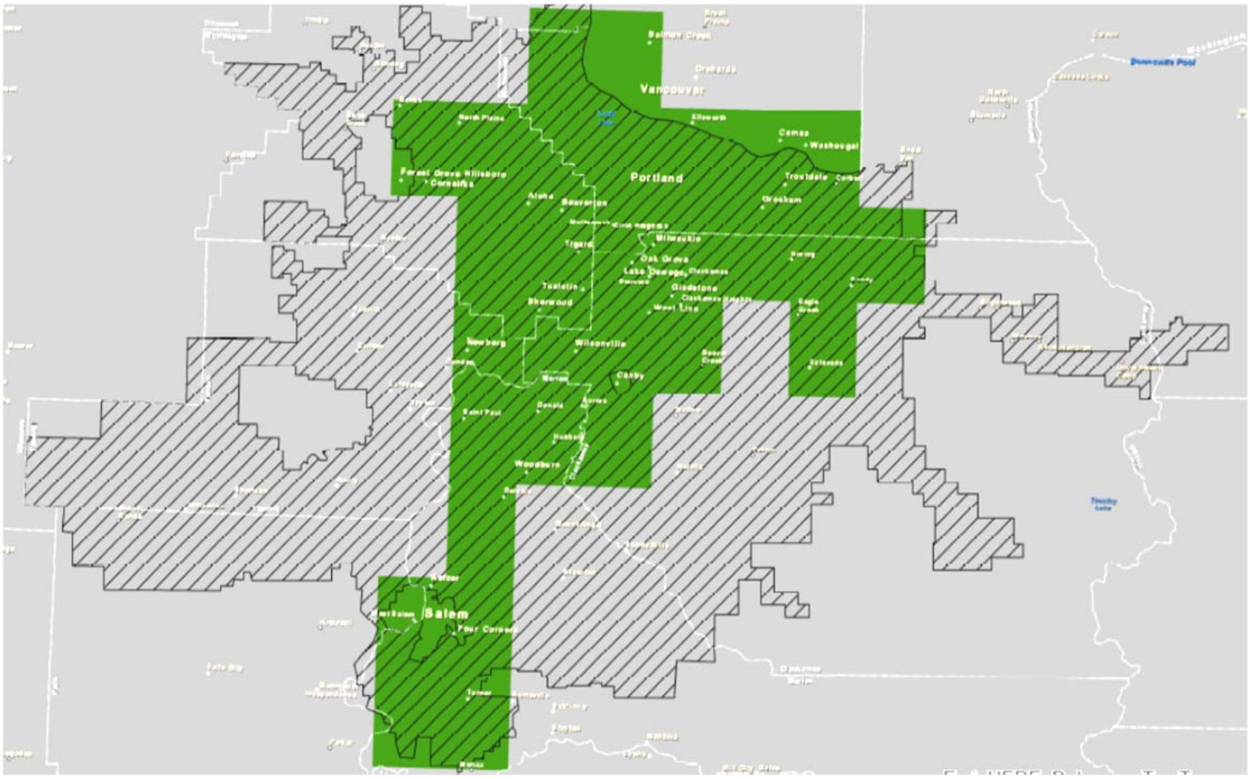


Figure 4-1 Available LiDAR and Building Footprint Data for PGE Service Territory

The tools and processes used in this analysis are extremely powerful, as they are used to evaluate individual rooftops for available roof area and appropriateness for solar development as well as the respective tilt and azimuth of each roof plane. The tool also accounts for the impact of shading from surrounding trees and buildings as it assesses the solar resource at each square foot on a roof each hour over a year. The analysis was able to identify the effective solar resource (irradiance) that reaches the plane of a roof, so any areas that did not meet the TSRF requirement were excluded.

Rooftops smaller than 400 square feet were removed to avoid detached garages, sheds, and other structures that are likely not structurally sound or connected to load. Using parcel data, Black & Veatch was able to differentiate between residential and commercial buildings.

Figure 4-2 illustrates this process. The image on the left shows several residential roofs and their associated orientations (tilt and azimuth) as well as shading sources (namely, trees and buildings). The image on the right shows the solar resource incident on these roofs, accounting for their orientation (i.e., south facing roofs have higher resource compared to north facing roofs). This image also clearly shows the effect of shading from trees. Red indicates good resource, while blue indicates poor resource. The mostly blue building in the center right is shaded by trees on the southern building perimeter.

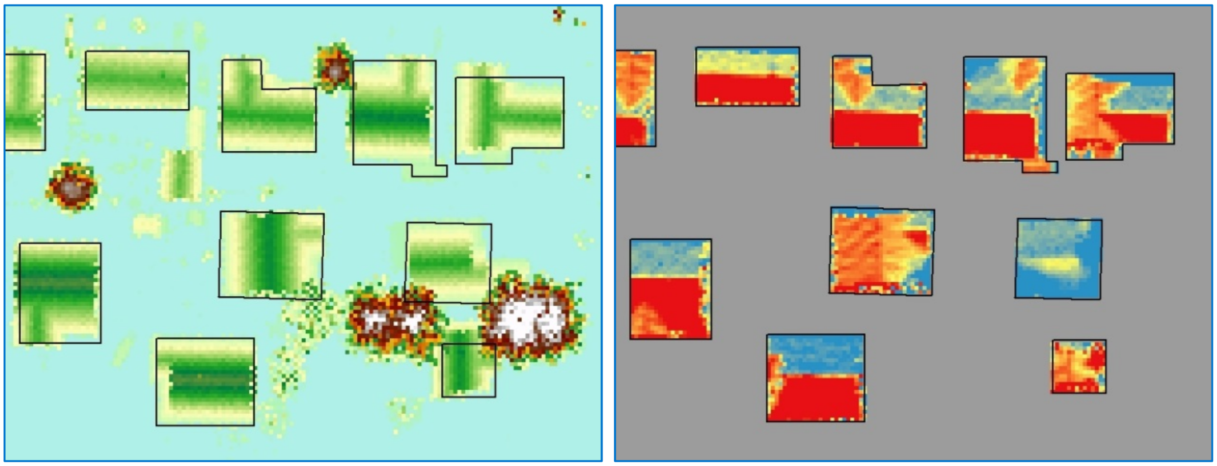


Figure 4-2 Sample Rooftop GIS Analysis, Residential Area

The process works similarly in residential or commercial areas. In contrast to the residential area shown on Figure 4-3, Figure 4-4 show the process applied in central Portland near the Pioneer Courthouse. The numbers represent average building height. Most of the shading in this area is from adjacent tall buildings or obstructions on the roof.

Figure 4-3 Sample Rooftop GIS Analysis, Central Portland

Following these initial processes, Black & Veatch programmed the ArcGIS tool to step through a series of criteria to select roof areas that would be considered technically feasible. These are described below and shown on Figure 4-4:

1. Isolate buildings from building footprint data. Identify roof planes and tilt and azimuth of each roof plane and account for appropriate setbacks.[9]
2. Filter roof areas that did not meet the TSRF metric of 75 percent or better. Areas in black in Figure 4-4 passed the TSRF metric. As would be expected from the TSRF requirement, most of the selected roofs were oriented southward or were flat roofs with minimal shading.
3. Seek a minimum contiguous area of 100 square feet on each roof plane to accommodate a reasonably sized solar PV system.
4. Apply a geometric constraint that at least one edge of the contiguous area must have a 4 foot length to fit a solar panel.

Once the technically feasible roof area was calculated, Black & Veatch converted the area to equivalent solar dc capacity. The conversion factors accounted for typical module dimensions, ratings, and orientations applicable in rooftop systems. For tilted roofs, Black & Veatch used a conversion factor of 10 Wdc per square foot (sq ft) because the roof systems can be flush-mounted. On flat roofs, systems are typically tilted slightly with spacing between rows to avoid shading. The conversion factor for flat roofs was assumed to be 5.8 Wdc per sq ft.

The LiDAR analysis focused on designated urban areas and was not performed for rural areas with low density of buildings. For these areas, parcel data were used to scale results from urban areas to the remainder of PGE's service territory. The scaling factors were derived from counting the parcels in areas that were analyzed versus areas that were not analyzed. The scaling factors by property type are shown in Table 4-1

Additional details of the Black & Veatch approach, assumptions, and analysis can be found in Appendix B.

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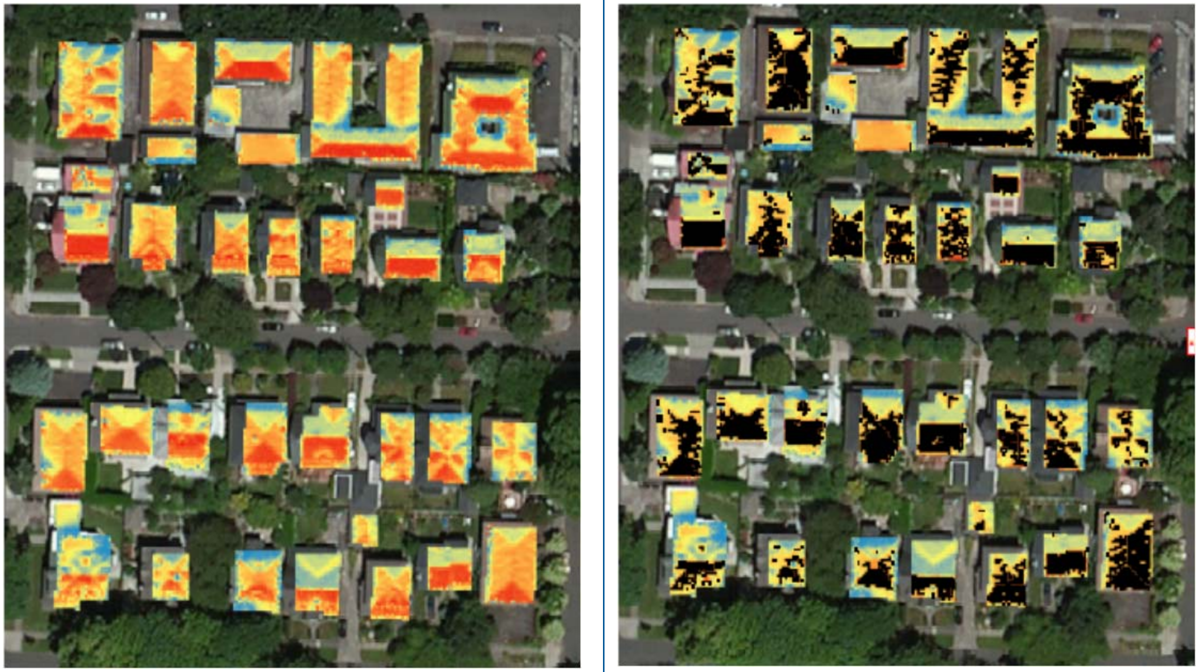
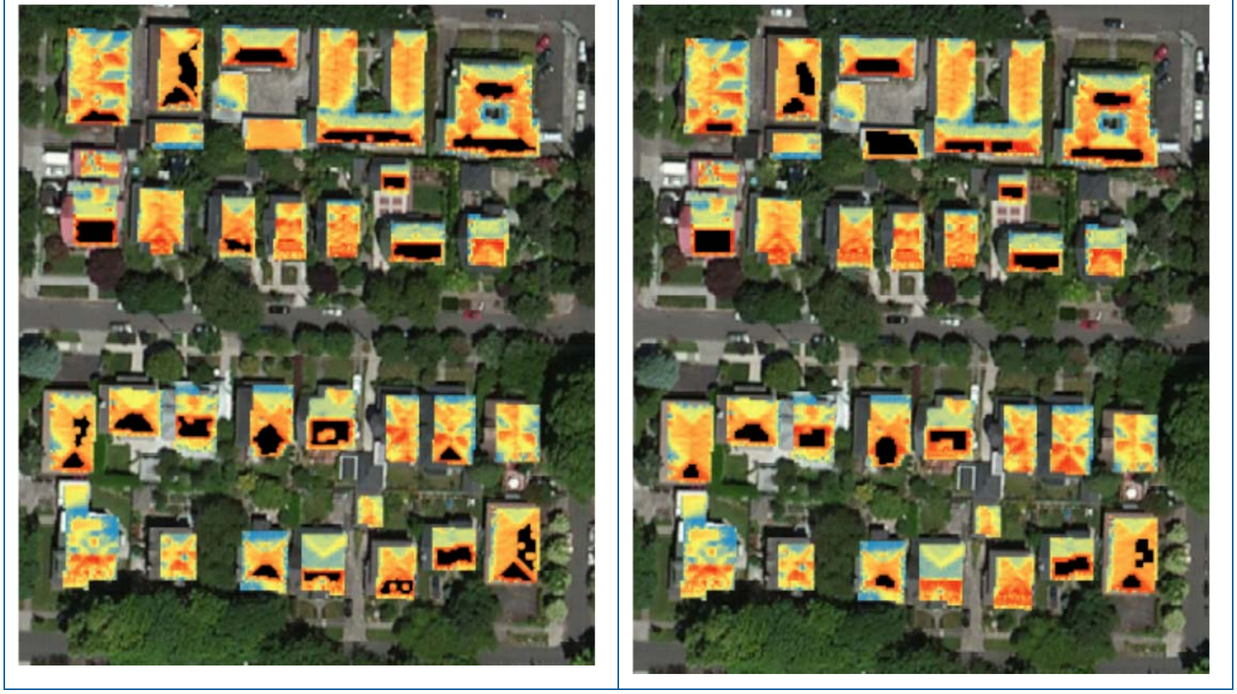
[9] Residential system setbacks – 2 feet from all edges.
Commercial system setbacks – 6 feet around the perimeter of the roof.



Step 1: Isolate Building Footprint

Step 2: Filter for TSRF Metric



Step 3: Locate Minimum Contiguous Areas

Step 4: Geometric Constraint

Figure 4-4 Rooftop Assessment Criteria Filters

4.1.2 Results

The analysis evaluated 1.2 billion square feet of rooftop space representing over 400,000 buildings. Of these buildings, single-family residential rooftops that passed the technical criteria totaled over 451 MWdc, and multi-family residential buildings represented another 125 MWdc. Commercial and industrial buildings represented over 1,162 MWdc, while public (government) roofs totaled 62 MWdc. The total technical potential of the areas assessed was 1,800 MWdc. After scaling up to cover the entire PGE service territory, the total technical potential amounted to 2,810 MWdc. Only about 30 percent of this amount is residential, the rest is composed of commercial, industrial, and public/semi-public properties. A summary of the technical screen results is provided in Table 4-1.

Table 4-1 Identified Distributed Solar PV Technical Potential

PARAMETER	LIDAR-ASSESSED AREA TOTAL CAPACITY (MWDC)	SCALE-UP FACTOR	PGE SERVICE TERRITORY TOTAL CAPACITY (MWDC)
Single-Family Residential	451	1.4	631
Multi-Family Residential	125	1.3	167
Commercial	586	1.5	874
Industrial	575	1.5	869
Public/Semi-Public	62	4.3	270
Total	**1,800**		**2,810**

It is important to note that the technical potential estimate is based on assessment of the current building stock within PGE's territory. New construction could cause the technical potential to increase over time. A number of other factors could also influence this potential over time, including the following:

- Modifications to the existing building stock.
- Growth/removal of trees and other shading sources.
- Improvements in solar panel efficiency.
- Changes in permitting/zoning requirements and restrictions.
- Innovations in mounting structures, such as lower cost solar carports.

Black & Veatch recommends that PGE regularly update the technical potential estimate and consider these factors in future studies.

4.2 FINANCIAL SCREEN

The second step in the process was to apply a series of financially-related screens for estimating solar PV potential in the PGE service territory.

Black & Veatch performed financial calculations by customer site, using the technical assessment for each individual customer site. Site-specific satellite-based meteorological data[10] was used to generate hourly solar PV output profiles for each site. This solar profile then was compared to a customer's hourly load profile. Projects were resized to match designated load profiles, so systems would not over-generate under the net metering tariff. Corresponding utility rates and incentives were included in the calculation of the payback of solar PV for each customer site.

To perform all of these calculations, Black & Veatch developed a DG financial engine based on the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM). It comprises several modules, including the following:

1. PV System Performance -PVWatts.
2. Customer Rates and Load.
3. Financial Analysis.

Black & Veatch was able to develop an automated calculation approach using cloud computing to process hundreds of thousands of customer sites in a highly automated manner. Black & Veatch leveraged cloud computing to aid in reducing processing time for all production and financial modeling of individual buildings of PGE's service territory, which is an extremely data-intensive endeavor.

In addition to the financial analysis, multiple factors were considered in this screening step. Multi-family dwellings were excluded because there are fundamental challenges in installing systems for shared usage. Since installing solar PV on rooftops is a long-term commitment that both residential and commercial renters are unlikely to pursue, ownership factors were applied to the total estimated potential to represent the portion of the property type that were occupant-owned.

4.2.1 PV System Performance

Within SAM, Black & Veatch selected the PVWatts tool to model solar system output for a polycrystalline solar PV technology. It uses inputs that describe a system's dc capacity, array orientation, mounting type, and system losses. These input assumptions were extracted during the technical screen step. Along with PVWatts, Black & Veatch utilized Clean Power Research's hourly solar resource dataset, SolarAnywhere. These data are available for Oregon on a 10 kilometer (km) by 10 km grid, and each building was matched to the respective grid for the appropriate dataset. Black & Veatch developed system assumptions that are representative of typical system parameters or losses seen in the industry for input into SAM. These assumptions are summarized in Appendix B.

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[10] These data were provided by Clean Power Research. The dataset is called SolarAnywhere.

4.2.2 Customer Load and Rates

To calculate the bill savings of solar to a customer, SAM is able to incorporate a customer's hourly load shape over a year as well as a particular utility rate structure as part of its utility rate and customer load modules. Based on the technical screen, buildings were segmented into residential and commercial customers. Without knowing what individual customer loads were, Black & Veatch utilized representative average load shapes, provided by PGE, for each customer rate class.[11] Residential and industrial customers were identified through their respective parcel classifications.

Building loads of commercial customers were not readily available, so building floor space was used, reported in tax parcel data, to classify commercial customers into appropriate rate classes. Black & Veatch developed representative ranges of building floor space using Commercial Building Energy Consumption Survey (CBECS) from the Energy Information Administration (EIA) specific to Oregon. Table 4-2 summarizes the rate classes, demand, and floor space equivalents assumed.

Table 4-2 Customer Loads and Rate Classes

PGE RATE SCHEDULE	CUSTOMER CLASS	DEMAND RANGE (KW)	PARCEL CLASS	BUILDING FLOOR SPACE (SQ FT)
7	Residential	N/A	RES	N/A
32	Small Commercial	< 30	COM	0 to 6,000
83	Medium Commercial	31 - 200	COM	6,001 to 36,000
85	Large Commercial	201 - 4000	COM	36,001 to 728,000
89	Industrial	> 4000	IND	Over 728,000

Furthermore, given that Oregon's net metering rules do not compensate customers for annual energy production that exceeds annual consumption, PV systems were resized when they exceeded the respective building's annual load assumption.

4.2.3 Financial Analysis

NREL's SAM was used to analyze the financials for each customer site. SAM's financial model calculates a project's cash flow over an analysis period that a user specifies. The cash flow captures the electricity bill savings from a PV system and accounts for incentives, cost of installation, operation and maintenance, taxes, and financing assumptions. It is important to note that SAM calculates net energy savings differently for residential and commercial customers. For residential customers, the full energy savings annually is accounted for in the net cash flow calculation. However, for commercial customers, since electricity charges are an expense that is tax deductible as part of regular business operations, any reductions to their electricity bills (i.e., bill savings) will need to be adjusted by the commercial customer's effective federal plus state tax rate. In other words, the annual net bill savings is reduced by up to 40 percent for Oregon businesses. On the other hand, for public and non-profits that are tax-exempt, they are not able to take advantage of tax credits and accelerated depreciation treatment, so their upfront installed costs are higher.

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[11] The analysis could be improved in future work by using real customer load data for each site.

Black & Veatch chose to assess the identified systems using payback period as the financial metric because it is widely understood and is taken into account by customers considering a solar PV system on-site. Payback normalizes for system sizes since it compares total system cost to ongoing annual savings. Payback is also a common metric for adoption analysis, which is an input to the achievable screen.[12] Black & Veatch acknowledges that third-party leasing of systems, where customers do not have to pay an upfront cost, are becoming more prevalent in PGE's service territory, as evidenced by recent installations. However, given the observed pricing behavior of third-party participants, such as Solar City, resulting in negative earnings, it was not possible to model TPO financials in a reasonable manner,

For the purposes of calculating the payback period as the financial metric, Black & Veatch assumed a cash upfront purchase (no loans), 20 year project life, and an inflation rate of 2 percent, consistent with historical Consumer Price Index (CPI) changes. For ongoing operations and maintenance (O&M) costs, Black & Veatch assumed minimal maintenance costs on the part of the customer and no property taxes, as Oregon currently allows solar property to be exempt from property taxes. The primary component of the O&M cost is associated with inverter replacement some time during the life of the project. This cost was amortized over the life of the project. Refer to Table 4-3.

Table 4-3 Distributed Financial Assumptions

INPUTS	ASSUMPTION	
	RESIDENTIAL	COMMERCIAL/INDUSTRIAL
Ownership Structure	Customer-owned	Customer-owned
Federal Income Tax Rate (%)	25	35
State Income Tax Rate (%)	9	7.6
Sales Tax	Exempt	
O&M Cost ($/kW-year)	15	10

For distributed solar systems in Oregon, there are several federal and state solar PV incentives available to residential and commercial customers. Some of these incentives are due to expire in the near-term but there is a possibility of renewal, or renewal at a different amount. The ETO incentives are adjusted annually, both in total funding and incentive levels. Additional background information can be found in Appendix C.

In any case, there is significant uncertainty regarding the future availability of these incentives, both at the federal and state levels. Rather than testing various combinations of projected solar cost decline and incentive assumptions for 2016, Black & Veatch focused on the benefit/cost ratio to customers, similar to the Participant Test approach.[13] Since the ETO has the flexibility to adjust incentives according to market changes, whether it is system cost declines or changes to state tax

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[12] The payback metric used in NREL's adoption surveys is a non-discounted payback, consistent with this report.

[13] The Participant Test derives from energy efficiency measures and is calculated as the net present value (NPV) of total benefits over the NPV of total costs. Benefits consist of bill savings, incentives, and other avoided fuel costs. Costs include customer outlays for initial capital costs and ongoing maintenance of the PV system.

incentives, the more critical component is the benefit/cost ratio to customers. Based on 2014 system costs and available incentives, the benefit/cost ratios for representative residential and commercial installations were calculated to be approximately 1.2 and 1.1, respectively. Refer to Table 4-4.

Table 4-4 Benefit/Cost Ratio for Representative Systems in 2014

	CUSTOMER TYPE	
	RESIDENTIAL	COMMERCIAL/ INDUSTRIAL
Representative System Size (kWdc)	4	100
System Cost ($/Wdc)	4.50	3.20
Accelerated Depreciation	None	5-years MACRS
Federal Incentives	30% of total installed cost	
State Incentives	$1.90/W, 50% of installed cost or $6,000, whichever is less and rolled out over four years up to a max of $1,500 disbursed per year	None*
ETO Incentives ($/Wdc)	0.95	1.08
O&M ($/kW-year)	15	10
Calculated Benefit/Cost Ratio	1.3	1.1
Simple Payback (years)	5	4

MACRS = Modified Accelerated Cost Recovery System.

Notes:

*Even though there is a state renewable energy grant for businesses, it is not possible to estimate the level of award since the grant program is competitively bid and is available to all renewable energy technologies, not just solar.

Based on the benefit/cost ratios calculated for 2014 systems, Black & Veatch estimated what the 2016 ETO incentive for residential and commercial customers would need to be, given the forecast of solar costs in 2016, to maintain a similar level of benefit/cost ratio. Since both the federal ITC and Oregon tax credits for residential customers will still be available in 2016 and Black & Veatch forecasted a steep drop in residential system costs, it was determined that no ETO incentives were needed to maintain the benefit/cost ratio for residential customers. Commercial customers, on the other hand, do not have the benefit of an Oregon tax credit. What is available is the Oregon business grant, but that is a competitive auction open to all renewable energy technologies, thus highly unpredictable as a source of funding. Therefore, while Black & Veatch forecasted a significant drop in commercial system costs by 2016, some level of incentives would still be needed in 2016 to maintain the benefit/cost ratio as experienced in 2014. Black & Veatch assumed a 50 percent reduction to 2014 incentives for commercial customers.

The incentive assumptions for 2016 are described in Table 4-5.

Table 4-5 Distributed Generation Incentive Assumptions for 2016

INCENTIVE	CUSTOMER TYPE	
	RESIDENTIAL	COMMERCIAL/INDUSTRIAL
Accelerated Depreciation	None	5 years MACRS*
Federal Incentives	Investment Tax Incentive (ITC): 30% of total installed cost	
State Incentives	$1.50/W, 50% of installed cost or $6,000, whichever is less and rolled out over 4 years up to a max of $1,500 disbursed per year	None
ETO Incentives**	No incentives necessary	(Half of 2014 Incentives) 0-25 kW: $0.65/W 26-250 kW: $0.65-$0.36/W Max incentive per customer is $90,000

Notes:

*By law, the depreciation cost basis for MACRS is reduced by 50% of the ITC.

** The ETO incentives were estimated to maintain a benefit to cost ratio for sample residential and commercial projects under ETO's program in 2014.

For the 2035 test year, Black & Veatch assumed that no incentives would be available, except for the 5 year accelerated depreciation. By 2035, it is assumed that the market will be mature enough that incentives and subsidies are no longer necessary.

Incentives have long been an important part of the financials of PV, and Oregon has had some of the highest incentives for solar PV in the country. For example, the combined federal, state, and ETO incentives can reduce the installed cost of PV in Oregon by about 55 to 75 percent. This strongly influences the payback of systems in 2016. In contrast, the payback for systems in 2035 is tied to the more fundamental financials of the systems, including capacity factor, capital cost, and rate structure.

To illustrate the impact of incentives on net cost to customers, Figure 4-5 compares the modeled installed cost curves for 2016 and 2035 residential systems in real 2014$ by system size. Figure 4-6 shows similar information for commercial systems. The graphs also show the resulting net capital cost to residential and commercial customers after incentives. The combinations of applicable incentives (Federal ITC, MACRS, Oregon tax credit, and ETO incentives) in 2016 for residential and commercial customers tend to distort the net cost to customers, depending on the size of the system. For example, the 2016 residential net cost start at about $1,160/kW for a 1 kW system dips down to $830/kW for a 4 kW system, and then rises to $1,600/kW for a 12 kW system. The shape of the 2016 curve is due to the incentive limitations defined by the Oregon tax incentive program. Costs in 2035 are generally higher than the 2016 net cost after incentives. For example, while the net cost for a 4 kW system in 2016 is $830/kW, the same system in 2035 is $1,350/kW – about 60 percent higher.

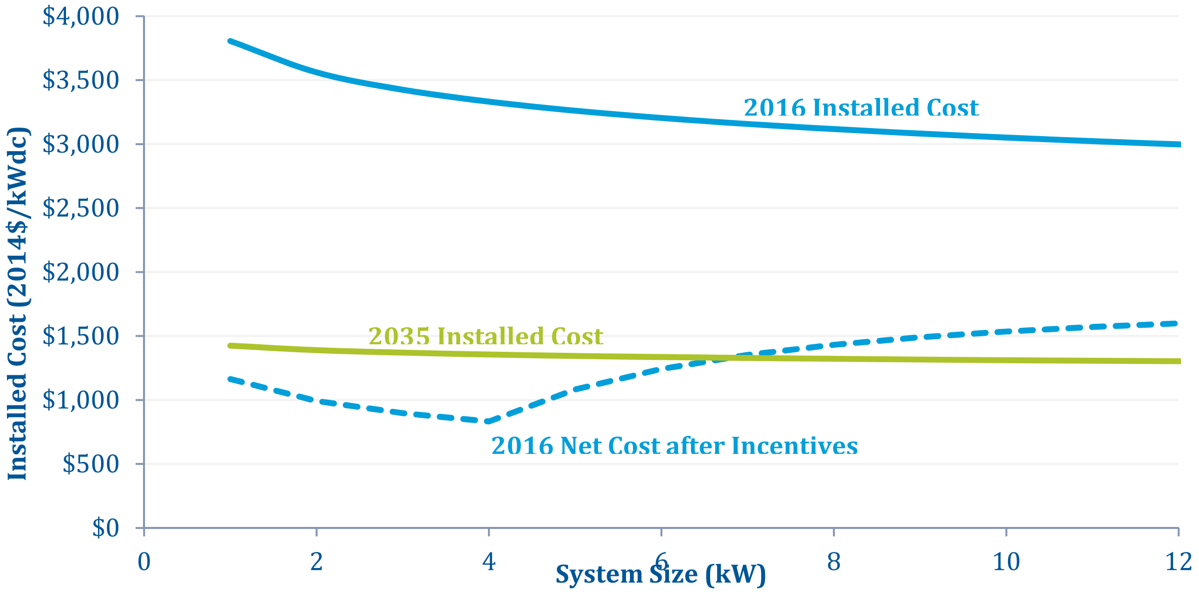

Figure 4-5 Comparison of Installed Residential PV Costs by System Size in 2016 and 2035

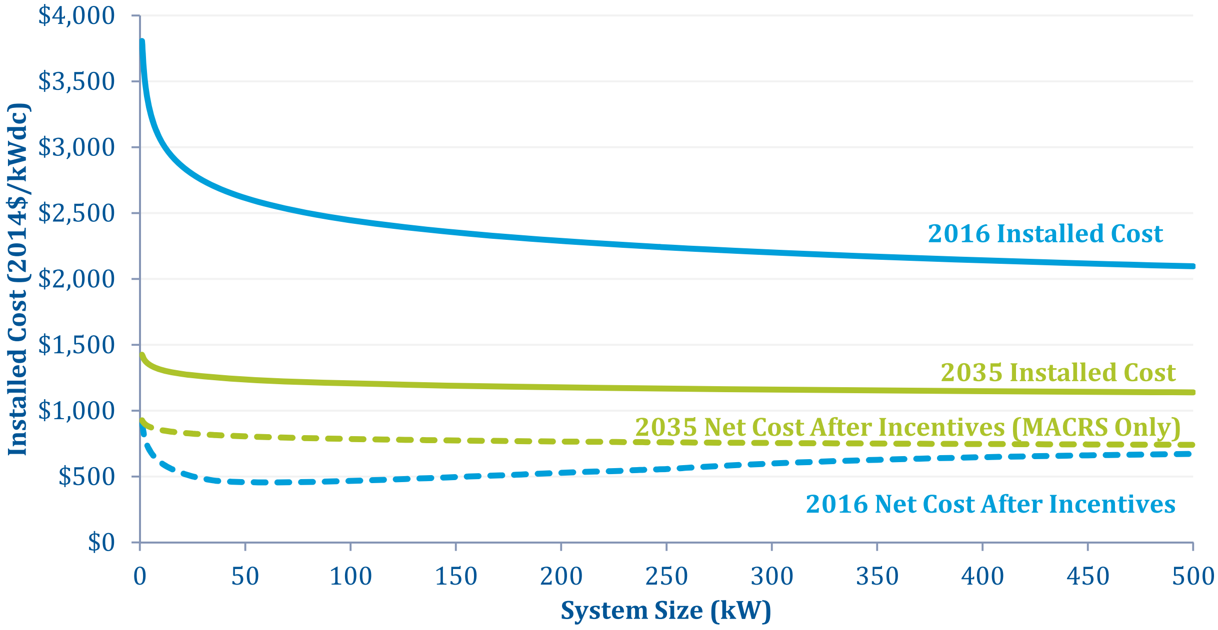

Figure 4-6 Comparison of Installed Commercial PV Costs by System Size in 2016 and 2035

As shown on the commercial graph, the 2016 net cost declines to as low as $455/kW for a 60 kW commercial system and then rises to $670/kW for a 500 kW system. For commercial customers, the net capital cost in 2035 (after accounting for MACRS only) is significantly higher than the 2016 net cost for most systems. For both residential and commercial systems, costs for most systems installed in 2035 are assumed to be higher than the net costs of systems installed in 2016 with incentives. While system costs are projected to decline 50 to 65 percent over this period, the loss of the lucrative incentives is too much. These distortions caused by incentives will appear in the payback calculations in the financial analysis.

4.2.4 Financial Screen Cases

To model the financially viable potential over the study period (2016 to 2035), Black & Veatch first calculated the payback for sites at the beginning and end points of the period. For the 2016 cases, this case included all incentives that are available to solar by customer type including federal investment tax credit (ITC@30%) and accelerated depreciation, Oregon state tax credit for residential customers, and ETO funding. The 2016 case used the forecasted installed cost in 2016. The 2035 cases assumed no incentives would be available except for accelerated depreciation and included the 2035 forecasted installed cost. These two cost years were tested under utility rate increase conditions of CPI and CPI+1.

Table 4-6 Financial Cases for Solar Distributed Generation

CASES	CPI	CPI+1
2016	All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI.	All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI+1 percent.
2035	No incentives are available, except accelerated depreciation. 2035 cost assumptions. Utility rate escalates at CPI	No incentives are available, except accelerated depreciation, 2035 cost assumptions. Utility rate escalates at CPI+1 percent

Financially viable potential is defined as systems with paybacks of less than 20 years, or the life of the project, for both residential and commercial customers. In all cases, almost all of the systems identified in the technical screen were also financially viable, in that they had paybacks of less than 20 years.[14]

As mentioned earlier, additional criteria were used to screen the potential in PGE's service territory, including exclusion of multi-family dwellings and residential and commercial renters Table 4-7 shows the assumed percent of owner-occupied buildings by sector.[15]

Table 4-7 Assumed Owner-Occupied Portion of Buildings by Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC/ SEMI-PUBLIC
72%	48%	48%	100%

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[14] While it may seem surprising that nearly all the systems modelled are deemed financially viable, it is due to a few factors: (1) the technical potential estimate excluded lower quality systems with less than 75 percent TSRF, (2) incentives are often set to ensure systems can be financially viable, and (3) Black & Veatch is assuming cost reductions over time.

[15] The residential ownership data were provided by PGE, while the commercial ownership data were derived from EIA's 2003 Commercial Building Energy Consumption Survey (CBECS) for the Pacific region. The CBECS survey data represent a sampling of 580,000 buildings across California, Oregon, and Washington. No Oregon-specific data for commercial ownership were available.

For both 2016 and 2035 cases, under both utility rate increase scenarios, all systems analyzed demonstrated paybacks of fewer than 20 years across the scenarios. After applying the exclusions described above, the total remaining capacity represented is about 1,410 MWdc. Table 4-8 shows the breakdown between remaining residential and commercial customers classes for all scenarios.

Table 4-8 Potential Capacity Remaining After Financial Screens

CUSTOMER CLASS	ALL SCENARIOS (MWDC)
Residential	415
Commercial (including industrial and public / semi-public)	995
Total MWdc	1,410

4.2.5 Payback Distribution Discussion

For the various scenarios, however, the distributions of payback periods are different by customer type, year of analysis, and utility rate assumptions. The payback distribution for residential customers in 2016 and 2035 under CPI and CPI+1 percent are shown on Figure 4-7 and Figure 4-8. These graphs show the total MWdc of rooftop solar for each payback period (segmented by 0.1 years). The results show that while the cost of solar is assumed to decline significantly by 2035, the modest rise in utility rates in both cases is not sufficient to offset the lack of incentives. Therefore, the payback periods increase significantly in 2035. The residential paybacks appear to follow a log normal distribution with a wide range of payback periods due to site-specific solar resources (capacity factor) and system size (capital cost). In the 2035 CPI+1 percent scenario, the payback periods are improved compared to 2035 CPI scenarios, since the utility rate is higher by 2035.

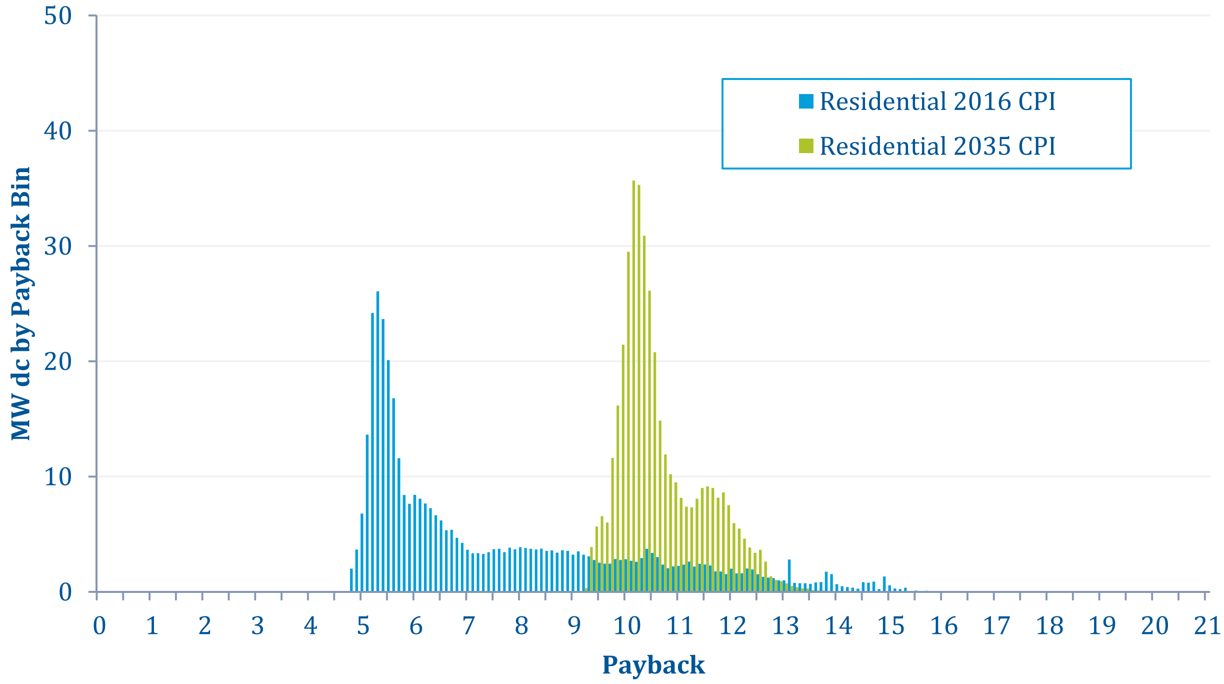

Figure 4-7 Residential Systems by Payback Periods (CPI Scenario)

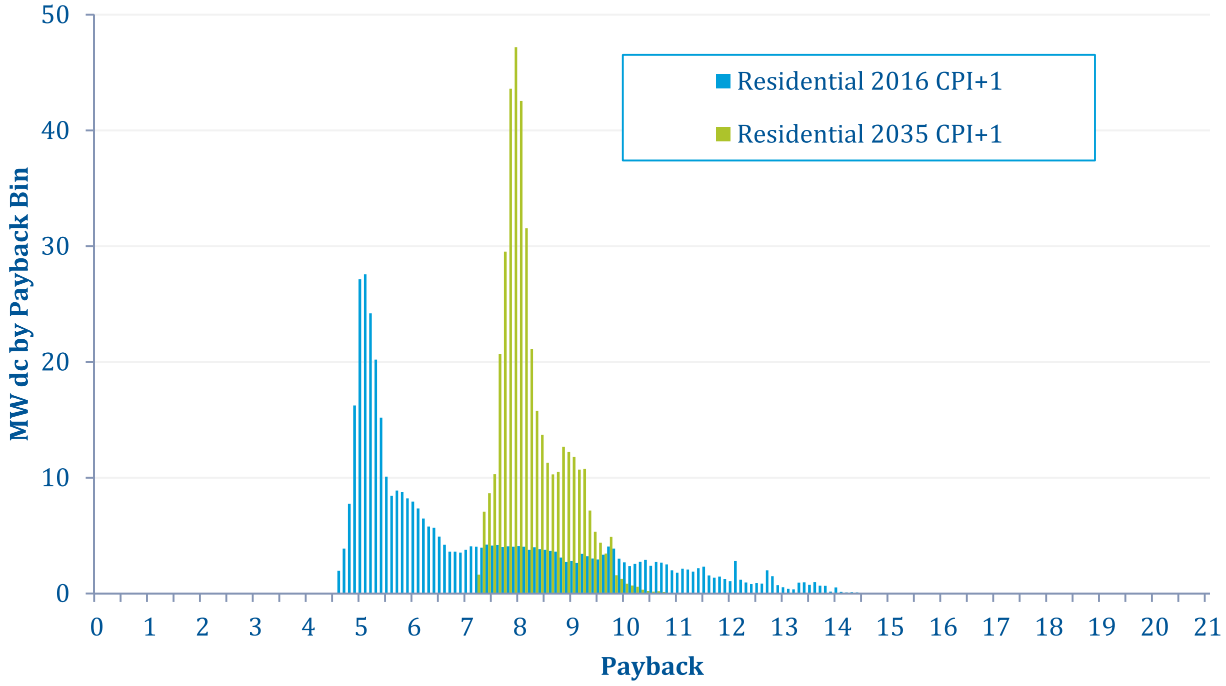

Figure 4-8 Residential Systems by Payback Periods (CPI+1 Scenario)

For commercial customers, the effect of the ETO incentive curve assumption in 2016 results in a bimodal distribution (i.e., two groups) of payback periods, as the ETO incentive does not reduce system costs uniformly across system sizes (refer to Figure 4-9 for the CPI scenario and Figure 4-10 for the CPI+1 scenario).

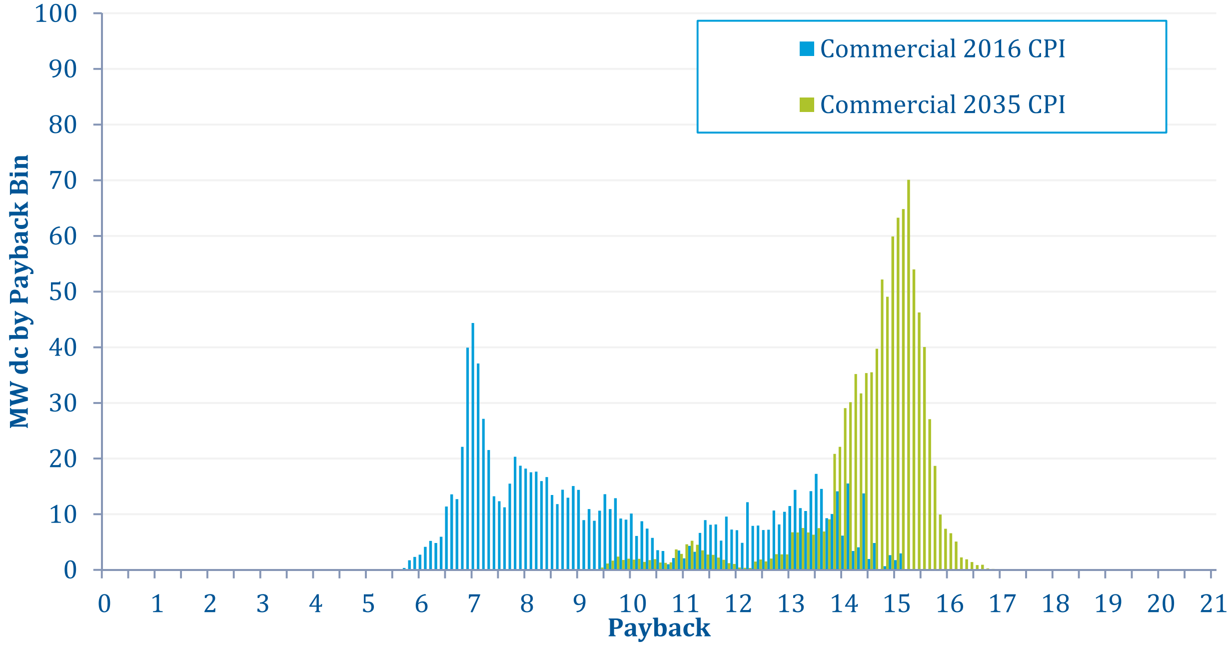

Figure 4-9 Commercial Systems by Payback Period (CPI Scenario)

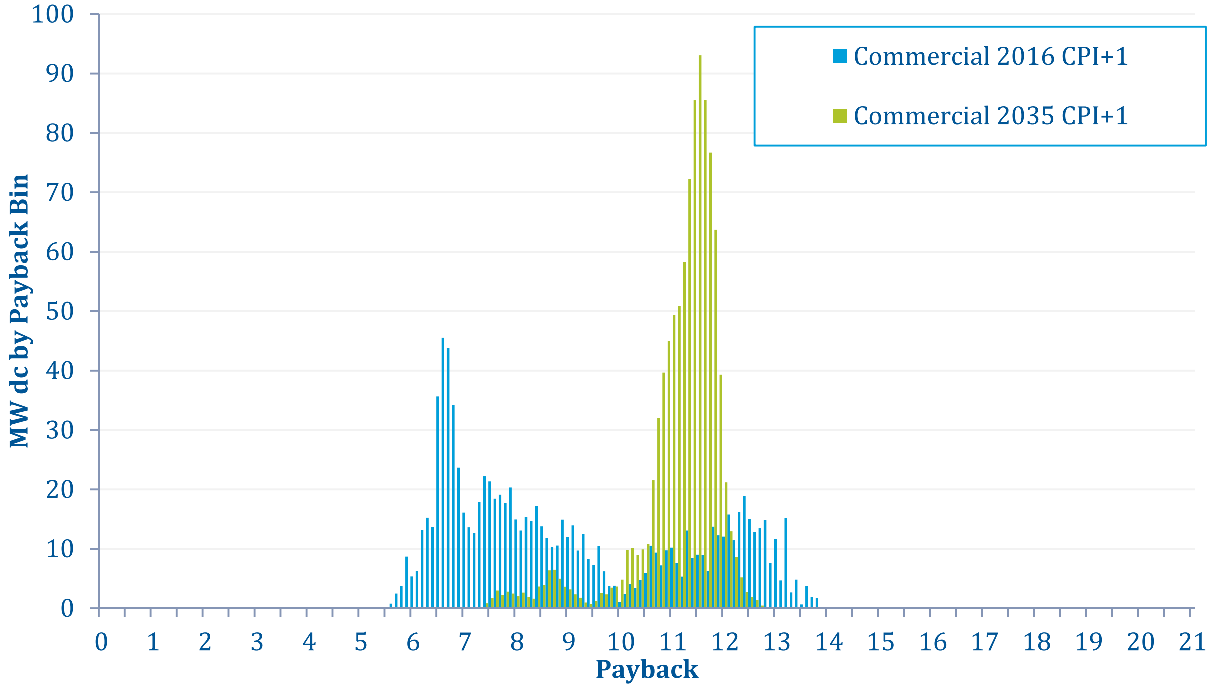

Figure 4-10 Commercial Systems by Payback Period (CPI+1 Scenario)

There is more complexity displayed in the distribution of commercial paybacks than in the residential sector distribution. This is due to the much wider range of system sizes available and the multiple rate schedules modeled. That said, the overriding trends in the commercial sector payback periods are similar to the residential sector. Payback periods are longer for systems in the 2035 case, and higher rate increase cases significantly lower paybacks. The commercial sector payback periods are more sensitive to rate increase assumptions because of the way bill savings are reduced by the effective tax rate in the cash flow calculation.

While the financial calculations show paybacks of less than 20 years for all systems, this does not necessarily translate to adoption by customers. There are other numerous factors that influence a customer's decision to adopt a technology that may not be directly tied to financials. In the next section, market penetration constraints are applied to the payback distribution to estimate achievable potential.

4.3 ACHIEVABLE SCREEN

In order to determine achievable potential within the study period, Black & Veatch used survey-based data to translate the previous payback distributions to maximum market potential and then forecasted the adoption of solar over the study period under two different approaches.

Black & Veatch took two approaches to capture the range of adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO constrained).

1. **Technology Adoption Limited:** The first approach is a bottom-up approach maximum achievable market potential and applying a technology adoption curve to simulate annual adoption going forward.
2. **ETO Funding Constrained**: For the top-down approach, Black & Veatch opted to test alternative scenarios where the payback, thus maximum market potential, over time is maintained at the same level as in 2016 by assuming thatETO incentives continue to be available during the study period.

The annual adoption scenarios tested are shown in Table 4-9.

Table 4-9 Scenarios for Annual DG Solar Adoption

	CPI	CPI+1
Technology Adoption Limited (Bottom-Up)	Market matures from incentives available in 2016 to no incentives available by 2035	Market matures from incentives available in 2016 to no incentives available by 2035
ETO Funding Limited* (Top-Down)	**With Tax Credits:** Federal (10% ITC) and state tax credits (residential only)** available throughout study period	**With Tax Credits:** Federal (10% ITC) and state tax credits (residential only)** available throughout study period
	No Tax Credits: Only ETO incentives are available	**No Tax Credits:** Only ETO incentives are available

* Total annual ETO funding is capped for residential ($3 million) and commercial ($2.6 million) customers, based on 2015 ETO incentives allocated to PGE's service territory.

** Oregon residential tax credit is stepped down by $0.20/W per year.

4.3.1 Maximum Market Potential

While the financial calculations show paybacks of less than 20 years for all systems, an individual's willingness to adopt the technology will depend on whether the payback period is attractive to the individual. Using the results of surveys of residential and commercial customers' preferences for adopting solar and distributed generation, NREL (residential) R.W. Beck (commercial), and Navigant (commercial) developed maximum market penetration curves that indicate the likelihood of market penetration given a certain amount of payback for that customer class. In other words, the survey data specifies what portion of a group of customers given a certain payback outlook, would actually adopt the technology--the shorter the payback period, the more likelihood of adoption. The penetration curve was then applied to the payback distribution for each of the financial cases to determine the total achievable potential. The two step process is described below:

1. **Maximum Market Penetration Curves:** Maximum market penetration curves represent the potential adoption of a technology based on an expected payback period (Figure 4-11). For example, for sites that can achieve a 5 year payback, the uptake by residential customers is about 64 percent, while commercial customers would be 22 percent. This is due, in large part, to commercial customers requiring much quicker paybacks on investments. These surveys account for the decision-making process across a broad demographic of customers.

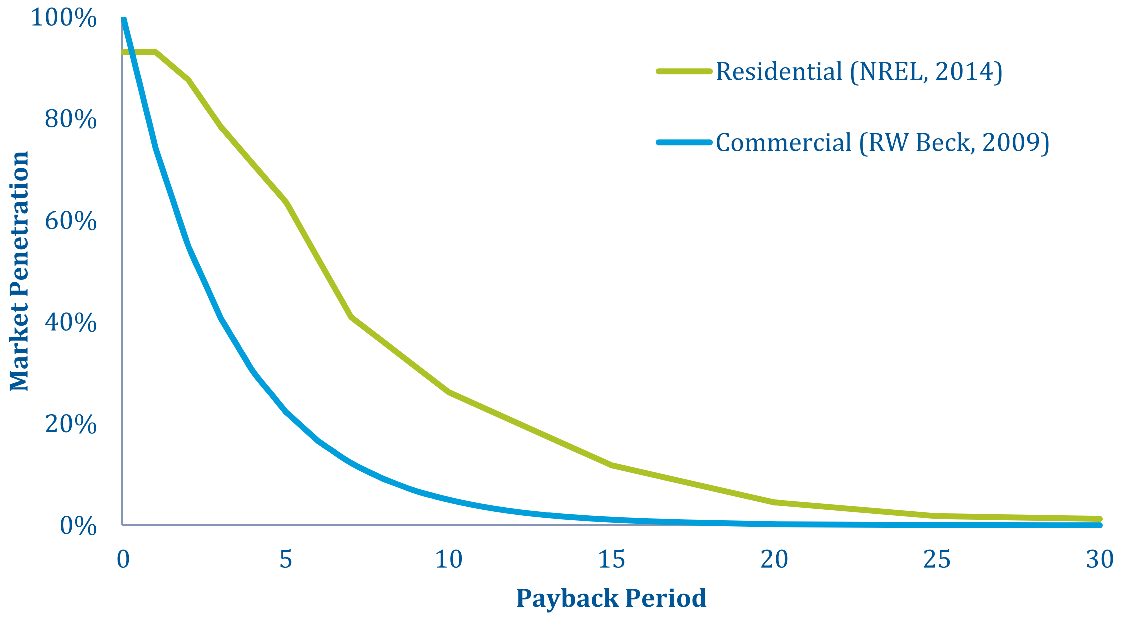

Figure 4-11 **Maximum Market Penetration Curve for DG Solar (source: NREL and R.W. Beck)**

2. **Resulting Maximum Market Potential:** By multiplying the payback distributions for each of the four financial cases and customer type (Figure 4-7 through Figure 4-10) and the max market penetration level for each payback period (Figure 4-11), it is then possible to derive the cumulative total maximum market potential for the customer class. Figure 4-12 and Figure 4-13 show the result for the CPI + 1 cases for residential and commercial customers. Note the application of the maximum market penetration curve greatly reduces the market potential when paybacks are 5 to 15 years, as they are in each of the cases in this study. It is also important to understand the powerful effect of the commercial market penetration curve on the commercial sector, as the potential is reduced from 995 MW of potential to just over 80 MW of maximum market potential in 2016 CPI+1 case. The maximum market potential is even lower in the other commercial customer cases. Furthermore, the maximum market potential in 2035 actually is lower than in 2016 because the net capital cost to customers increases in real dollars after expiration of incentives.

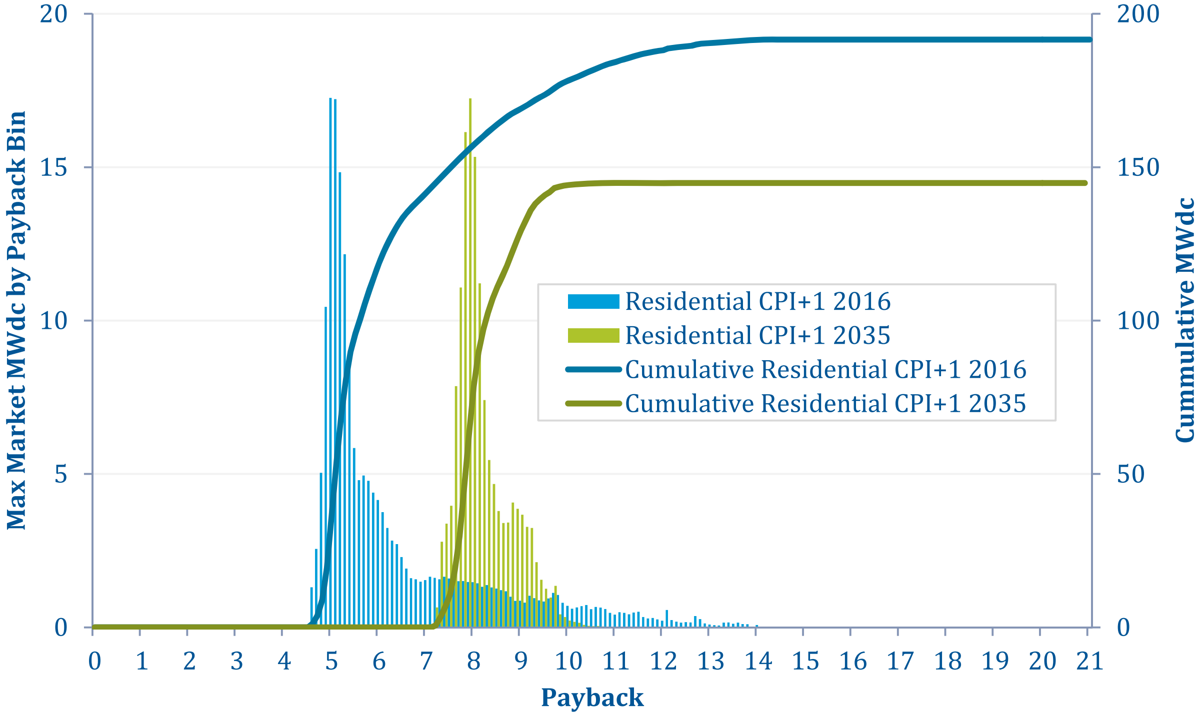

Figure 4-12 Maximum Market Potential Example (Residential CPI+1)

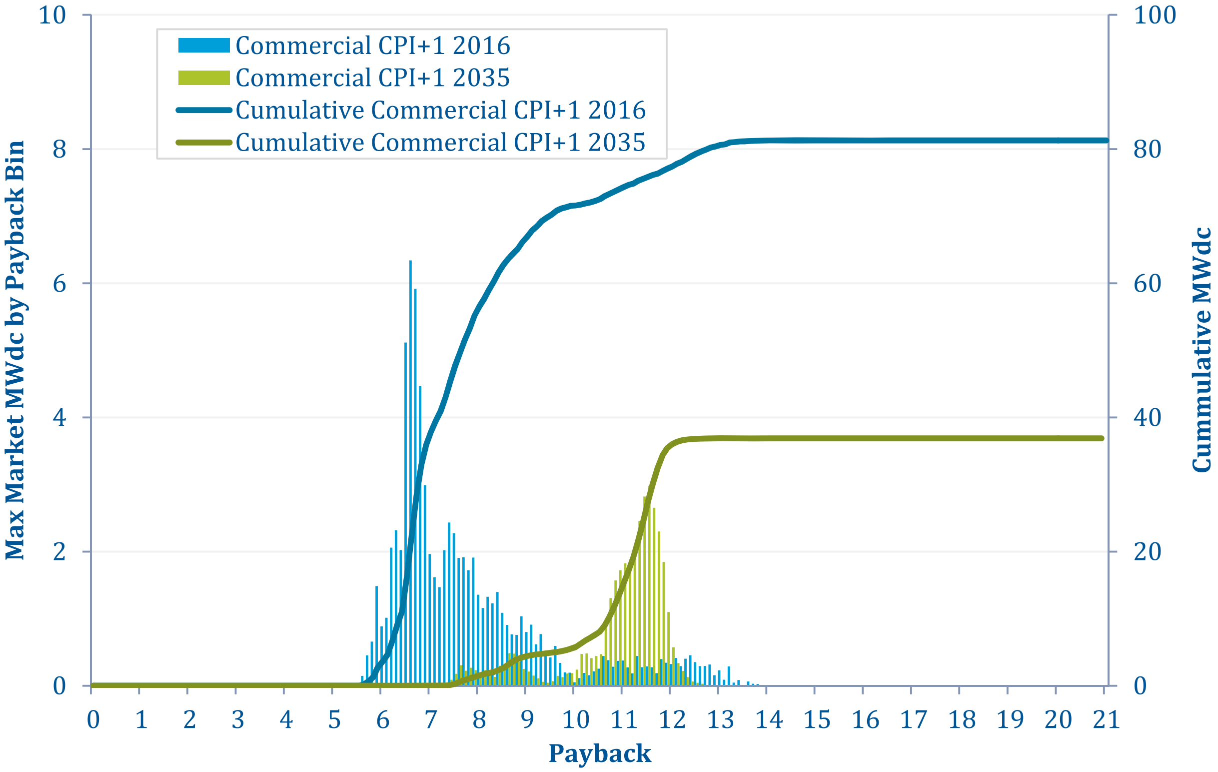

Figure 4-13 Maximum Market Potential Example (Commercial CPI+1)

The resulting cumulative maximum market potential for each of the cases tested is shown in Table 4-10. These represent the maximum market potential under each of the financial cases and include already installed systems in PGE service territory. The remaining market potential is also shown.

Table 4-10 Summary of Maximum Market Potential (MWdc)

	CPI		CPI+1	
	2016	2035	2016	2035
Residential	180	102	192	145
Commercial	70	14	81	37
Total	**250**	**116**	**273**	**182**
Remaining Potential (Less Current and 2015 Installations)	**202**	**68**	**225**	**134**

4.3.2 Annual Adoption Forecast

Taking the maximum market potential, Black & Veatch then developed estimates of annual adoption based on a range of adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch took two approaches to capture the range of forecasted adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO constrained), which are discussed in greater detail in the following sections.

4.3.2.1 Technology Adoption Limited

Once the maximum market potential under each of the four cases was determined, Black & Veatch implemented a standard analytical approach using a technology adoption curve approach to determine annual adoption over time. Black & Veatch relied on representative S-curve adoption curves to forecast adoption over time in this approach. Typically the adoption curve is applied to the maximum market potential to derive the annual adoption each year, but for the 2016 and 2035 cases tested, the maximum market penetration level is lower in 2035 cases than 2016 cases due to different cost and incentive assumptions, Therefore, the overall maximum market potential is assumed to decline linearly overtime between 2016 and 2035.

The steps below describe the process.

1. **Linear Decline of Maximum Market Potential**: Taking the 2016 and 2035 financial cases of maximum market potential as bookends, the maximum market potential was linearly interpolated across time to represent a decline in overall market potential. The decline in market size over time assumes that various state and federal incentives are being reduced over time as the market transitions to a self-sustaining, mature market. The lack of incentives by 2035 results in a smaller maximum market potential as PV paybacks are higher than in the 2016 cases when incentives are readily available. This implies that, given forecasted capital costs, the market potential by 2035 will continue to require incentives or alternative financing, at some level to support continued growth.

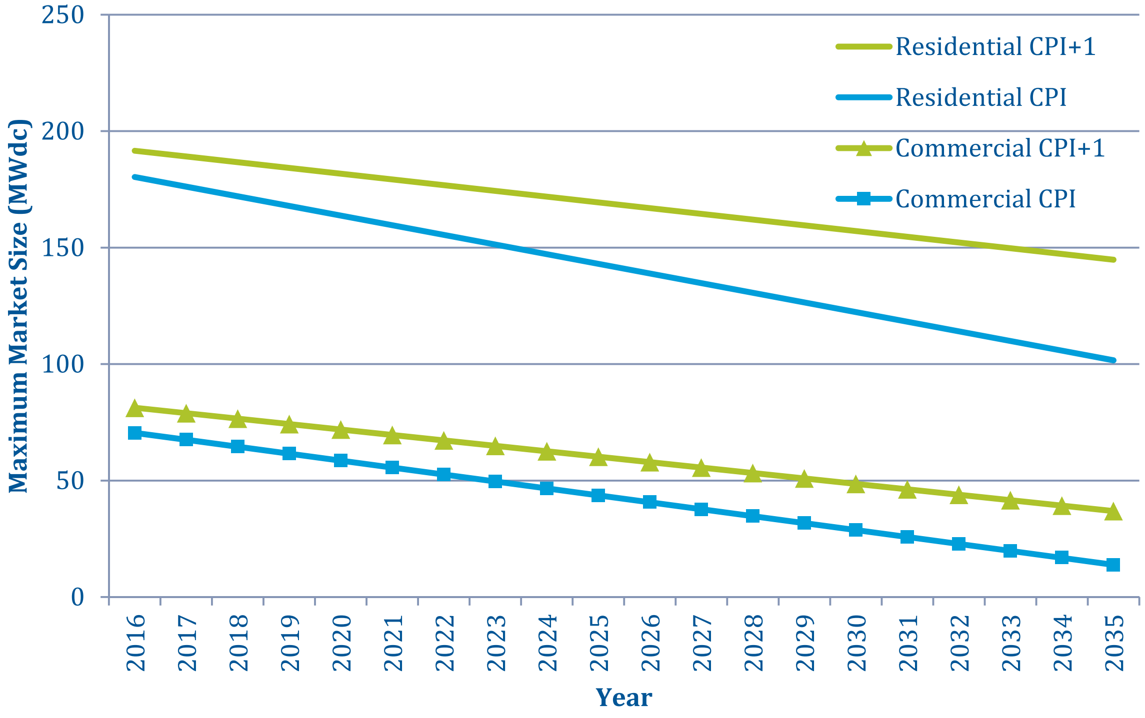

Figure 4-14 **Technology Adoption Limited Maximum Market Size Over Time**

2. **Adoption Curve:** Once the maximum market potential is established, the annual uptake of the technology each year is then determined using a technology adoption curve approach. The rate of PV adoption (S-Curve) is calculated using the bass-diffusion model where time (T), the "coefficient of innovation" characterizing early adopters of a technology (p), and the "coefficient of imitation" characterizing late adopters of a technology (q) define the rate of adoption. Because paybacks of up to 20 years are included, the maximum market potential was further divided into those with paybacks equal to or less than 10 years and those greater than 10 years, as these two different segments would have different adoption rates.[16] The bass-diffusion model p and q values came from NREL's SolarDS work. NREL uses a p value of 0.0015, and a q value that varies with the financial attractiveness. For paybacks of 3 to 10 years, q = 0.4, and for payback greater than 10 years, q = 0.3. Because the solar market is relatively nascent and dynamic, there is not a strong empirical rationale for these exact values, but the values are based on NREL's literature review in 2009, which indicated these as suitable values for technologies similar to distributed PV.[17] Figure 4-15 shows the two adoption curves. Notably, it takes about 22 years to reach 95 percent market adoption for paybacks less than 10 years, and 28 years for paybacks greater than 10 years.

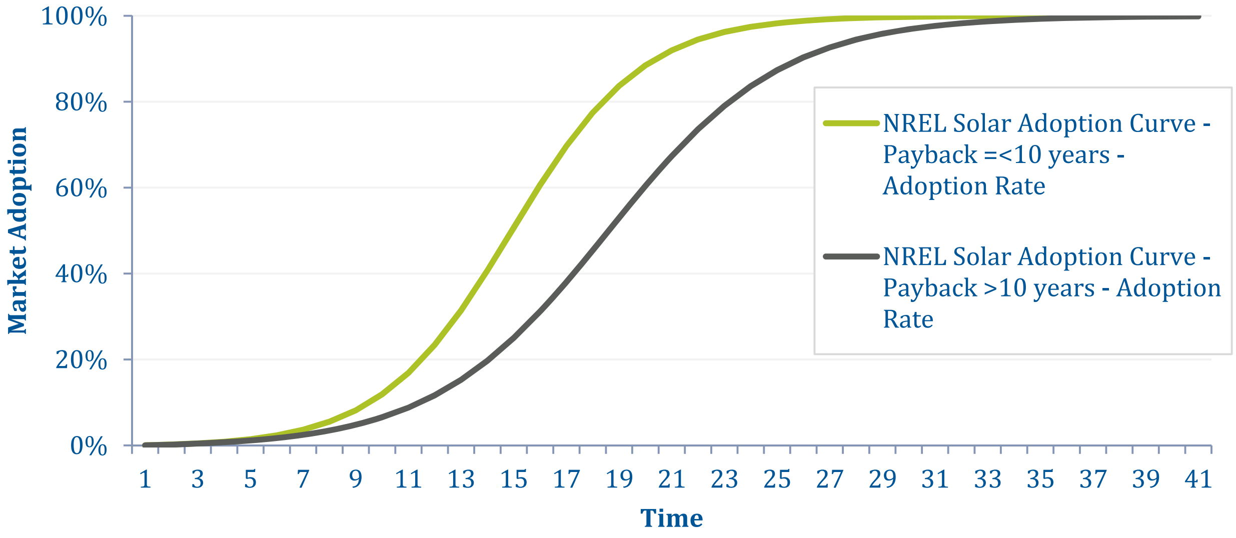

Figure 4-15 Assumed Solar Adoption S-Curves for Two Payback Ranges (adapted from NREL)

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[16] "Advanced Modeling of Renewable Energy Market Dynamics," May 2006, NREL. http://www.nrel.gov/docs/fy07osti/41896.pdf.

[17] Mahajan, Vijay; Muller, Eitan and Bass, Frank (1995). "Diffusion of new products: Empirical generalizations and managerial uses." Marketing Science 14 (3): G79-G88. doi:10.1287/mksc.14.3.G79.

3. **Current Penetration Level:** To determine the starting point on the adoption curve, Black & Veatch included the total installations in PGE's service territory through 2015 and divided this number by the maximum market potential found for 2016. The initial penetration level includes currently installed net metered and solar feed-in-tariff systems within PGE's service territory, less large ground-mount systems, and additional estimated installations in 2015 based on ETO's planned solar incentives in PGE's service territory. The total MWdc of installed capacity used for determining initial penetration year for residential and commercial customers respectively, were 27.8 and 20.1 MW, respectively. These correspond to the 9th and 11th year along the adoption curves for residential and commercial customers. This matches well with the fact that the ETO has been promoting solar through incentive programs for about 10 years. Refer to Table 4-11.

Table 4-11 Current 2014 and Estimated 2015 Installed Base of DG Solar in PGE Service Territory

CUSTOMER CLASS	2014 INSTALLED CAPACITY (MWDC)*	ESTIMATED ETO FUNDED INSTALLATIONS IN 2015 (MWDC)**	CUMULATIVE INSTALLATIONS THROUGH 2015 (MWDC)	ESTIMATED ADOPTION YEAR
Residential	23.5	4.3	27.8	9
Commercial	17.0	3.0	20.1	11

* Total installed capacity includes Net Metered and Solar Payment Option projects (level 1 interconnection only) in PGE service territory.

**Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

4. **Annual Adoption:** Once a starting point for adoption year was established, Black & Veatch was then able to model the annual adoption of solar PV for the 20 year study period by multiplying the level of adoption for a given year (Figure 4-15) by the corresponding maximum market potential for that year (Figure 4-14) . The resulting annual adoption levels over time for the two utility rate scenarios are shown on Figure 4-16 and Table 4-12. Since solar adoption in PGE's territory was already 9 to11 years along the adoption curves, the adoption rate in the next decade will see an acceleration in adoption until the adoption rate slows down and cumulative market adoption, including the installed base, reaches the maximum market potential, consistent with the adoption curves in Figure 4-15.

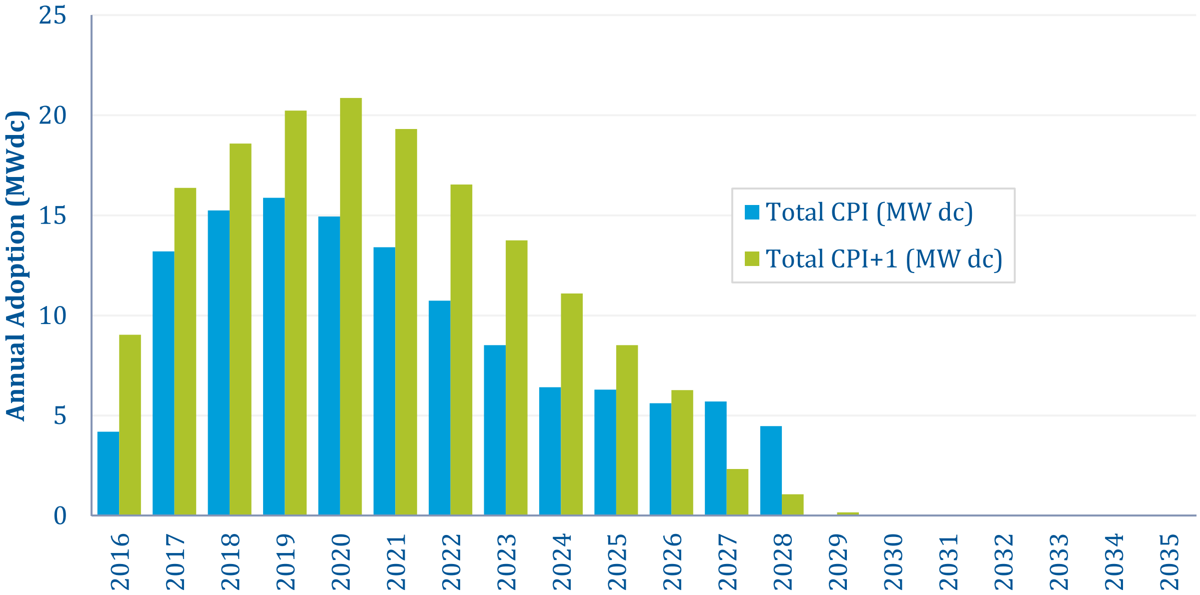


Figure 4-16 Technology Adoption Limited Annual Solar Distributed Generation Adoption (2016-2035)

The total cumulative solar installations between 2016 and 2035 equal 124.2 MWdc (CPI) and 164.2 MWdc (CPI+1).

Table 4-12 Technology Adoption Limited Annual Solar Distributed Generation Adoption (MWdc)

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CPI	4.2	13.2	15.2	15.9	14.9	13.4	10.7	8.5	6.4	6.3
CPI+1	9.0	16.4	18.6	20.2	20.9	19.3	16.5	13.8	11.1	8.5
YEAR	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
CPI	5.6	5.7	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPI+1	6.3	2.3	1.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0

While these scenarios reflect a bottom-up approach to capturing market dynamics of technology adoption over time, they do rely on the assumption that sufficient incentives are available to achieve the maximum market potential as forecasted in the intermediate years between 2016 and 2035. These results also reflect a declining market potential because of the inherent assumption that no incentives are available by 2035. By about 2028, the maximum market potential is reached and no additional solar PV is adopted thereafter. In other words, all the customers who would install PV systems have already installed those systems by about 2028-29. Refer to Figure 4-17.

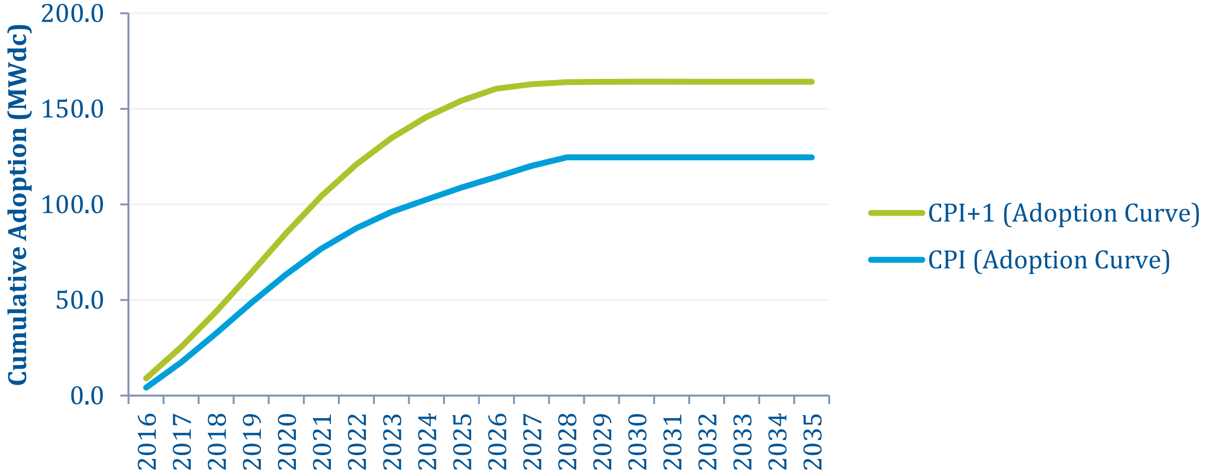


Figure 4-17 Technology Adoption Limited Cumulative DG Solar Adoption

In the next section, the impact of incentive funding on adoption is examined.

4.3.2.2 ETO Funding Achievable Potential

In the previous analysis, it was assumed that incentives would not be available by 2035, which resulted in higher paybacks and declining maximum market potential over time. For this analysis, it is assumed that the payback levels, thus maximum market potential established in 2016 would be maintained by adjusting the level of ETO incentives each year going forward. Thus, the maximum market potential remains the same over the study period at 250 MW (CPI) and 273 MW (CPI+1) for the entire study period (see Table 4-10). The remaining potential after netting existing and 2015 installations is also shown.

Table 4-13 Maximum Market Potential for DG Solar Under 2016 Case

	CPI (2016)	CPI+1 (2016)
Residential	180	192
Commercial	70	81
Total	**250**	**273**
Remaining Potential (Less Current and 2015 Installations)	**202**	**225**

The assumed objective for these scenarios is that the ETO would provide enough incentives ($/W) to maintain similar payback levels as modeled for the 2016 cases for residential and commercial customers. The ETO $ per W incentive levels are adjusted under different tax incentives conditions and rate increases (CPI and CPI+1 percent). The one limitation is that the absolute annual ETO funding is capped at the announced 2015 levels-- residential ($3 million) and commercial ($2.6

million)--thus limiting the annual MW of projects that the annual budget can support. Black & Veatch assumed this cap increases with the corresponding inflation assumption.

Figure 4-18 and Figure 4-19 show the annual adoption under each of the scenarios. For the cases with tax incentives, greater adoption is seen in the early years because residential customers are assumed to continue to receive the Oregon tax credit, stepped down by $0.20 per W per year, so fewer ETO incentives are needed. Lower ETO incentives mean more capacity can be funded given the fixed amount of funding available. Furthermore, since the maximum market potential for commercial customers is fairly low, the commercial market is saturated by the middle of the study period. Additional breakdown of adoption between commercial and residential customers is provided in 5.3Appendix D.

The highest total cumulative adoption cases by the end of the study period are the two cases that assume a continuation of Oregon tax credits and availability of a 10 percent ITC for the entire study period (Figure 4-20). The detailed annual adoption levels are provided in 5.3Appendix D. In all cases, some ETO incentives are needed throughout the entire study period to maintain the original payback level.

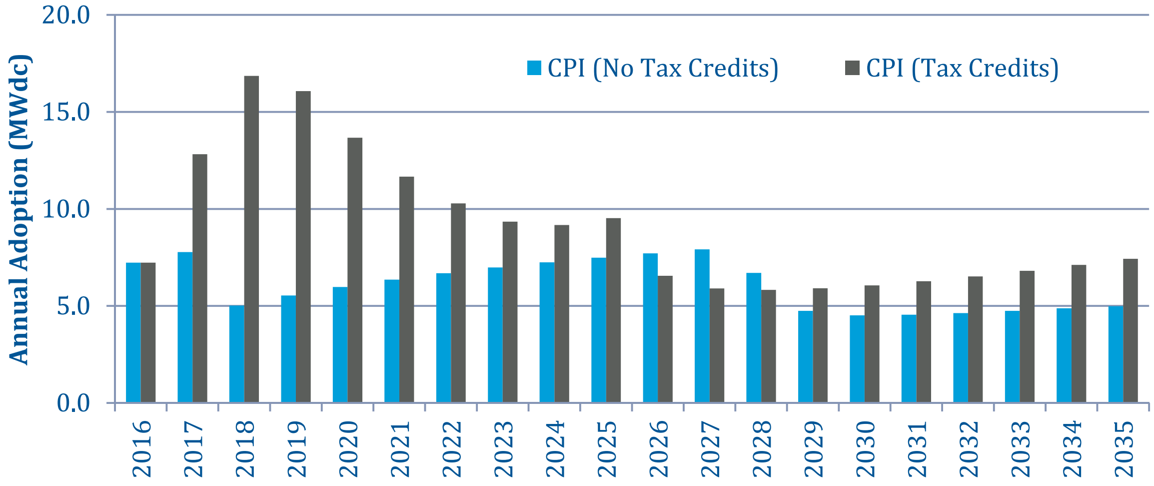


Figure 4-18 ETO Funding Limited Total Annual DG Solar Adoption (CPI)

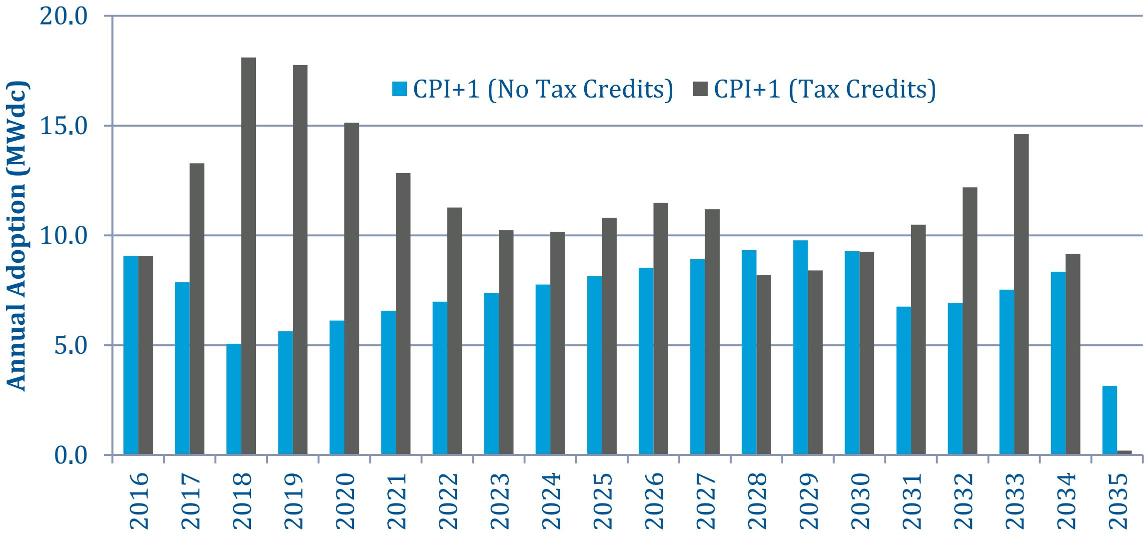


Figure 4-19 ETO Funding Limited Total Annual DG Solar Adoption (CPI+1)

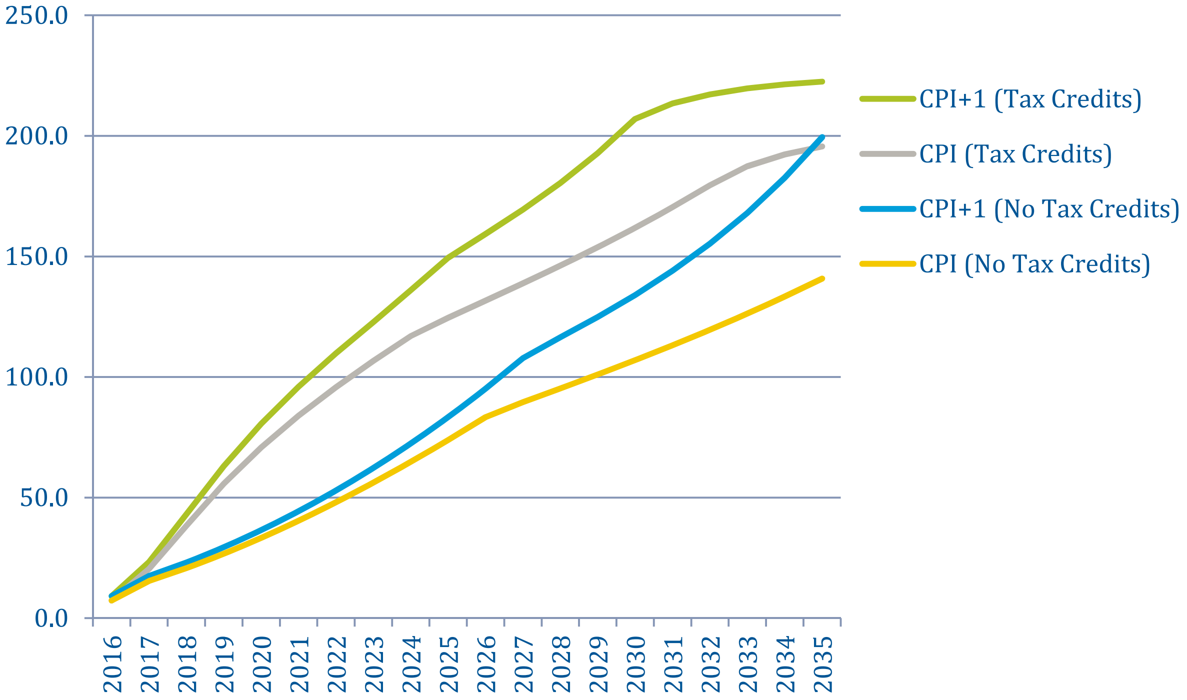


Figure 4-20 ETO Funding Limited Cumulative DG Solar Adoption (2016-2035)

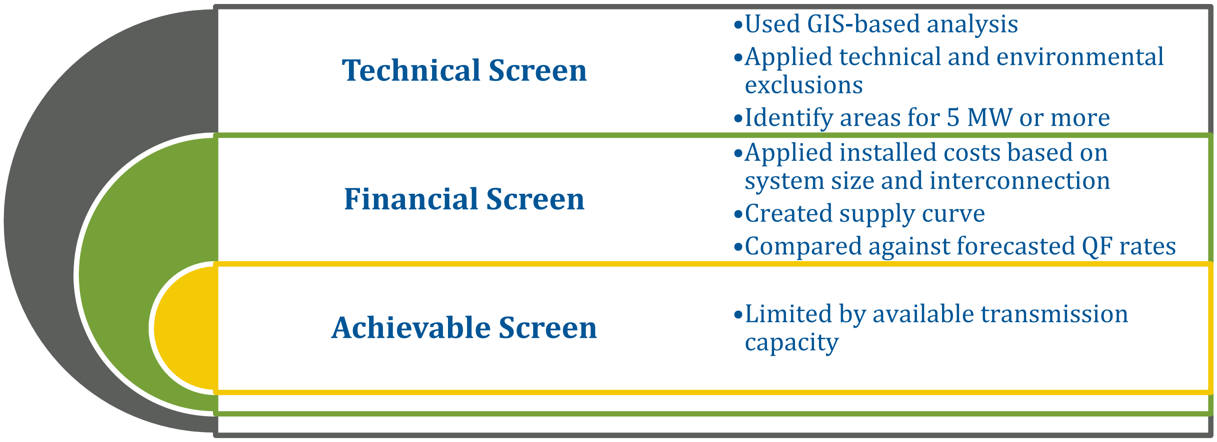
The total cumulative solar installation between 2016 and 2035 without tax credits equals 140.8MWdc (CPI) and 199.5MWdc (CPI+1), and with tax credits equals 195.6 MWdc (CPI) and 222.5 MWdc (CPI+1).

Table 4-14 ETO Funding Limited Annual Solar Distributed Generation Adoption (MWdc)

	CPI (ETO FUNDING -NO TAX CREDITS)			CPI+1 (ETO FUNDING - NO TAX CREDITS)			CPI (ETO FUNDING – WITH TAX CREDITS)			CPI+1 (ETO FUDNING – WITH TAX CREDITS)		
	RES	COM	TOTAL	RES	COM	TOTAL	RES	COM	TOTAL	RES	COM	TOTAL
2016	2.4	4.9	7.3	4.2	5.0	9.2	2.4	4.9	7.3	4.2	5.0	9.2
2017	5.2	2.9	8.1	5.4	3.0	8.3	9.9	3.2	13.1	10.4	3.7	14.1
2018	2.0	3.3	5.3	2.1	3.4	5.5	13.8	4.1	17.9	15.5	4.3	19.8
2019	2.3	3.7	6.0	2.5	3.9	6.3	12.8	4.6	17.4	15.1	4.9	20.0
2020	2.6	3.9	6.6	2.9	4.2	7.1	10.1	5.0	15.1	12.2	5.4	17.5
2021	2.9	4.2	7.1	3.3	4.6	7.8	7.8	5.3	13.1	9.5	5.9	15.3
2022	3.2	4.4	7.6	3.7	4.9	8.6	6.2	5.6	11.8	7.5	6.3	13.9
2023	3.5	4.6	8.1	4.1	5.2	9.3	5.1	5.9	10.9	6.2	6.8	13.0
2024	3.8	4.8	8.6	4.6	5.5	10.1	4.9	5.4	10.3	6.1	7.2	13.3
2025	4.1	5.0	9.1	5.1	5.8	10.9	5.3	2.3	7.6	6.9	6.5	13.4
2026	4.4	5.1	9.5	5.7	6.1	11.8	5.8	1.4	7.1	7.8	2.0	9.9
2027	4.7	1.5	6.2	6.3	6.4	12.7	6.2	0.9	7.1	9.0	1.1	10.1
2028	5.0	0.7	5.7	7.0	1.5	8.6	6.7	0.6	7.3	10.3	0.7	11.0
2029	5.3	0.4	5.8	7.8	0.6	8.4	7.2	0.4	7.7	11.9	0.5	12.4
2030	5.6	0.3	5.9	8.8	0.3	9.1	7.8	0.3	8.1	13.9	0.3	14.2
2031	6.0	0.2	6.2	9.8	0.2	10.1	8.3	0.2	8.5	6.2	0.2	6.4
2032	6.3	0.1	6.4	11.1	0.1	11.3	8.9	0.1	9.1	3.6	0.1	3.7
2033	6.7	0.1	6.7	12.6	0.1	12.7	7.8	0.1	7.9	2.4	0.1	2.5
2034	7.0	0.1	7.1	14.5	0.1	14.6	4.8	0.1	4.9	1.6	0.1	1.7
2035	7.4	0.0	7.4	16.9	0.0	16.9	3.3	0.0	3.3	1.1	0.0	1.1
Total	**90.5**	**50.3**	**140.8**	**138.5**	**61.0**	**199.5**	**145.4**	**50.3**	**195.6**	**161.5**	**61.0**	**222.5**

5.0 Utility-Scale Solar PV Potential Assessment

Applying lessons learned from the California Renewable Energy Transmission Initiative (RETI) and Western Renewable Energy Zones (WREZ) planning work, Black & Veatch estimated utility-scale solar PV potential across Oregon using the screens described below. Since utility-scale projects are developed at a much larger scale and have greater environmental sensitivities than distributed generation, a different approach was taken to evaluate the potential for Oregon.



Technical Screen

- Used GIS-based analysis
- Applied technical and environmental exclusions
- Identify areas for 5 MW or more

Financial Screen

- Applied installed costs based on system size and interconnection
- Created supply curve
- Compared against forecasted QF rates

Achievable Screen

- Limited by available transmission capacity

The utility-scale solar potential assessment focused on areas across Oregon for projects ranging from 5 to 250 MWac. Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites, assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect. This assumes no new transmission is built in Oregon.

5.1 THE SECTIONS BELOW FURTHER DESCRIBE THIS ANALYSIS AND THE RESULTS. TECHNICAL SCREEN

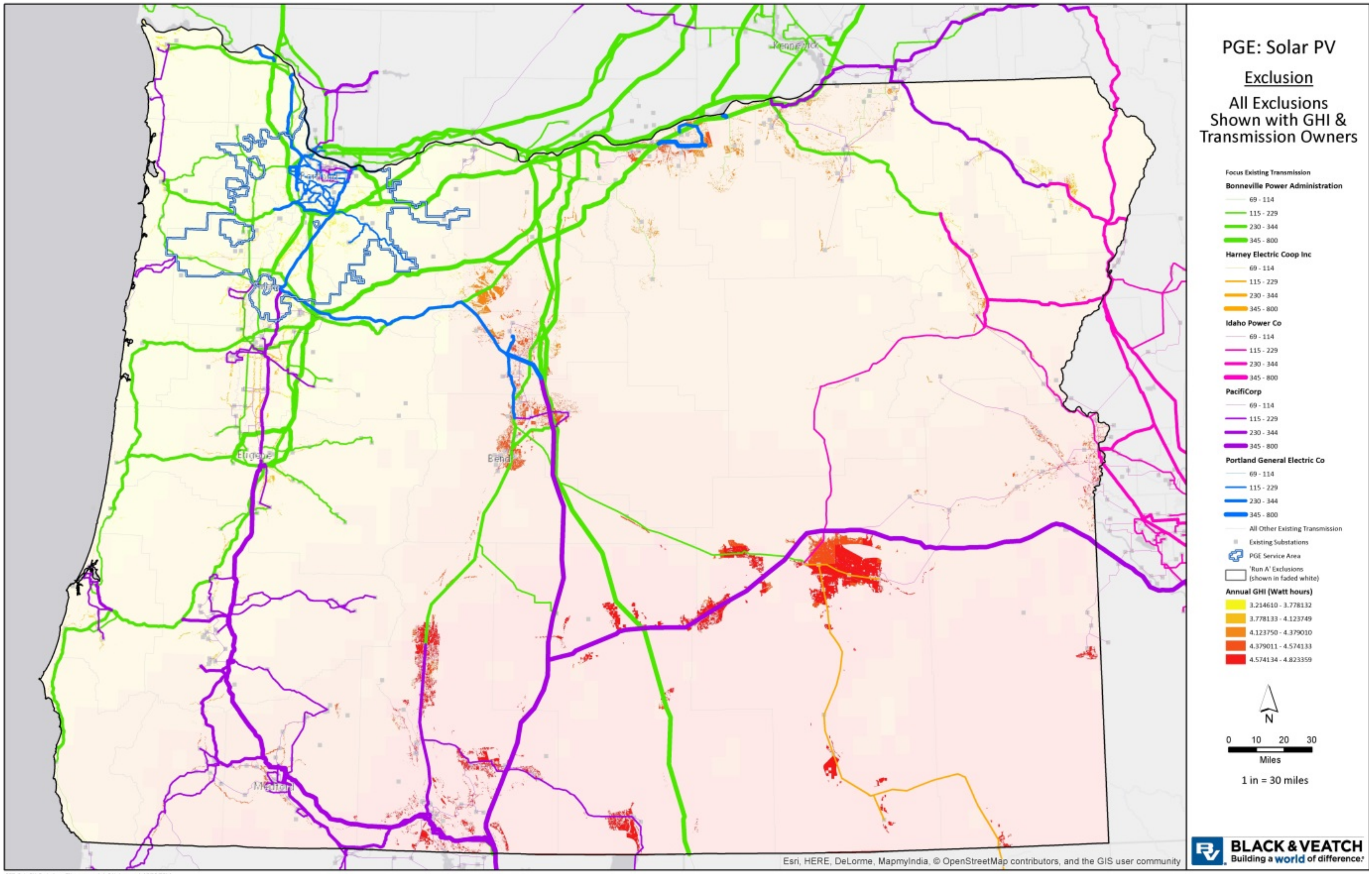
Using publicly available geographic information system (GIS) layers, Black & Veatch excluded areas that would pose challenges for solar PV development on the basis of land use and environmental constraints (e.g., environmentally sensitive lands, sage grouse habitat, public ownership and parklands, waterways, forested land, cropland, and wetlands). Also excluded were areas too far from current transmission infrastructure and land with significant slope. A summary of the excluded areas is provided in Table 5-1. Additional maps showing each of these exclusion areas can be found in Appendix E.

The exclusions have simply been applied for the purposes of estimating technical potential. It is important to emphasize that the purpose of these exclusions is for conceptual planning and not to recommend specific project siting and land use decisions. Development may be possible within some of the lands that have been excluded. Conversely, candidate lands shown as "open" for development should not necessarily be assumed to be appropriate for siting plants either. Any project will still need to proceed through all local, state, and federal permitting processes.

Table 5-1 Area Exclusions for Utility-Scale Solar PV Development

MAP LAYERS	EXCLUSIONS	DATA SOURCE
WECC Environmental Data Task Force (EDTF)	Categories 3 (high risk) and 4 (precluded by law)	WECC Geospatial Data Viewer
Sage Grouse	Sage grouse habitat	http://184.169.179.203/flexviewers/WECC3/index.html
Public Ownership and Parkland	Bureau of Land Management, Department of Defense, Forest Service and Fish & Wildlife land	https://nrimp.dfw.state.or.us/DataClearinghouse/default.aspx?p=202&XMLname=944.xml
Land Use	Water, forests (all types), cultivated crops, wetlands (all types), developed (low, medium, high intensity), perennial snow/ice	ESRI detailed parks dataset 2013
Transmission System	Greater than 5 miles from transmission lines	http://www.oregon.gov/odf/pages/gis/gisdata.aspx "Public Ownership"
Topography	Slope greater than 5 percent	National Land Cover Database 2011

In order to accommodate a minimum of 3.6 MWac, the GIS analysis then identified contiguous areas remaining that were greater than 25 acres. Each site area was then divided by a factor of 3.6 acres per MWac (equivalent to 5 acres per MWdc) to determine the technical potential per site. The dark orange and red colors on Figure 5-1 show the identified utility-scale potential sites.



PGE_SolarPV_Exclusions_TXowners.mxd | C.Holmgren | 12/15/2014

Figure 5-1 Identified Utility-Scale Solar PV Technical Potential

The maximum system size for a particular site was then constrained based on the voltage of the transmission line or substation that the site would need to interconnect with. In addition to limitations related to line or substation capacity, Black & Veatch made several assumptions regarding interconnection:

- No new transmission is built.
- Each contiguous area identified in the technical screen is considered a "site" and has only one solar PV project associated with the "site."
- The solar PV system size per site is capped at what the closest transmission line or substation voltage can accept. The maximum assumed system size in MWac for the respective transmission/substation voltages are shown in Table 5-2.

Table 5-2 Assumed Maximum Utility-Scale Project Size by Interconnection Voltage

TRANSMISSION/SUBSTATION VOLTAGE	MAXIMUM PROJECT SIZE (MWAC)
<100 kV	50
115 kV	100
230 kV	250
500 kV	250

Based on this screen, Black & Veatch identified approximately 3,500 potential sites in Oregon (Table 5-3). The total technical potential across Oregon is estimated to be over 56 gigawatts (GW), assuming a capacity density of 3.6 acres per MWac.

Table 5-3 Identified Utility-Scale Solar PV Technical Potential (MWac)

MW BIN	NUMBER OF PROJECTS PER BIN	TOTAL TECHNICAL POTENTIAL (MWAC)
<20	2,834	22,104
20-50	514	17,226
50-100	99	8,005
100-250	44	8,812
Total	**3,491**	**56,147**

5.2 FINANCIAL SCREEN

Black & Veatch then developed LCOE supply curves for each year in the study period, both with and without tax credit incentives. Using the technical screen results, the SolarAnywhere solar resource data, and the previously projected costs of utility-scale solar and transmission interconnection, Black & Veatch calculated the LCOE of individual sites identified previously. As with the distributed generation potential, Black & Veatch utilized SAM to perform the energy production analysis for the utility-scale systems. The LCOE of each project site was calculated using Black & Veatch's proprietary tools and supply curves were developed for each financial case. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability.

5.2.1 Cost Assumptions

The capital cost assumptions for each site are based on system size, gen-tie cost, and substation cost. The solar PV plant costs were forecasted to decline over time using the cost curves developed in Section 3.0. Gen-tie costs from Table 3-3 were applied based on the distance to the nearest substation or transmission line, which was calculated using GIS analysis. All projects were assumed to require a new substation or upgrades to an existing substation at costs for each respective voltage level summarized in Table 3-3.

For ongoing costs, both O&M, property taxes, wheeling charges and real power losses were included, where applicable. The O&M costs include typical costs associated with an O&M contract as well as inverter replacement fund, insurance, and land leases. The fixed O&M costs range from $32 to $36 per kWac-year (in 2014$), depending on the size of the system. Annual property taxes was assumed to be 0.5% of the installed cost of the system, though actual property taxes for projects will differ by county and alternative payment mechanisms may be negotiated with local government. Additional wheeling charges/transmission tariffs for sites connecting to transmission lines not owned by PGE were also applied to deliver the energy to PGE's service territory. Energy losses (real power losses) to wheel power were also included. Wheeling and real power losses are shown in Table 5-4. In some cases, wheeling and real power losses through multiple transmission providers needed to be applied to reach PGE territory.

Table 5-4 Transmission Tariffs by Owner (2014)

TRANSMISSION OWNER	TOTAL TRANSMISSION TARIFF/WHEELING CHARGE ($/KWAC-YR)	REAL POWER LOSSES
Bonneville Power Administration	$20.8	1.9%
PacifiCorp	$31.6	4.6%
Idaho Power	$22.7	3.6%
Harney Elec. Cooperative (see notes)	$13.2	0%

Sources:

Transmission tariff includes Point-to-Point Annual Firm Transmission,

BPA – 2014-2015 Tariffs for Generators http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Rate%20Schedule%20Summary_10-01-13.pdf and

http://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf

PacifiCorp – http://www.oatioasis.com/PPW/PPWdocs/Rate_Table_20140601.pdf and

http://www.oasis.oati.com/PPW/PPWdocs/Rate_Update_FAQ_20140601.pdfIdaho Power

http://www.oatioasis.com/IPCO/IPCOdocs/IPC_OATT_Issued_2015-01-13.pdf and

http://www.oatioasis.com/IPCO/IPCOdocs/IPCO_Current_Transmission_Rates_08-28-14.pdf

Harney Elec. Cooperative does not have published wheeling costs for generation on its system and has indicated that rates would be established as needed. Therefore, Black & Veatch used another Oregon cooperative, Central Electric Coop, as a proxy for wheeling cost. –http://www.cec.coop/wp-content/uploads/sch_w.pdf. Neither cooperative published losses, so assumed 0% losses.

5.2.2 Production and Financial Modeling

To estimate the energy production of each facility, Black & Veatch developed system assumptions that are representative of typical system parameters or losses seen in the industry for inputs into SAM. These assumptions are summarized in Appendix E, Table E-2. Energy production for each individual site was modeled using SAM and solar resource data from SolarAnywhere.

Financial assumptions used for modeling utility-scale solar PV assumed a typical independent power producer (IPP) ownership structure. These are summarized in Table 5-5.

Table 5-5 Utility-Scale Financial Assumptions

INPUTS	ASSUMPTION
Debt/Equity Assumption	All Equity
Equity Return Requirement (%)	6.5
Analysis Period (years)	20
Inflation Rate (%/year)	2
O&M Escalation (%/year)	1
Discount Rate (%)	6.5
Federal Income Tax Rate (%)	35
State Income Tax Rate (%)	7.6
Sales Tax	Exempt

5.2.3 LCOE Analysis Results

Rather than performing payback analysis, Black & Veatch chose to calculate LCOE for the identified utility-scale systems. The LCOE metric is more applicable to utility-scale systems because the energy is sold at the wholesale level and can be compared to a utility's cost of energy.

Black & Veatch calculated two cost scenarios: with and without ITC, with the exception that the ITC of 30 percent is available in 2016 in both cost scenarios. For the ITC scenario, it was assumed that the ITC drops to 10 percent after 2016. Cost curves were developed for all years from 2016 to 2035. Sample years of resulting supply curves for the ITC case are shown on Figures 5-2 and 5-3.

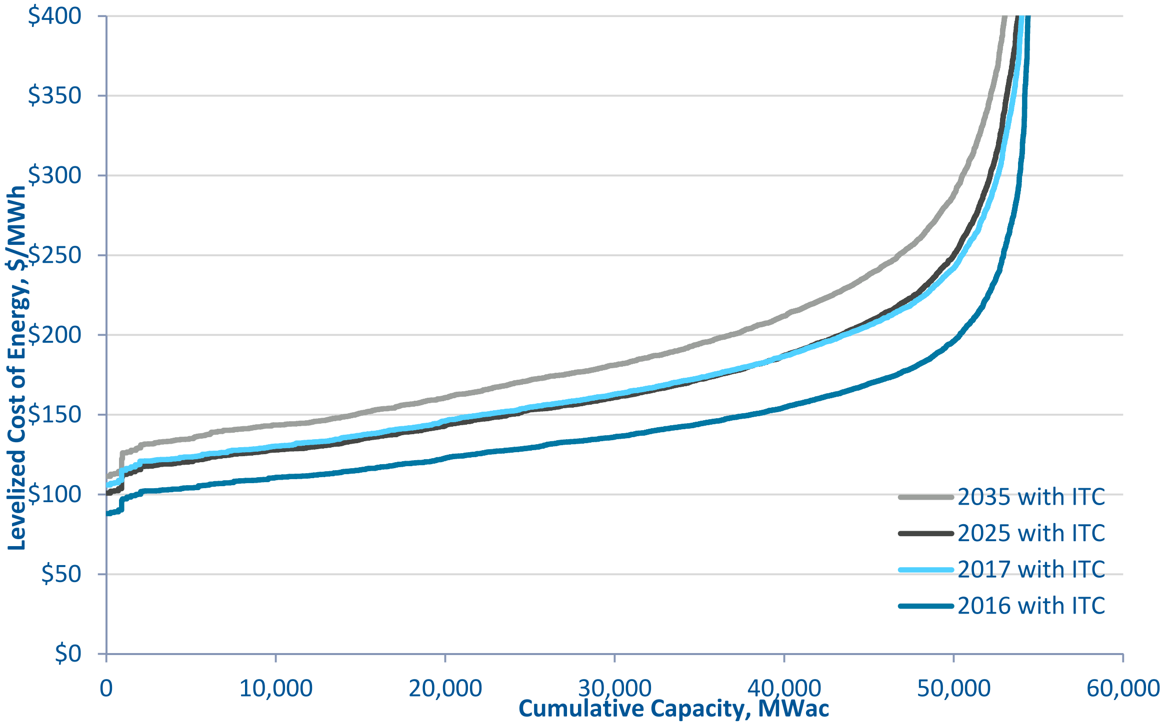


Figure 5-2 **Utility Solar Supply Curve With ITC (10% after 2016)**

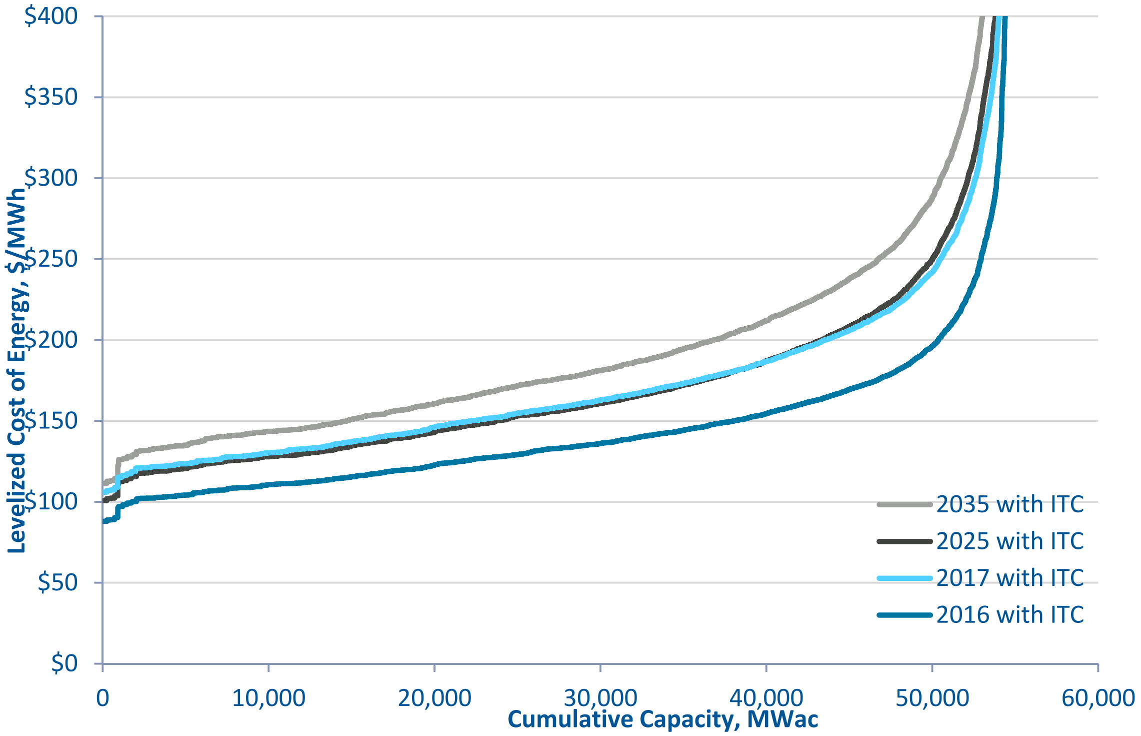


Figure 5-3 **Utility Solar Supply Curve Without ITC**

5.2.4 Avoided Cost Screen

Utility-scale solar PV will offset power purchases, power generation, or new power plant construction that PGE might otherwise make. Black & Veatch calculated the levelized cost of PGE's long-term QF tariff for variable solar to compare against the LCOEs previously calculated. The QF values used are shown in Table 5-6.

Comparing solar LCOE to QF rates is a simplified screening approach. Other approaches in examining solar PV financials may be considered in future studies.

Table 5-6 PGE QF Tariffs ($/MWh) for Variable Solar (Nominal)

YEAR	SOLAR PRODUCTION WEIGHTED AVERAGE PRICE	LEVELIZED COST (20 YEARS)	YEAR	SOLAR PRODUCTION WEIGHTED AVERAGE PRICE	LEVELIZED COST (20 YEARS)
2016	$40	$89	2026	$109	$127
2017	$42	$94	2027	$111	$130
2018	$45	$100	2028	$113	$132
2019	$47	$106	2029	$116	$135
2020	$96	$112	2030	$118	$138
2021	$98	$115	2031	$121	$140
2022	$100	$117	2032	$123	$143
2023	$102	$119	2033	$125	$146
2024	$104	$122	2034	$128	$149
2025	$106	$124	2035	$130	$152

Note: Levelized cost assumes 2035 costs continue to escalate at inflation. Costs were levelized assuming a 6.5 percent discount rate.

5.2.5 Utility Scale Financial Screening Results

The annual LCOE supply curves were compared to the levelized annual QF prices with and without ITC in order to determine the amount of capacity with LCOE lower than levelized QF rates each year as shown on Figure 5-4. In 2016, the total potential capacity in the supply curve that can produce energy lower than $89/MWh on a levelized basis is approximately 0.5 GW. This represents only a handful of sites with large capacity. By 2017 and 2018, as the 30 percent ITC is no longer available, there is no capacity with costs lower than the levelized QF rates in either case (No ITC and ITC of 10 percent). Beyond that, the amount of capacity increases as solar PV costs are forecasted to decline, along with increasing levelized cost of QF contracts. By 2035, 7.5 GW (no ITC) and 15.5 GW (ITC) of capacity have LCOE lower than forecasted QF rates.

However, the financial screen does not consider transmission constraints to deliver the power to PGE's service territory. These constraints will be applied in the achievable screen section, discussed next.

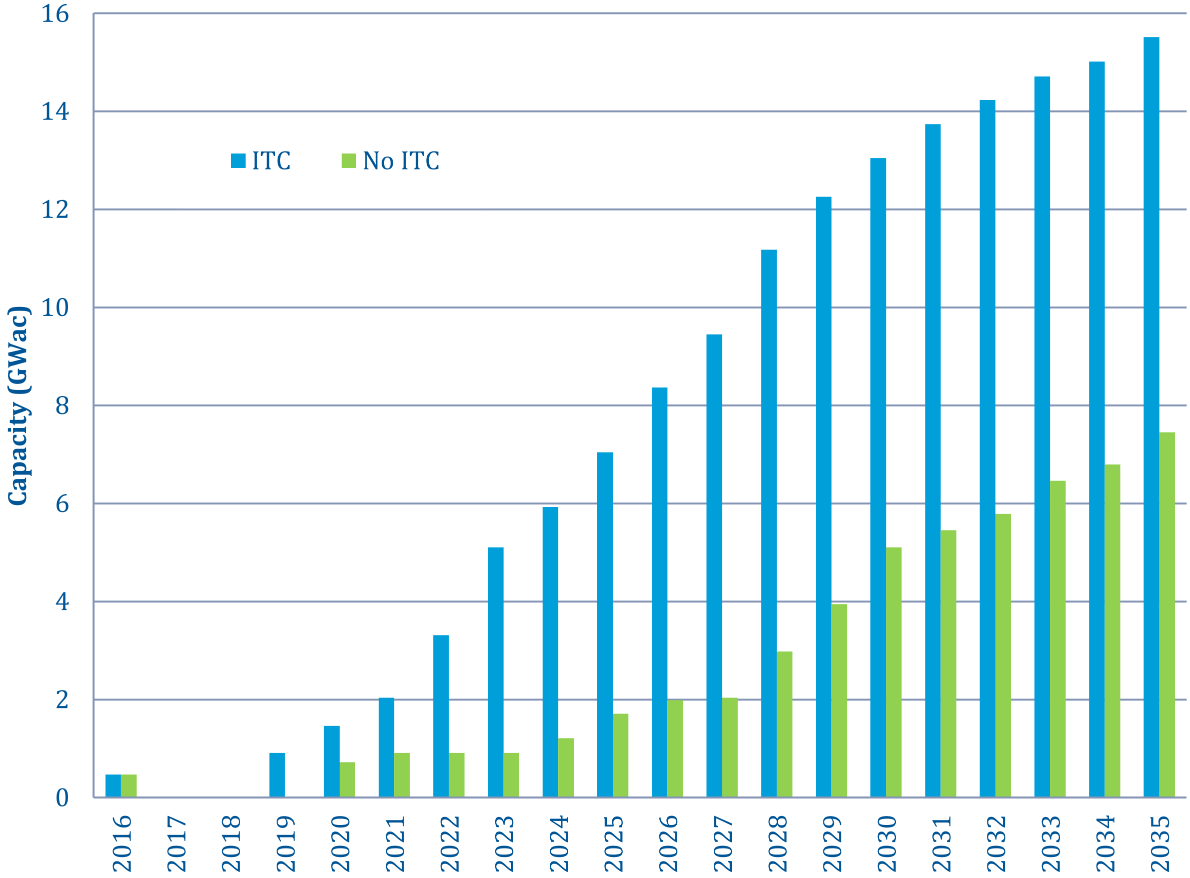


Figure 5-4 **Annual Maximum Utility-Scale Potential after Financial Screen**

5.3 ACHIEVABLE SCREEN

To estimate achievable potential for utility-scale solar, Black &Veatch assumed that the primary constraint is transmission availability. While transmission could be upgraded to deliver solar PV, such upgrades would be relatively expensive given the low utilization rate of solar. With input from PGE, several transmission zones were established for areas where PGE's staff estimated available firm transmission capacity may be available for delivery to PGE's service territory. These zones are denoted on Figure 5-5.

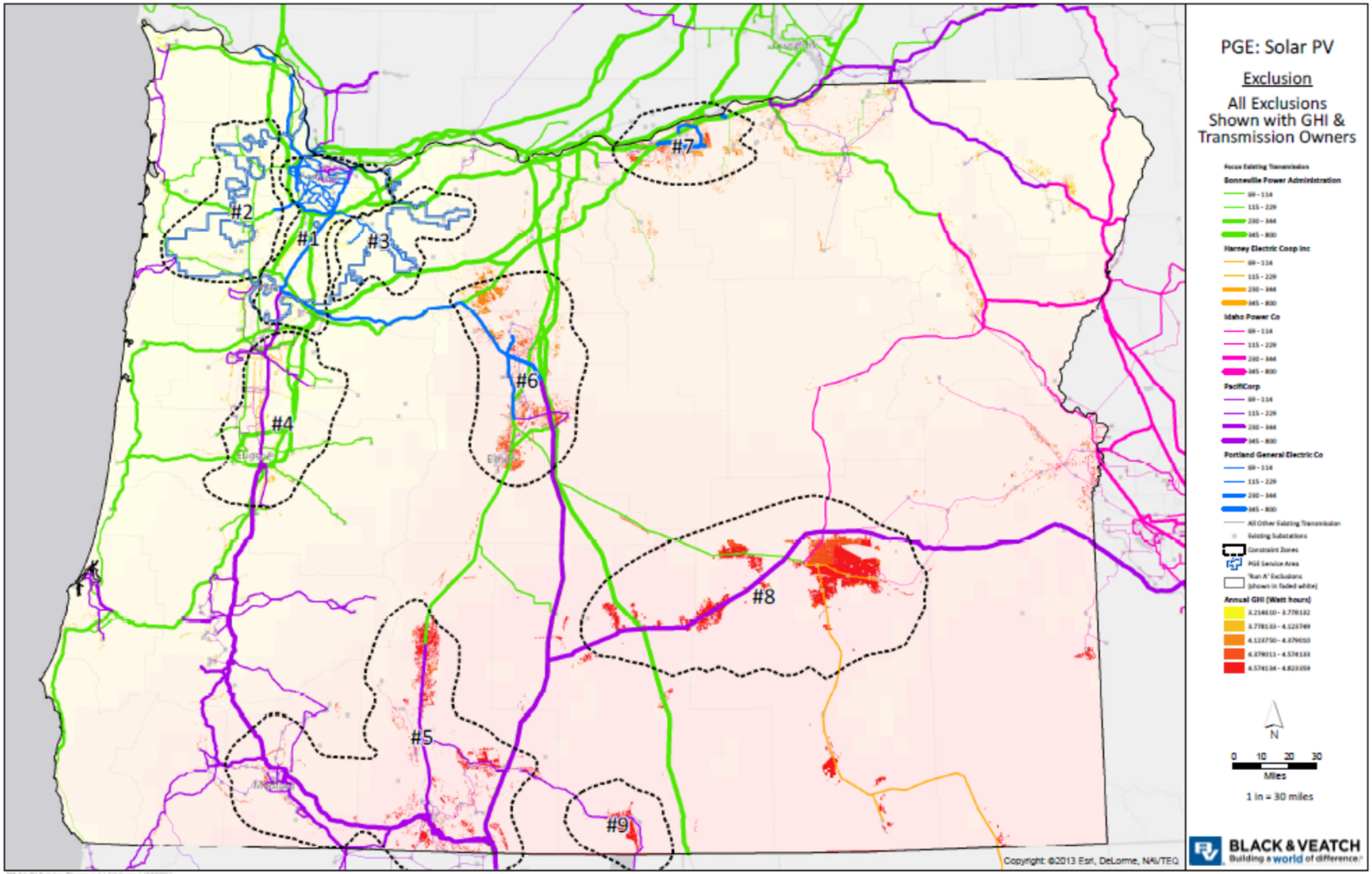


Figure 5-5 **Utility-Scale Solar by Transmission Zone**

Black & Veatch understands that transmission for sending energy from the Pacific Northwest to California is largely allocated, but there is some availability to deliver energy from the south to the north part of Oregon. PGE staff provided estimated maximum incremental transmission capacity that may be available for solar for delivery to PGE by zone and provided guidance on practical system sizes for interconnection by transmission voltage class, as shown in Table 5-7.

Table 5-7 PGE Estimated Available Transmission Capacity by Zone

ZONE	NUMBER OF SYSTEMS CONNECTING AT TRANSMISSION VOLTAGE (PROJECT MAX MW)			ESTIMATED MAX EXPORT CAPACITY BY ZONE	WHEELING REQUIREMENT
	57/69 (10 MW)	115/138 (20 MW)	230 (50 MW)		
No. 1	3-7	6-10	2-4	400 – 500 MW	No wheeling costs applied on PGE line
No. 2	3-5	3-5		200 MW	No wheeling costs applied on PGE line
No. 3	3-4	1-2		100 MW	No wheeling costs applied on PGE line
No. 4	4-5	4-5	2-4	150 MW	Require third party wheeling to PGE
No. 5	5-6	4-5	2-4	200 MW	Require third party wheeling to PGE
No. 6	3-4	4-5	2-3	200 MW	Require third party wheeling to PGE (PGE lines in this zone do not have capacity)
No. 7	2-3	2-4	1-2	200 MW	Require third party wheeling to PGE. (PGE lines in this zone do not have capacity)
No. 8	4-5	2-3		60 MW	Require third party wheeling to PGE
No. 9	2-4			40 MW	Require third party wheeling to PGE

Based on the revised size limitations for individual projects connected at the various voltage classes, the system size at each site and capital cost assumptions were adjusted to accommodate the smaller system size limitation. After applying the size revisions and quantifying only the sites that that fall within each zone in the map, the table below sums up the total remaining potential.

Table 5-8 Utility Solar PV Potential within Zone

ZONE	REVISED POTENTIAL (MWAC)
No. 1	2,223
No. 2	753
No. 3	187
No. 4	3,510
No. 5	4,963

No. 6	3,380
No. 7	325
No. 8	497
No. 9	5
Total	**15,632**

Sites were then identified that met the transmission constraints in Table 5-7 and Table 5-8 and had LCOE that were less than the levelized QF price for that year. Once the estimated maximum export capacity for a zone was met, no additional projects were allowed to be built in the zone. The resulting build-out over time for the ITC and no ITC scenarios are shown on Figure 5-6. The total cumulative adoption of the ITC and no ITC scenarios are 369 MWac and 100 MWac, respectively (Figure 5-7).

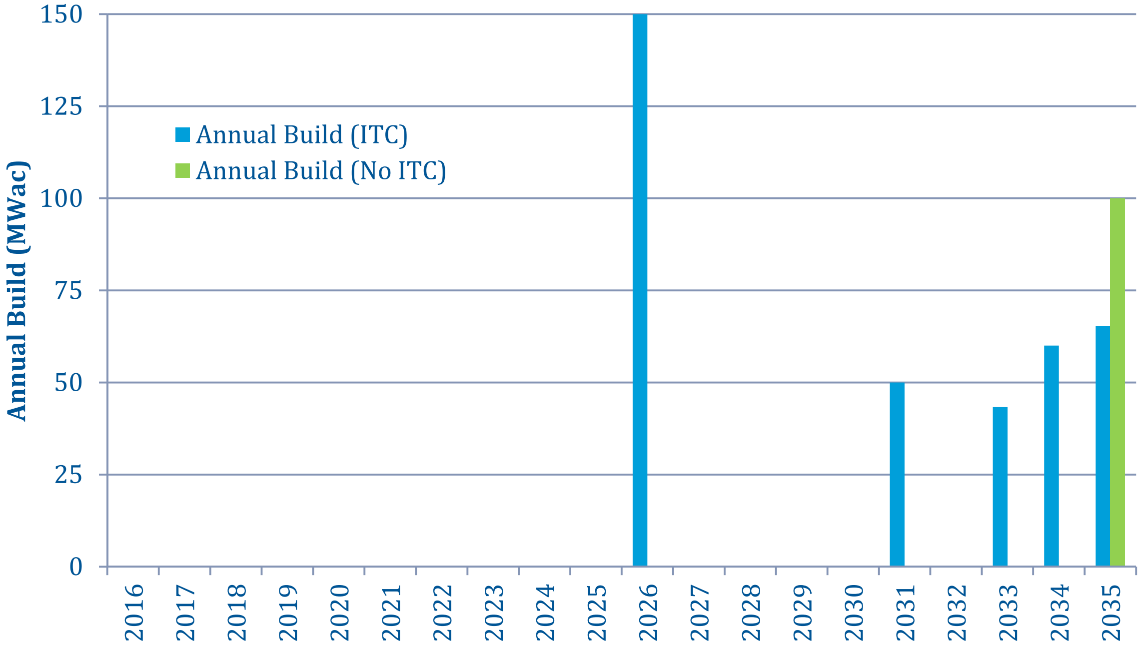


Figure 5-6 **Annual Constrained Build-out of Utility-Scale Solar PV (2016-2035)**

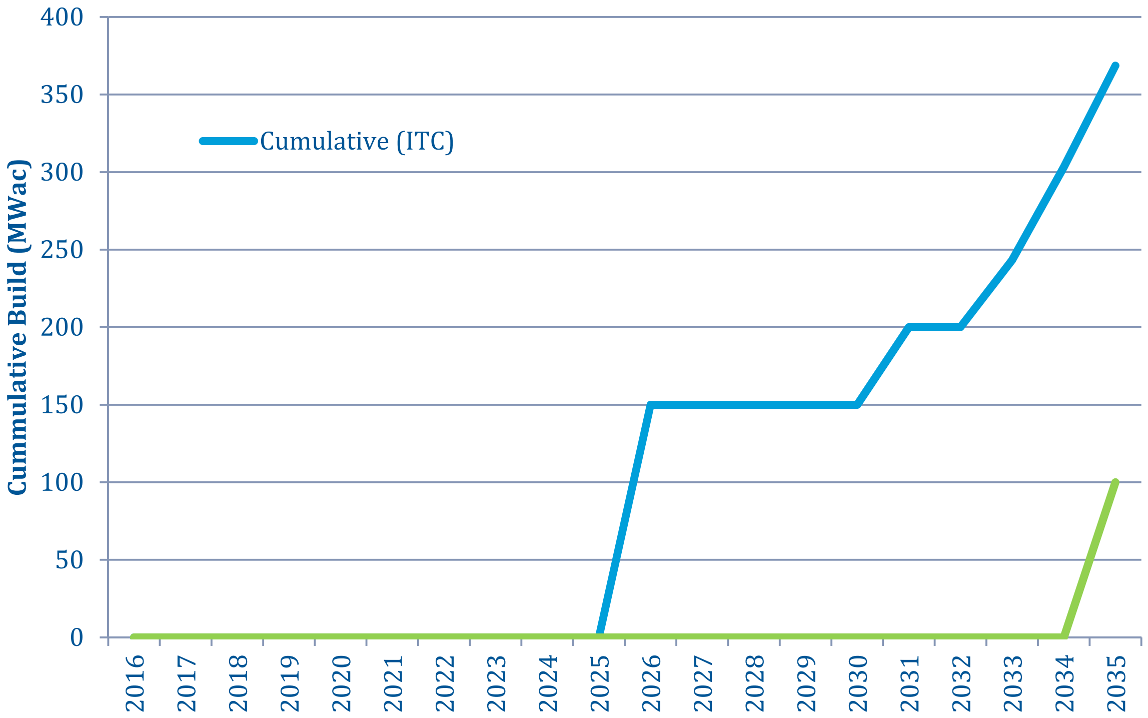


Figure 5-7 **Cumulative Utility-Scale Achievable Solar Penetration**

A detailed breakdown of where systems were deployed is provided in Table 5-9. The most cost-effective zones are 5, 6, and 8, where solar resources are good and systems sizes can be maximized. These are preferred to projects located in Zones 1 to 4, where solar resources are not ideal. The years without any builds indicate that the next lowest cost sites are not yet cost-effective relative to that year's levelized QF prices. The added screen of transmission constraints results in much lower achievable potential due to the combination of smaller systems sizes, thus higher installed cost, and limited capacity on PGE lines, so projects outside of Zones 1, 2, and 3 must incur wheeling costs and losses. .

Table 5-9 Annual Constrained Build-Out of Solar PV by Zone

YEAR	PROJECT ZONE	ANNUAL BUILD (ITC) MWAC	PROJECT ZONE	ANNUAL BUILD (NO ITC) MWAC
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026	#No. 6	150		
2027				
2028				
2029				
2030				
2031	#No. 5	50		
2032				
2033	#No. 5	43		
2034	#No. 6 & #No. 8	60		
2035	#No. 5 & #No. 8	65	#No. 6	100

Appendix A. Solar PV Cost Forecasts

Table A-1 Rooftop Solar Price Projections (2014$/Wdc)

	RESIDENTIAL	COMMERCIAL	
YEAR	4 KWDC	50 KWDC	250 KWDC
2015	$3.74	$2.62	$2.50
2016	$3.37	$2.36	$2.25
2017	$2.71	$2.01	$1.93
2018	$2.38	$1.83	$1.77
2019	$2.18	$1.71	$1.66
2020	$2.03	$1.63	$1.58
2021	$1.91	$1.56	$1.52
2022	$1.82	$1.50	$1.47
2023	$1.75	$1.46	$1.43
2024	$1.68	$1.42	$1.39
2025	$1.63	$1.38	$1.36
2026	$1.58	$1.35	$1.33
2027	$1.54	$1.33	$1.31
2028	$1.50	$1.30	$1.29
2029	$1.47	$1.28	$1.27
2030	$1.43	$1.26	$1.25
2031	$1.41	$1.24	$1.23
2032	$1.38	$1.22	$1.21
2033	$1.35	$1.21	$1.20
2034	$1.33	$1.19	$1.18
2035	$1.31	$1.18	$1.17

Table A-2 **Utility-Scale Solar Price Projections (2014$/Wdc) (source: Black & Veatch analysis)**

YEAR	FIXED 5 MWAC	FIXED 20 MWAC	FIXED 100 MWAC	TRACKING 5 MWAC	TRACKING 20 MWAC	TRACKING 100 MWAC
2015	$1.96	$1.77	$1.69	$2.17	$1.97	$1.88
2016	$1.70	$1.54	$1.47	$1.88	$1.70	$1.63
2017	$1.57	$1.42	$1.35	$1.73	$1.56	$1.49
2018	$1.48	$1.34	$1.28	$1.62	$1.47	$1.41
2019	$1.41	$1.28	$1.22	$1.55	$1.40	$1.34
2020	$1.36	$1.23	$1.17	$1.49	$1.35	$1.29
2021	$1.32	$1.19	$1.14	$1.44	$1.31	$1.25
2022	$1.28	$1.16	$1.11	$1.40	$1.27	$1.21
2023	$1.25	$1.14	$1.08	$1.37	$1.24	$1.19
2024	$1.23	$1.11	$1.06	$1.34	$1.21	$1.16
2025	$1.20	$1.09	$1.04	$1.31	$1.19	$1.14
2026	$1.18	$1.07	$1.02	$1.29	$1.17	$1.12
2027	$1.16	$1.05	$1.00	$1.27	$1.15	$1.10
2028	$1.15	$1.04	$0.99	$1.25	$1.13	$1.08
2029	$1.13	$1.02	$0.98	$1.23	$1.12	$1.06
2030	$1.12	$1.01	$0.96	$1.21	$1.10	$1.05
2031	$1.10	$1.00	$0.95	$1.20	$1.09	$1.04
2032	$1.09	$0.99	$0.94	$1.18	$1.07	$1.02
2033	$1.08	$0.98	$0.93	$1.17	$1.06	$1.01
2034	$1.07	$0.97	$0.92	$1.16	$1.05	$1.00
2035	$1.06	$0.96	$0.91	$1.15	$1.04	$0.99

Appendix B. Distributed Solar Technical Potential Assessment Methodology

TECHNICAL SCREEN

Black & Veatch's methodology for identifying distributed solar PV technical potential throughout PGE's service territory is described in this appendix.

Black & Veatch used publically available LiDAR data and GIS software to identify the amount of technical potential for rooftop solar PV installations available in the PGE service territory.

LIDAR Data and GIS Software Methodology

All GIS analyses were performed using Esri ArcGIS for Desktop Advanced, Version 10.2 plus the Spatial Analyst and 3D Analyst extensions. All-Returns LiDAR data were utilized in this methodology to generate 3D Digital Surface Model (DSM) files for the study area. DSM files were generated at 2 foot resolution. The LiDAR data were collected from several online sources to obtain the best coverage possible for the PGE service territory. Coverage for the greater Portland Metro Area consists of four distinct LiDAR series shown in the Oregon Department of Geology and Mineral Industries (DOGAMI) online map titled "DOGAMI LiDAR Data, Quadrangle (LDQ) Series, Portland Metro Area." The "Portland Pilot" and "Lower Columbia" LiDAR projects were produced in 2004 and 2005, respectively, and those data were retrieved from the Puget Sound LiDAR Consortium (PSLC) website (pugetsoundlidar.ess.washington.edu). The "Oregon City" data, produced in 2004, and the "Portland Metro" data, produced in 2007, were downloaded from the OpenTopography website (www.opentopography.org).

Pre-processing of the All-Returns LiDAR data varied between the LiDAR projects described above. Data downloaded from PSLC are compressed text files (.txt) that were converted first to LASer (LAS) files using LAStools inside ArcGIS v10.2 and then converted to raster format. Data collected from OpenTopography (provided by DOGAMI) was downloaded as compressed LAS files (LAZ) and converted to raster format in ArcGIS. Once decompressed, all of the LiDAR data for this analysis required nearly a terabyte of disk space; however, after converting to raster format, the required disk space was reduced to approximately 200 GB.

Building footprint data were also critical to the GIS methods. Building footprint data for the greater Portland Metro Area were retrieved from the CivicApps for Greater Portland website (www.civicapps.org). Additional building footprint data were collected by contacting city government GIS professionals. Building footprint data were not available for all areas in the PGE service areas, and those areas were excluded from the analysis. Additional data utilized in the analysis included parcel/tax lot data, city boundaries, PGE service territory boundary, United States Geological Survey (USGS) 1:24,000 topo index, USGS 1:12,000 topo index; and other ancillary data.

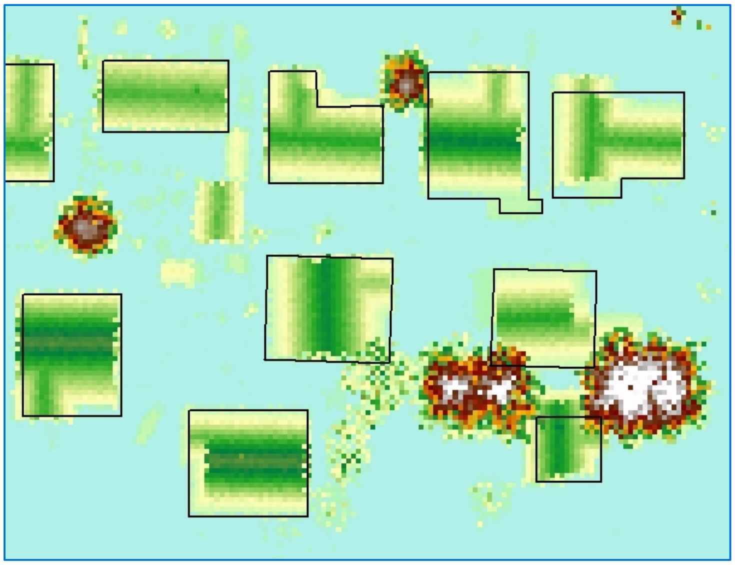


Figure B-1 All-Returns LiDAR-Derived Digital Surface Model (DSM)

The process for distilling All-Returns LiDAR and building footprints data into suitable PV mounting planes is fairly complex. For purposes of description, it is best to break the process into three main components:

1. Run the Point Solar Radiation tool in ArcGIS to calculate monthly/annual watt-hour per square meter (Wh/m^2).
2. Extract mounting planes.
3. Calculate monthly shading factors for each extracted mounting plane.

These steps are described in the following sections.

Point Solar Radiation

The ArcGIS for Desktop Advanced tool called Point Solar Radiation was run for all pixels within the building footprints (2 foot resolution). The settings used allowed values of direct radiation to be compared and the shading effects from obstacles such as trees, chimneys, HVAC equipment, nearby structures, and topography within 400 feet of the building edges to be measured. Before choosing a 400 foot "sky size," Black & Veatch evaluated the effects of shading from obstacles farther away, particularly major topographic features, and their effect on rooftop solar radiation is very low compared to obstacles within 400 feet of the building edges. Refer to Figure B-2 for an example of Point Solar Radiation results.

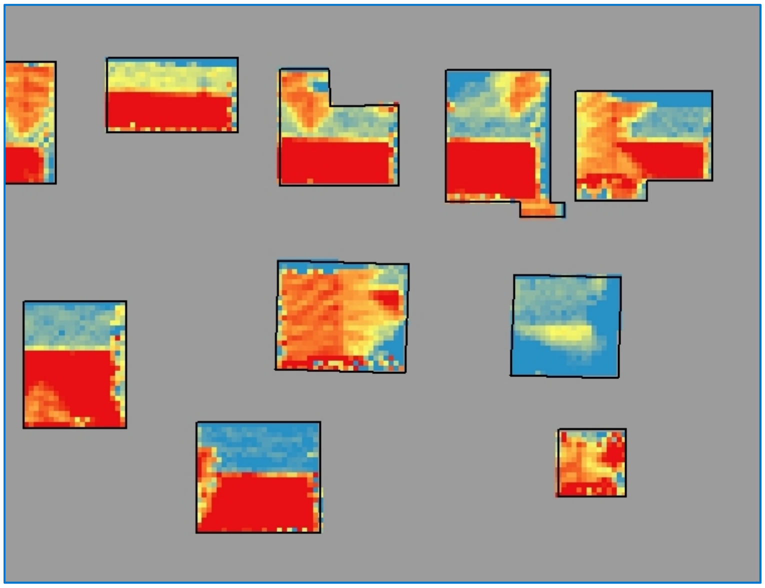


Figure B-2 Example of Point Solar Radiation Results (cool colors – lower insolation)

In the figure above, cool colors indicate relatively lower insolation. Effects of azimuth, tilt and shading are clearly shown.

Extracting Mounting Planes

Black & Veatch has developed a complex geoprocessing algorithm to extract rooftops areas that are likely suitable for rooftop PV. There are many inputs for this geoprocessing model: DSM generated from All-Returns LiDAR data; building footprints; Point Solar Radiation results; tax lots; tilt/slope (generated from DSM during processing); and azimuth/aspect (generated from DSM during processing). The geoprocessing model includes logic to process roof planes differently according to their attributes; for example, the process distinguishes between flat roof areas and tilted roof areas and applies logic accordingly. Additionally, incorporating land use data allows the model to process single-family residential (SFR) buildings differently than commercial buildings, including calculating larger setbacks from the roof plane edges. Refer to Figures B-3, B-4, and B-5.

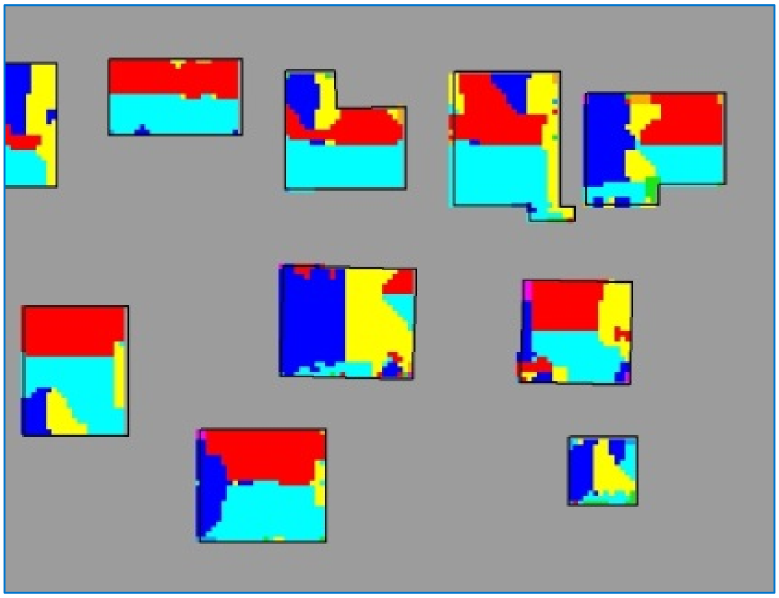


Figure B-3 Example Azimuth Values (colors indicate different azimuths)

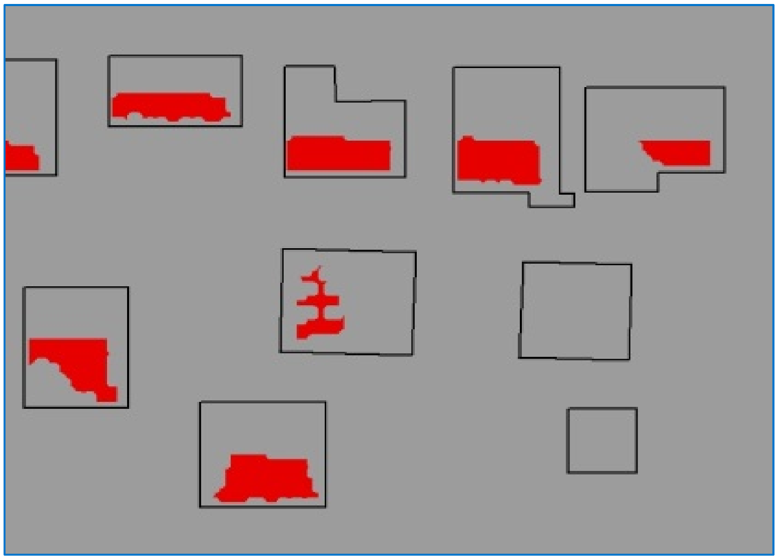


Figure B-4 Tilted Roof Planes Meeting Solar Cutoff and Setback Requirements (red areas indicate areas meeting cutoff and setback requirements)

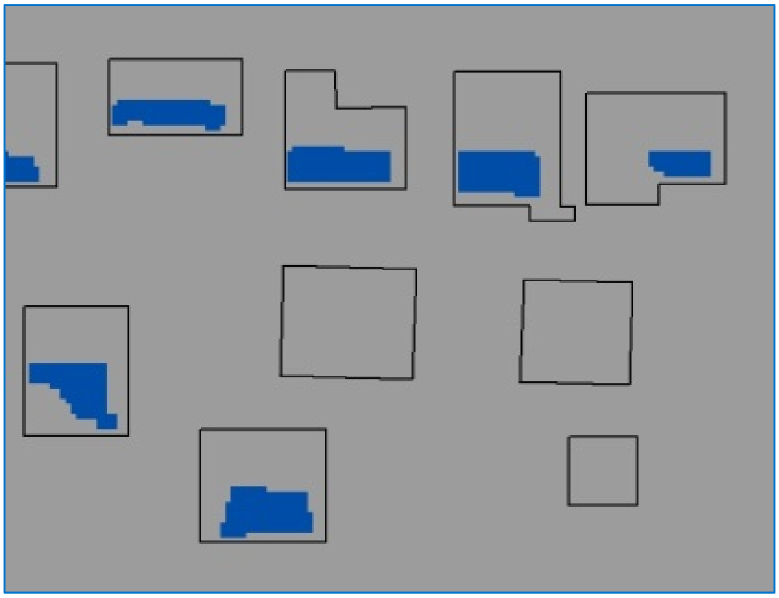


Figure B-5 **Tilted Roof Planes After Filtering for Geometric Requirements (blue areas indicate areas meeting geometric requirements)**

Calculate monthly shading factors

Each mounting plane identified through the process above then goes through a process to have monthly shading factors calculated. Conceptually, the process is to find all of the points output from the Point Solar Radiation tool that overlap the extracted mounting plane. The mean values of the monthly solar radiation values are then used to determine monthly shading factors to be input into SAM. Black & Veatch has developed custom procedures in GIS to iteratively handle these calculations, as it involves billions of points of information and is extremely processing-intensive.

Development of Filters and Exclusions

Black & Veatch eliminated rooftops according to several filters and exclusions. The filters and exclusions are intended to discount the identified roof area for various accessibility requirements, identify practical roofs, and eliminate areas that have attributes that negatively impact the energy production capability of a site. These filters and exclusions are described in the sections below.

Minimum Roof Size

Black & Veatch filtered roofs to exclude roofs with an area below 400 square feet. This was done to eliminate structures such as separate garages that likely do not have a large load or a separate meter and are less likely to have a solar PV system installed than larger structures such as houses.

Setbacks

Black & Veatch applied setbacks to identified rooftops. These setbacks, summarized below, are intended to account for possible fire code and other access requirements for each site. These requirements are largely based on the California Department of Forestry and Fire Protection requirements for solar PV systems, and Black & Veatch finds that some utilities and jurisdictions require at least partial compliance with this code. In discussions with PGE, it was learned that PGE may consider requiring these setbacks for self-owned systems:

- Residential Systems
  - 2 foot setbacks from all edges of the roof[18]
- Commercial Systems
  - 6 foot setbacks around perimeter of roof[19]

Contiguous Area

In order to identify efficient and practical roofs for solar PV development, Black & Veatch identified a minimum contiguous area. This allows the elimination of roofs that may pass other filters and exclusions but are otherwise impractical because they are overall small for a cost-effective installation, or have a section too small for a solar PV module.

To identify the minimum contiguous area, Black & Veatch estimated that a typical 60 cell solar PV module has approximate dimensions of 4 feet by 6 feet. A typical capacity for a 60 cell module is roughly 250 W. With these metrics, a 1.0 kW system (4 - 250 W modules) has an area of approximately 100 square feet. Therefore, the minimum contiguous area was set to 100 square feet, which is effectively a minimum system size of 1.0 kW.

Similarly, a minimum length was set for each side of the contiguous area to be equal to the shortest side of a typical panel, 4 feet, to avoid unrealistically slim areas where a panel may not fit.

Available Solar Resource

Roofs that do not receive adequate solar resource were eliminated from the analysis. Solar resource access on roofs may be limited by objects that cause shading such as trees and buildings or from poor roof orientation such as tilt and azimuth.

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[18] Black & Veatch notes that the California Department of Forestry and Fire Protection requires a 3 foot setback from edges and eaves of roofs, and no setback from the roofs bottom edge. To efficiently capture this in GIS, Black & Veatch assumed a 2 foot setback from all edges of each roof.

[19] Other typical setback or access requirements, such as setbacks from skylights and other roof objects, and walkways are accounted for in Black & Veatch's conversion from area to kW capacity, and in the approach to incorporate TSRF.

The ETO has a shading and orientation requirement for systems that wish to receive their solar incentive. This factor, called the Total Solar Resource Fraction (TSRF), must be 75 percent or above for each point in an array[20,21]. Black & Veatch incorporated this cutoff into the technical screen.

Conversion to Technical Potential

Black & Veatch converted the available area identified with GIS to a kWdc capacity. For tilted rooftop systems, the conversion factor used was 10 W per square foot. For flat roofs, modules would be tilted at 10 degrees and require spacing between rows. Therefore, for flat roofs, Black & Veatch implemented a conversion factor of 5.8 W per square foot.

FINANCIAL SCREEN

The following section discusses development of assigning rate classes and sites and energy modeling assumptions.

Building Load Profiles

Load profiles for commercial and industrial customers (C&I) influence the financial results of the analysis since C&I customers are generally under rates with demand charges; whereas, residential customers are not. Load profiles for C&I customers were determined based on a statistical sampling of customers within the PGE service territory. The Commercial Building Energy Consumption Survey (CBECS) provides building characteristics for different regions throughout the US by the Energy Information Administration (EIA). Buildings are classified according to principal activity, which is the primary business, commerce, or function carried on within each building. The 2003 CBECS data were chosen since this is the most recent and complete survey available from EIA[22]. The EIA defines building types in the Pacific Northwest. A distribution of building types in the Pacific Northwest is shown on Figure B-6.

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[20] From ETO's Program Guide for Solar Electric Allies "The TSRF calculation must reflect the worst location on the array(s)—the location with the lowest TSRF value—and be 75% or greater in order to qualify for Program incentives."

[21] From ETO's Solar Electric Installation Requirements "Total Solar Resource Fraction ("TSRF") shall be 75% or greater at all points on the array for string inverters. Projects may include individual modules with a TSRF of less than 75% if the modules are electrically isolated from one another using microinverters; however, those modules that do not meet the 75% requirement will not be eligible for program incentives." Black & Veatch assumed most systems would not use microinverters and, therefore, assumed that all of the array must meet the 75% requirement.

[22] There is a 2012 survey, but that dataset will not be available in its entirety until late next year.

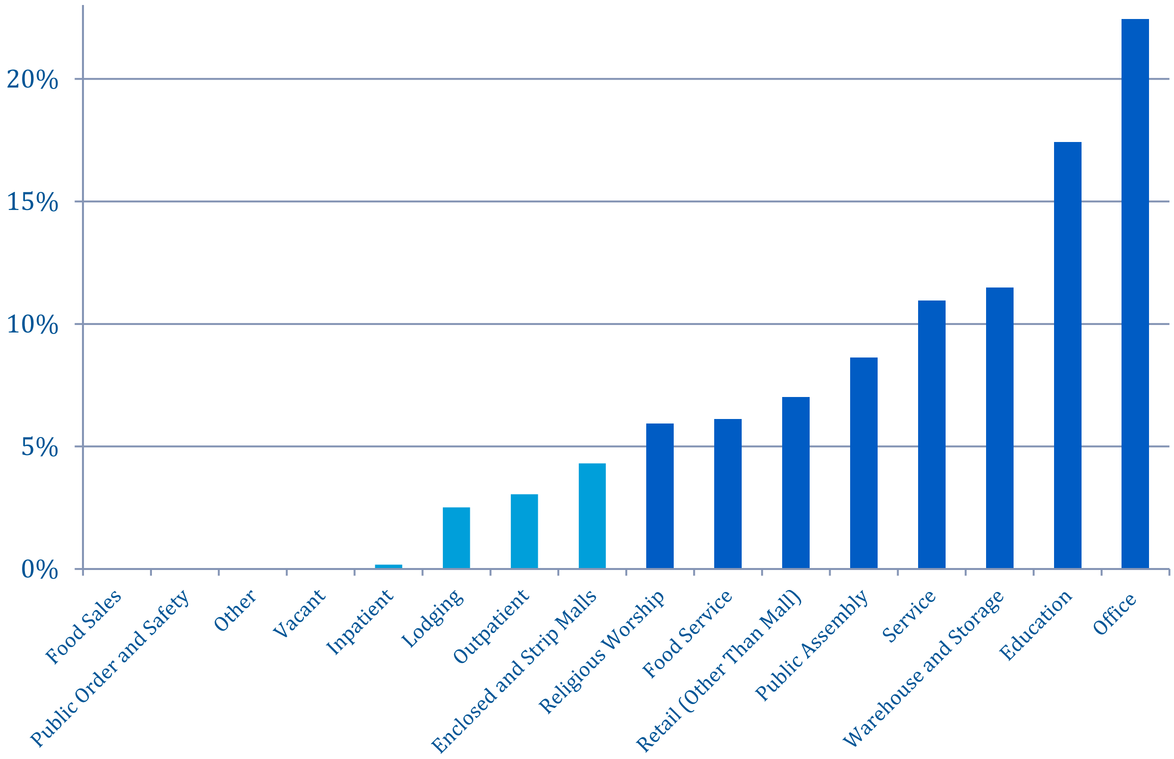

Figure B-6 **Distribution of Buildings for the Pacific Northwest (source: EIA)**

Black & Veatch used the top eight building types to model the hourly load profiles indicative of the PGE service territory utilizing the DOE's Energy Plus model. Energy Plus is a whole building energy simulation program that engineers, architects, and researchers use to model energy and water use in buildings. From the load profile outputs of Energy Plus, Black & Veatch determined the load factor for each building given, as follows:

$$Load\ Factor\ (\%) = \frac{Annual\ Average\ Load\ (kWh)}{Annual\ Peak\ Load\ (kWh)} * (100)$$

The average load factor weighted by number of buildings for the top 8 buildings compromising 90 percent of the building stock was then determined as shown in Table B-1.

Table B-1 Load Factor by Building Type

BUILDING TYPE	LOAD FACTOR
Religious Worship	22%
Retail (other than mall)	37%
Public Assembly	28%
Service	49%
Food Service	37%
Warehouse	32%
Education	31%
Office	37%
Weighted Average	**35%**

For the building analysis, Black & Veatch utilized the electricity consumption energy intensity within the CBECS dataset. This dataset provides different energy intensity metrics for different climate zones throughout the US.

The weighted average load factor given in Table B-1 was used to determine approximately what demand (kW) corresponds to a given amount of floor space as defined from the technical suitability portion of the analysis. Interpolating between high and low demand data points was done to back into the range of building square footage that would yield the appropriate applicability requirements for each rate class.

Energy Production Model Assumptions

Table B-2 summaries system parameters and loss assumptions made for distributed generation systems in the energy production analysis. These assumptions are largely based on typical parameters seen in the industry.

Table B-2 Distribution Scale Production Modeling Assumptions

INPUTS	ASSUMPTION	REASONING
System DC Size	Changes by customer	Technical output from GIS LiDAR analysis.
Module Type	Standard	Polycrystalline.
Inverter Loading Ratio	1.1	
Inverter Efficiency	97%	
Array Type	Fixed roof mount	
Tilt	Varies by customer	Technical output from GIS LiDAR analysis.
Azimuth	Varies by customer	Technical output from GIS LiDAR analysis.
Ground Coverage Ratio	56%	Only applies to flat roofs where modules are assumed to be tilted to 10 degrees.
Soiling	1%	Black & Veatch ran its proprietary soiling model for a system west of the Cascade Mountains, where PGE's service territory primarily resides. The weather patterns west of the Cascades are fairly consistent and, therefore, Black & Veatch applied the same soiling loss to systems in PGE's service territory.
Shading	Changes by customer	For distributed generation systems, shading from nearby trees, buildings and terrain is accounted for on a monthly basis.
Snow	0%	Accounted for in Black & Veatch's soiling loss parameter.
Mismatch	1%	
Wiring	1.5%	Black & Veatch estimates 2 percent for wiring and connection losses. This value is split between wiring and connection losses in SAM.
Connections	0.5%	See above.
Light-Induced Degradation	1.5%	Typical for polycrystalline.
Nameplate	0.5%	
Age	0.35%	Degradation seen during the first year.
Availability	99%	
Degradation	0.7%/year	

Appendix C. Federal and Oregon State Incentives

To help offset solar system installation costs and facilitate adoption of PV in the state, federal and state incentives are available to residential and business customers, although nearly all are set to expire or are subject to annual adjustments. Oregon also provides a property tax exemption for solar PV systems. Tables C-1 and C-2 summarize the incentives available to residential and commercial customers in 2014 and anticipated or proposed levels for 2015.

Table C-1 Residential Customer Incentives

INCENTIVE	2014 INCENTIVE/FUNDING	2015 INCENTIVE/ FUNDING
Federal Residential Investment Tax Credit (ITC)	30% of installed cost	30% of installed cost
Oregon Residential Energy Tax Credit[23]	Lower of $1.90 per W/ $6,000/50% of installed cost (up to $1500 per year)	Lower of $1.70 per W/ $6,000/50% of installed cost (up to $1500 per year)
Energy Trust of Oregon (ETO) Residential Incentives	Stepped down from $1.00 per W to $0.90 per W (Maximum of $9,500 per customer) Total 2014 budget: $5,390,000[24]	Stepped down from $0.95 per W to $0.82 per W. Total 2015 Budget: $3.0 million[25]

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[23] Summary of HB 3672 (2011) Tax Credit Extension Bill http://www.oregon.gov/ENERGY/CONS/docs/HB3672summary.pdf.

[24] ETO Incentive Status Report for PGE (Dec. 15, 2014) http://energytrust.org/library/forms/Solar_Status_Report.pdf.

[25] Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

Table C-2 Business Customer Incentives

INCENTIVE	2014 INCENTIVE/FUNDING	2015 INCENTIVE/ FUNDING
Federal Business Investment Tax Credit (ITC)	30% of installed cost	n/a
Modified Accelerated Depreciation (MACRS)	5 years	n/a
Oregon Renewable Energy Development (RED) Grant26	Competitive Bid for multiple RE technologies (max of $250,000 or 35% of project cost) Total 2014 Funding: $1,500,000	$1,500,000
Energy Trust of Oregon (ETO) Business Incentives	$1.30 to $0.70 per W (size dependent) (max of $180,000) Total 2014 Funding: $4,600,00027	$1.30 to $0.70 per W (size dependent), step down $1.20 to $0.66 per W (size dependent) Total 2015 Budget: $3.0 million 28

Figure C-1 shows the changes to these incentives over time, as the federal ITC is set to expire by the end of 2016, and the Oregon tax credits and grants are set to expire by the end of 2017. The ETO incentive programs are also adjusted annually to step down over time to account for declining cost of solar over time.

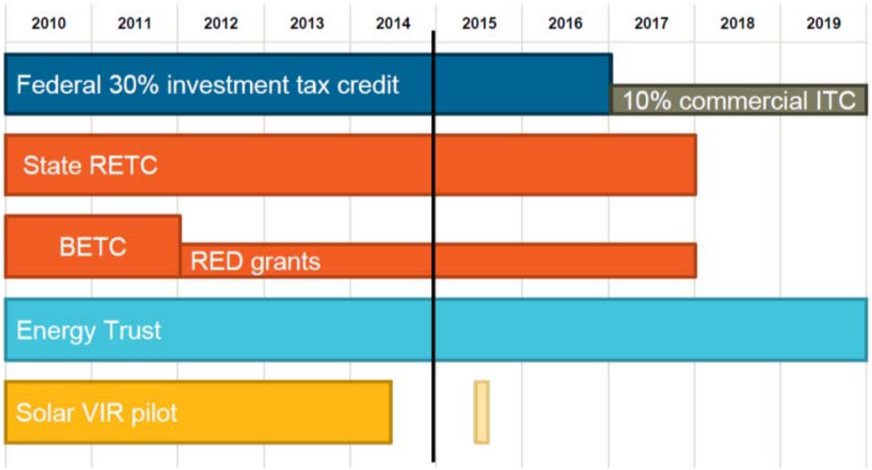

Figure C-1 Incentives for Oregon Solar Projects (source: ETO)

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[26] Summary of HB 3672 (2011) Tax Credit Extension Bill http://www.oregon.gov/ENERGY/CONS/docs/HB3672summary.pdf.

[27] ETO Incentive Status Report for PGE (Dec. 15, 2014) ETO Incentive Status Report for PGE (Dec. 15, 2014).

[28] [28] Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

Appendix D. Results

Table D-1 Annual Solar Distributed Generation Adoption by Customer and Scenario (MWdc)

RATE CASE	CPI						CPI+1					
SCENARIO APPROACH	ADOPTION CURVE		ETO FUNDING (NO TAX CREDITS)		ETO FUNDING (WITH TAX CREDITS)		ADOPTION CURVE		ETO FUNDING (NO TAX CREDITS)		ETO FUNDING (WITH TAX CREDITS)	
CUSTOMER CLASS	COM	RES	COM	RES	COM	RES	COM	RES	COM	RES	COM	RES
2016	1.80	2.40	4.91	2.41	4.91	2.41	4.81	4.23	4.96	4.24	4.96	4.24
2017	4.37	8.83	2.89	5.19	3.20	9.93	5.23	11.15	2.96	5.38	3.65	10.44
2018	4.16	11.09	3.31	2.00	4.12	13.77	5.03	13.55	3.45	2.09	4.30	15.48
2019	3.49	12.39	3.65	2.33	4.57	12.83	4.48	15.75	3.86	2.48	4.86	15.13
2020	2.46	12.48	3.94	2.64	4.95	10.14	4.12	16.74	4.23	2.86	5.37	12.17
2021	1.86	11.54	4.19	2.94	5.29	7.85	3.02	16.29	4.58	3.26	5.86	9.48
2022	0.95	9.79	4.42	3.23	5.59	6.23	1.97	14.58	4.91	3.68	6.32	7.54
2023	0.88	7.64	4.62	3.52	5.85	5.10	1.74	12.02	5.22	4.12	6.77	6.20
2024	0.93	5.49	4.80	3.81	5.42	4.87	1.94	9.16	5.53	4.60	7.20	6.06
2025	0.94	5.35	4.96	4.10	2.25	5.31	2.08	6.44	5.82	5.12	6.52	6.89
2026	0.00	5.62	5.11	4.40	1.37	5.76	2.16	4.12	6.11	5.69	2.04	7.85
2027	0.00	5.71	1.53	4.70	0.92	6.23	0.00	2.34	6.39	6.32	1.11	8.96
2028	0.00	4.48	0.71	5.00	0.63	6.71	0.00	1.07	1.54	7.03	0.73	10.28
2029	0.00	0.00	0.44	5.31	0.43	7.23	0.00	0.17	0.59	7.84	0.49	11.89

RATE CASE	CPI						CPI+1					
SCENARIO APPROACH	ADOPTION CURVE		ETO FUNDING (NO TAX CREDITS)		ETO FUNDING (WITH TAX CREDITS)		ADOPTION CURVE		ETO FUNDING (NO TAX CREDITS)		ETO FUNDING (WITH TAX CREDITS)	
CUSTOMER CLASS	COM	RES	COM	RES	COM	RES	COM	RES	COM	RES	COM	RES
2030	0.00	0.00	0.29	5.63	0.29	7.77	0.00	0.00	0.34	8.77	0.33	13.90
2031	0.00	0.00	0.19	5.96	0.19	8.34	0.00	0.00	0.22	9.84	0.22	6.21
2032	0.00	0.00	0.13	6.30	0.13	8.95	0.00	0.00	0.15	11.11	0.15	3.57
2033	0.00	0.00	0.09	6.65	0.09	7.80	0.00	0.00	0.10	12.64	0.10	2.41
2034	0.00	0.00	0.06	7.02	0.06	4.84	0.00	0.00	0.07	14.51	0.07	1.65
2035	0.00	0.00	0.01	7.39	0.01	3.33	0.00	0.00	0.01	16.86	0.01	1.12
Subtotal	***21.83***	***102.80***	***50.26***	***90.54***	***50.26***	***145.38***	***36.57***	***127.60***	***61.04***	***138.45***	***61.04***	***161.47***
Total	124.63		140.80		195.64		164.17		199.50		222.52	

Appendix E. Utility-Scale Solar Potential Assessment Methodology

TECHNICAL SCREEN

Black & Veatch identified areas appropriate for utility-scale solar PV development by excluding areas of the state based on several criteria. These criteria were intended to exclude areas that are less likely to be developed because of environmental concerns, terrain, proximity to transmission, and other factors. Because the potential for solar development is so large, the exclusions applied are relatively restrictive. Development of solar PV could be possible in areas shown as excluded on in these maps (such as farmland), but other areas may be preferred.

All exclusion areas were merged together and removed from the overall state boundary. The result of this was further filtered by contiguous acreage, removing any land with a contiguous acreage of less than 25 (approximately 5 MWdc).

The exclusions implemented by Black & Veatch are summarized in the following sections:

- Environmental Screens (EDTF Categories 3 and 4).
- Sage Grouse Habitat.
- Publicly Owned and Park Lands.
- Land Use.
- More than 5 Miles from Transmission Lines.
- Land with Slope Greater than 5 Percent.

Environmental Screens

The WECC created the Environmental Data Task Force (EDTF) to map environmental sensitivities of lands across the west. The EDTF has created the most comprehensive, stakeholder-vetted dataset of environmental restrictions for energy development in the west. The EDTF maintains data to support the identification of land appropriate for transmission line development. While the initial purpose was for transmission siting, similar development constraints would apply to solar PV projects.

The EDTF data consists of four categories, summarized in Table E-1.

Table E-1 EDTF Categories

CATEGORY	DESCRIPTION
Category 1	<u>Least Risk of Environmental or Cultural Resource Sensitivities and Constraints</u>: Areas with minimal identified environmental or cultural resource constraints and/or with existing land uses or designations that are compatible with or encourage transmission development. These areas would present few or minimal environmental and cultural mitigation requirements and are least likely to result in project delays.
Category 2	<u>Low to Moderate Risk of Environmental or Cultural Resource Sensitivities and Constraints</u>: Areas where development may encounter one or more environmental or cultural resource sensitivity or constraints that would require low to moderate permit complexity or mitigation costs. This category also includes areas in the Protected Areas Database of the United States (PAD-US) dataset that have an unknown land use designation or degree of restriction to transmission development.
Category 3	<u>High Risk of Environmental or Cultural Resource Sensitivities and Constraints</u>: Transmission development is likely to encounter one or more environmental or cultural resource sensitivities or constraints that will substantially increase permitting complexity and which could result in project delays and high mitigation costs. This category also includes areas identified as avoidance areas (based on environmental and cultural sensitivities) in Canada from the Western Renewable Energy Zones (WREZ) Phase 1 Report.
Category 4	<u>Areas Presently Precluded by Law or Regulation</u>: Areas where transmission development is presently precluded by federal, state, or provincial law, policy, or regulation, and areas identified as exclusion areas (based on environmental and cultural sensitivities) in Canada from the WREZ process.

Source: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Environmental-and-Cultural-Considerations.aspx

Black & Veatch excluded Categories 3 and 4, as these represent precluded or high-risk areas for development. EDTF Categories 3 and 4 are shown on Figure E-1 in orange. Remaining uncolored areas are Categories 1 and 2.

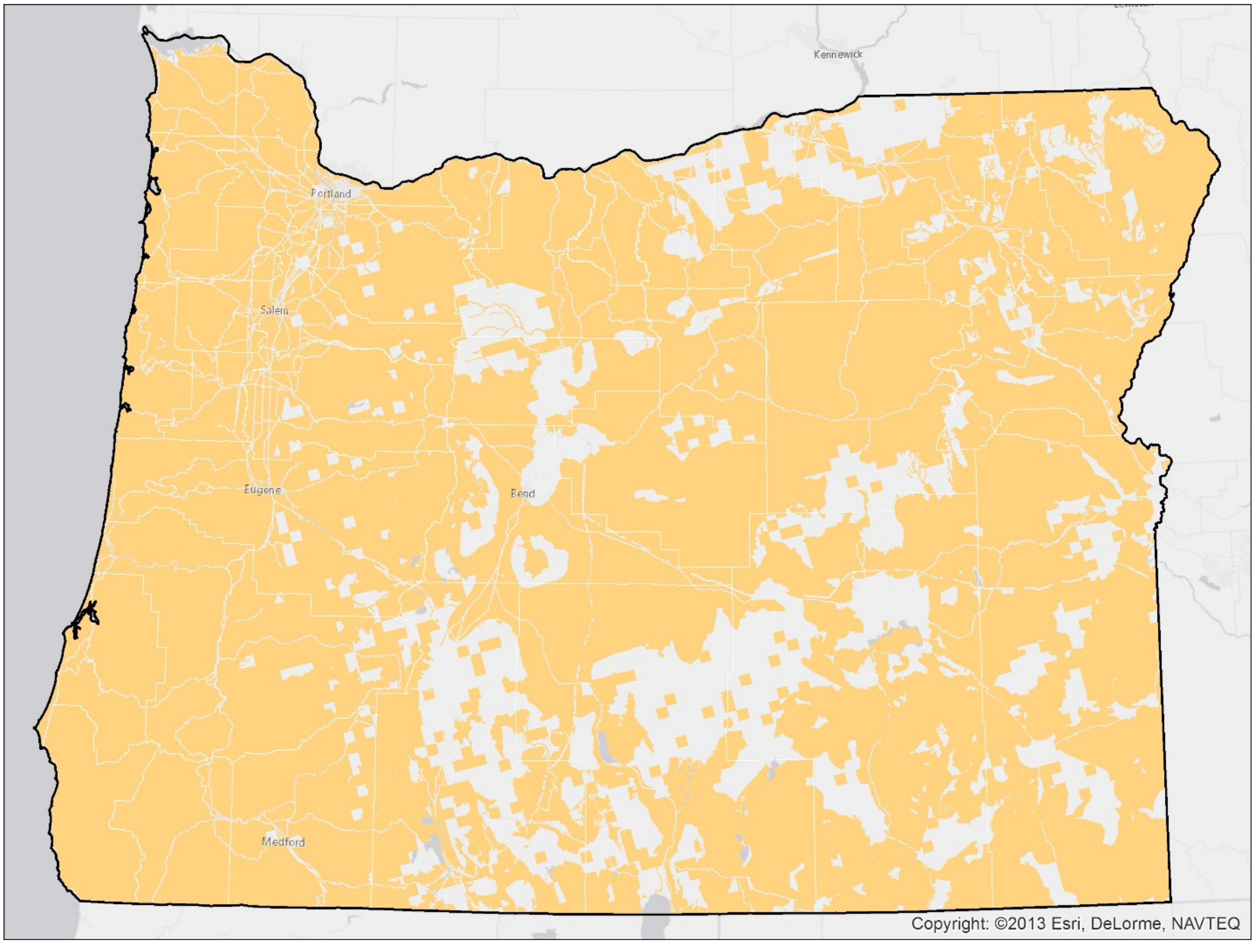


Figure E-1 EDTF Categories 3 and 4

Sage Grouse

Sage grouse is a bird that dwells in sagebrush. The species is a candidate for listing under the Federal Endangered Species Act, and there are significant efforts to conserve sage grouse habitat. Therefore, sage grouse habitat areas were excluded from this analysis. Figure E-2 shows the sage grouse habitat in Oregon.

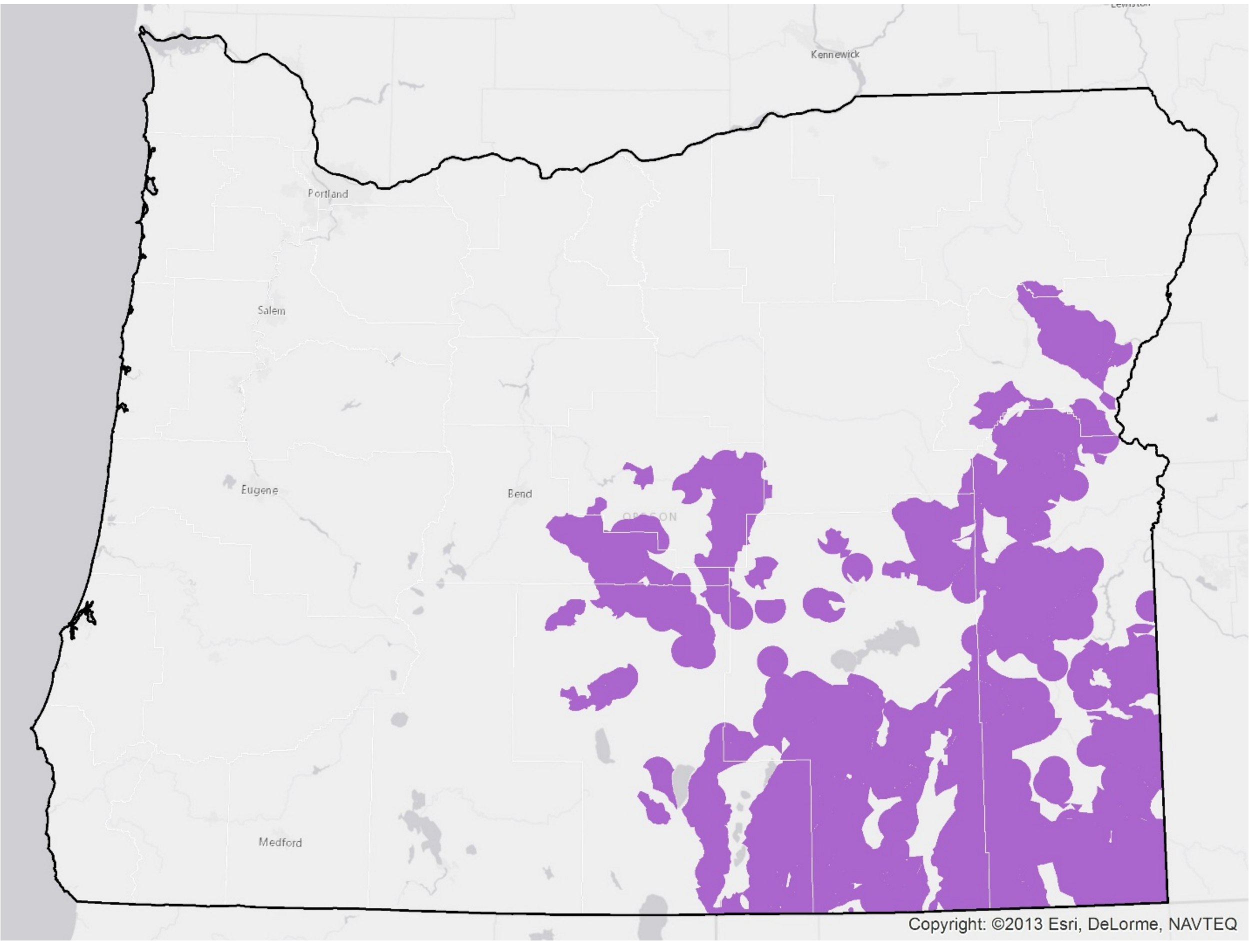
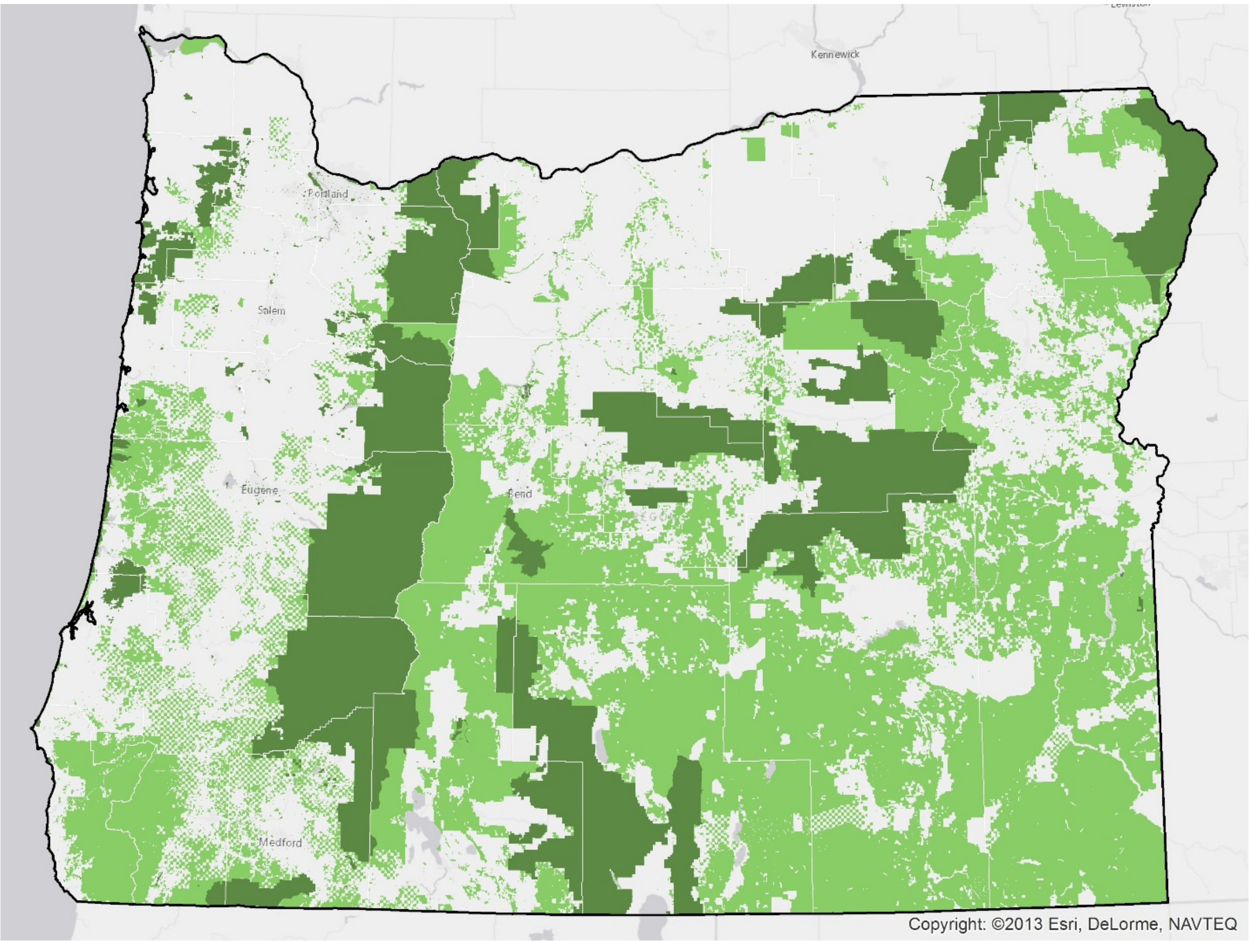


Figure E-2 Sage Grouse Habitat

Public Ownership & Parkland

Black & Veatch also eliminated land owned by the Bureau of Land Management (BLM), Department of Defense (DOD), Forest Service, and Fish and Wildlife Service. These areas are identified on Figure E-3.



Copyright: ©2013 Esri, DeLorme, NAVTEQ

Figure E-3 Public Ownership & Parkland

Land Use

Black & Veatch also eliminated lands based on their usage. Lands that are bodies of water, have low development, medium and high density (urban), forested, cropland, or wetlands were excluded from this analysis. Lands that fall into these land use categories are shown on Figure E-4.

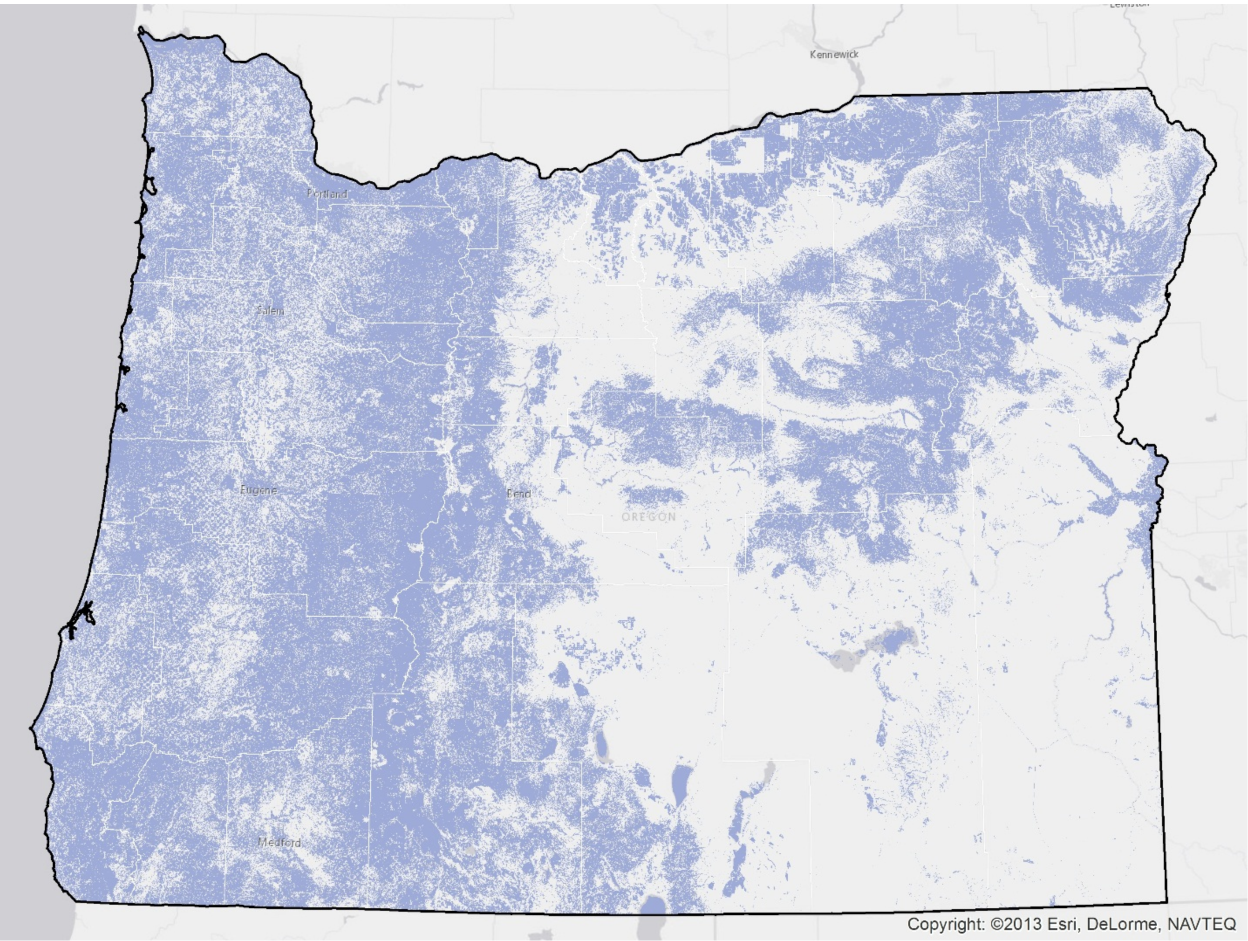


Figure E-4 **Water, Developed Low, Medium and High Density, Forests, Cropland, and Wetlands (Land Use)**

Distance to Transmission

Black & Veatch focused on appropriate lands within 5 miles of existing electric transmission. Sites further than 5 miles are not expected to be financially viable because of the need to build long generation interconnection lines. An image illustrating areas outside of 5 miles from transmission lines is shown on Figure E-5.

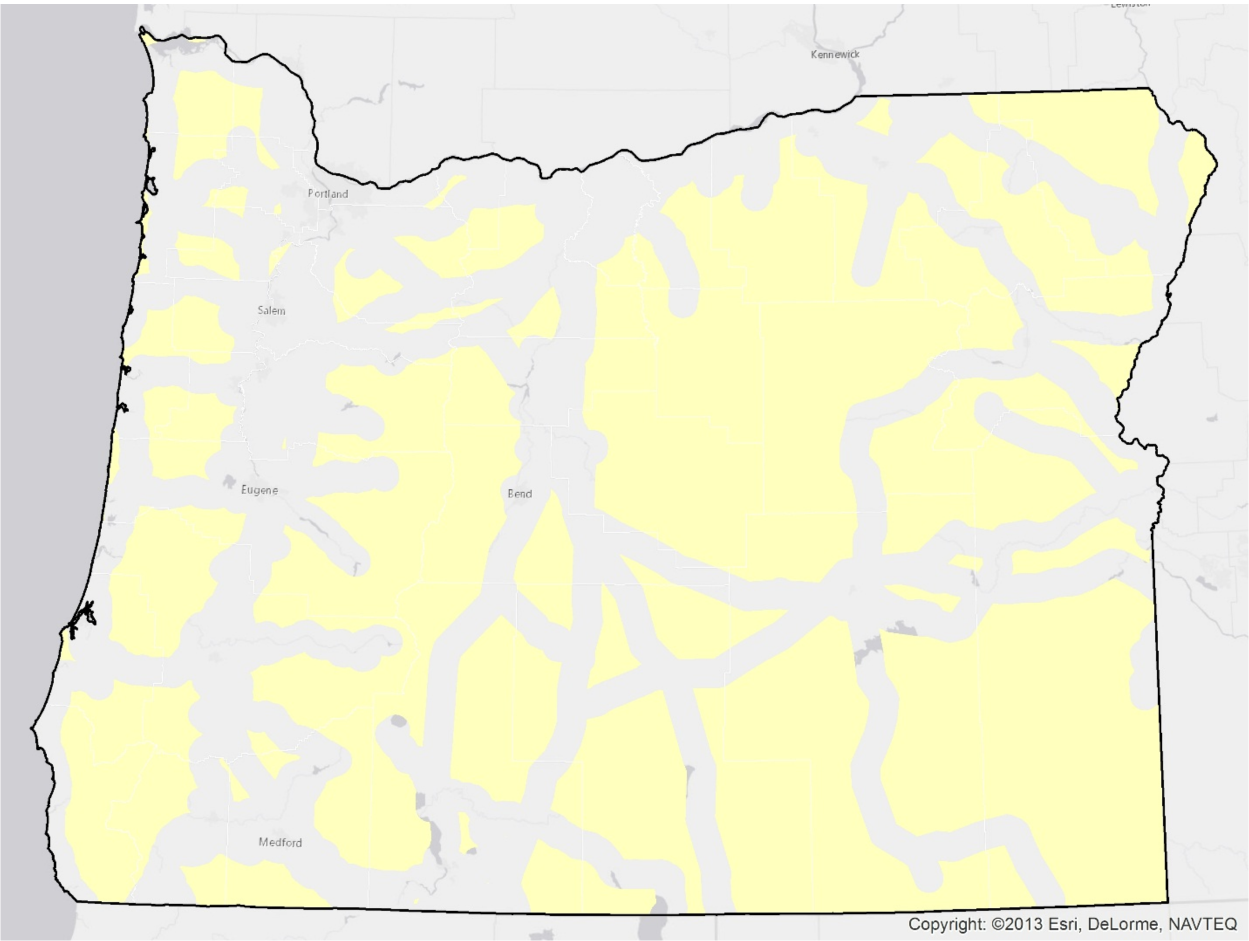


Figure E-5 **More than 5 Miles from Transmission Lines**

Land Slope

Ground-mounted solar PV projects are generally installed on relatively flat land. This is because the mounting systems often cannot accommodate drastic slopes and because sloped land may negatively alter the orientation of the solar PV panels from the sun. Based on typical projects and typical tolerances of solar PV mounting systems, Black & Veatch eliminated lands with slopes greater than 5 percent. These lands are shown on Figure E-6.

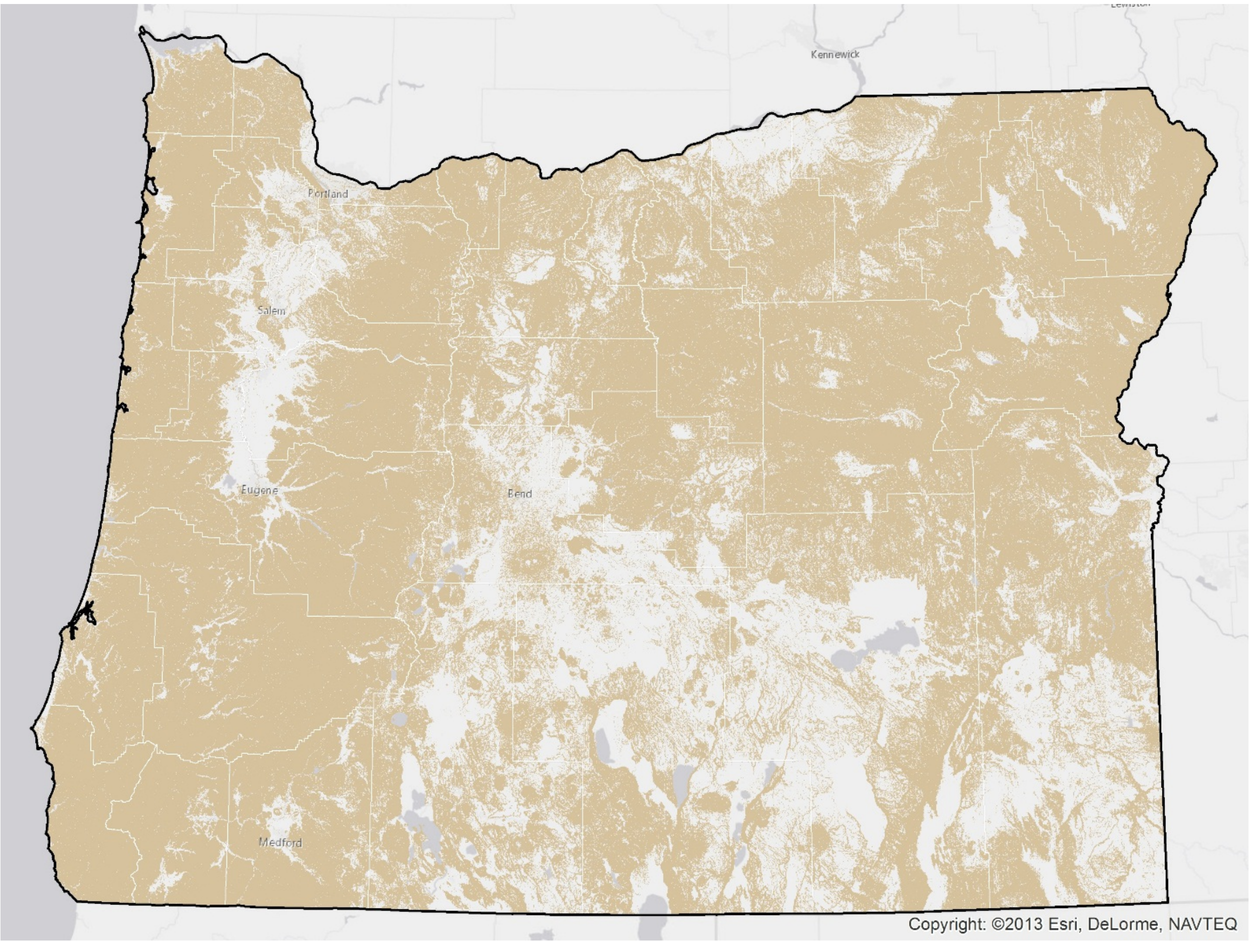


Figure E-6 Land with Slope Greater than 5 Percent

FINANCIAL SCREEN

Energy Production Model Assumptions

Table E-2 summarizes system parameters and loss assumptions made for utility-scale systems. These assumptions are largely based on typical parameters seen in the industry.

Table E-2 Utility-Scale Production Modeling Assumptions

INPUTS	ASSUMPTION	REASONING
System DC Size	Changes by customer	Technical output from GIS LiDAR analysis.
Module Type	Standard	Polycrystalline.
Inverter Loading Ratio	1.4	
Inverter Efficiency	97%	
Array Type	Fixed open rack	
Tilt	Varies by customer	Technical output from GIS LiDAR analysis.
Azimuth	Varies by customer	Technical output from GIS LiDAR analysis.
Ground Coverage Ratio	40%	
Soiling	1% for west of Cascade mountains; 5% for east of the Cascade Mountains (about 121.5 degree longitude line)	Black & Veatch ran its proprietary soiling model for a system west of the Cascade Mountains. The weather patterns west of the Cascades are fairly consistent, and therefore, Black & Veatch applied the same soiling loss to all systems west of the Cascades. Areas east of the Cascade Mountains have different weather patterns, including snowfall. Black & Veatch ran its snow model for various sites throughout eastern Oregon. Although snowfall varies by location, the variation happens during a few months that have low solar resource. Therefore, the same soiling loss estimate is applied to all systems east of the Cascades. This estimate is 5 percent annually.
Shading	Changes by customer	Assumed that the shading sources are eliminated.
Snow	0%	Accounted for in Black & Veatch's soiling loss parameter.
Mismatch	1%	
Wiring	1.5%	Black & Veatch estimates 2 percent for wiring and connection losses. This value is split between wiring and connection losses in SAM.
Connections	0.5%	See above.
Light-Induced Degradation	1.5%	Typical for polycrystalline.
Nameplate	0.5%	
Age	0.35%	Degradation seen during the first year.
Availability	99%	
Degradation	0.7%/year	

NON-SOLAR DISTRIBUTED GENERATION MARKET RESEARCH

B&V PROJECT NO. 186018
B&V FILE NO. 40.0000

PREPARED FOR

Portland General Electric

24 SEPTEMBER 2015

BLACK & VEATCH
Building a world of difference.

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1.0 Executive Summary

Black & Veatch was commissioned by Portland General Electric (PGE) to assess the potential deployment of solar and other distributed generation (DG) technologies, given technical, financial and other achievability criteria. This report examines the potential of three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines. The assessment covered various technologies within each class that are most practical for behind-the-meter, customer-sited applications for commercial customers. These technologies include the following:

1. Battery Energy Storage Systems (BESS)
    a. Lithium ion
    b. Vanadium redox flow battery
2. Fuel Cells (Natural Gas)
    a. Solid oxide fuel cells (SOFC)
    b. Molten carbonate fuel cells (MCFC)
    c. Phosphoric acid fuel cells (PAFC)
3. Microturbines (Natural Gas)

While there are other technologies that exist, they were not included because either they are not suitable for stationary applications or they are still in relatively early stages of commercialization. Black & Veatch also focused on the potential for using natural gas as the fuel input, as biogas utilization would be highly site-specific and would pose additional issues around maintenance for these technologies. Combined heat and power (CHP) applications were not included in the scope of this study, as they require customer and site specific evaluations

1.1 TECHNOLOGY CHARACTERISTICS AND COSTS

The study first considered the technical characteristics, the status of each of the technologies, and current and forecasted costs of the various technologies. A summary of the system characteristics and status of deployment for the various technologies is provided in Table 1-1 and Table 1-2. For BESS, the round trip efficiency reflects the overall efficiency losses incurred during both charging and discharging of the system.

Table 1-1 BESS Technical Characteristics

	COMMERCIAL STATUS	APPLICATION	SYSTEM SIZING (KWH)	ROUND TRIP EFFICIENCY
BESS				
Lithium Ion	Advanced	Peak Shaving/Load Shifting	5 to 32,000	75 to 90 percent
Vanadium Redox	Emerging	Peak Shaving/Load Shifting	200 to 8,000	65 to 75 percent
kWh - kilowatt-hour				

Table 1-2 Fuel Cells and Microturbines Technical Characteristics

	COMMERCIAL STATUS	APPLICATION	MINIMUM UNIT SIZE (KW)	ELECTRICAL EFFICIENCY (HHV), %
Fuel Cells				
SOFC	Emerging	Baseload	210-262.5	47 to 54
MCFC	Advanced	Baseload	300-1400	43
PAFC	Advanced	Baseload	400	42
Microturbines	Mature	Baseload/ Dispatchable (limited)	65	25
kW - kilowatt HHV - higher heating value				

As far as technical feasibility, all of these technologies have already been deployed in some capacity nationally and internationally, so they are technically feasible, and their potential are not limited by resource availability, as is the case with solar and wind resources. The greater constraints are associated with the economics of the systems.

The cost assumptions used for the various technologies are shown in Table 1-3 and Table 1-4. It should be noted that dramatic cost declines are assumed for all technologies between 2016 and 2035, except for microturbines. While there is considerable uncertainty whether these technologies can achieve those lower cost levels, Black & Veatch wanted to test whether these systems would be financially viable at those lower levels.

Table 1-3 Technical and Financial Assumptions - BESS (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)
BESS	10	1500	20	87	400	20	87
$/kW - dollars per kilowatt-hour O&M - operations and maintenance							

Table 1-4 Technical and Financial Assumptions - Fuel Cells and Microturbines (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KW)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
SOFC	210	8000	1000	7000	1500	150	5600
MCFC	300	4000	300	8000	1500	150	8000
PAFC	400	6000	150	9000	1500	150	9000
Microturbine	65	4000	170	13400	4000	170	13400
Btu/kWh - British thermal unit per kilowatt-hour							

1.2 FINANCIAL ASSESSMENT

To understand project financials, Black & Veatch modeled each of the technologies for a number of commercial customer types using a modified scripting of the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) software. The model incorporates technical performance parameters, system capital and O&M costs, project financing and taxes, incentives, and utility rate data, together with customer load data, to produce a suite of results including net present value (NPV), payback period, levelized cost of energy (LCOE), annual cash flow, and annual energy savings. Black & Veatch modeled scenarios for 2016 and 2035 for all technologies and customer types. For BESS, the system was tested with and without solar photovoltaic (PV). Also, it was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. For each customer type, each of the technologies was also sized to meet either the customer load or minimum technology unit size. For both the 2016 and 2035 cases, Black & Veatch also tested two utility rates escalating two ways: at the Consumer Price Index (CPI) of 2 percent, and at CPI plus 1 percent (CPI + 1). Additionally, fuel cells and microturbines were tested under base and low gas price scenarios.

In general, none of the BESS options evaluated are financially viable in the 2016 time frame, defined as payback of fewer than 20 years, given estimated costs, performance, available incentives, and utility rates. Aside from cost of the systems, an examination of PGE’s commercial retail rates showed that there is little or no benefit in load shifting between peak and off-peak hours, as the round-trip efficiency of BESS washes out the time of use (TOU) price differential between peak and off-peak hours. Thus, demand charge reduction is the only source of bill savings, and PGE demand charges for commercial customers are somewhat low compared to other parts of the country where BESS are being deployed. By 2035, assuming dramatic installed cost declines, BESS options do appear to become financially viable. The paybacks for the customers range from 5 to 10 years for most customers. Refer to Figure 1-1.

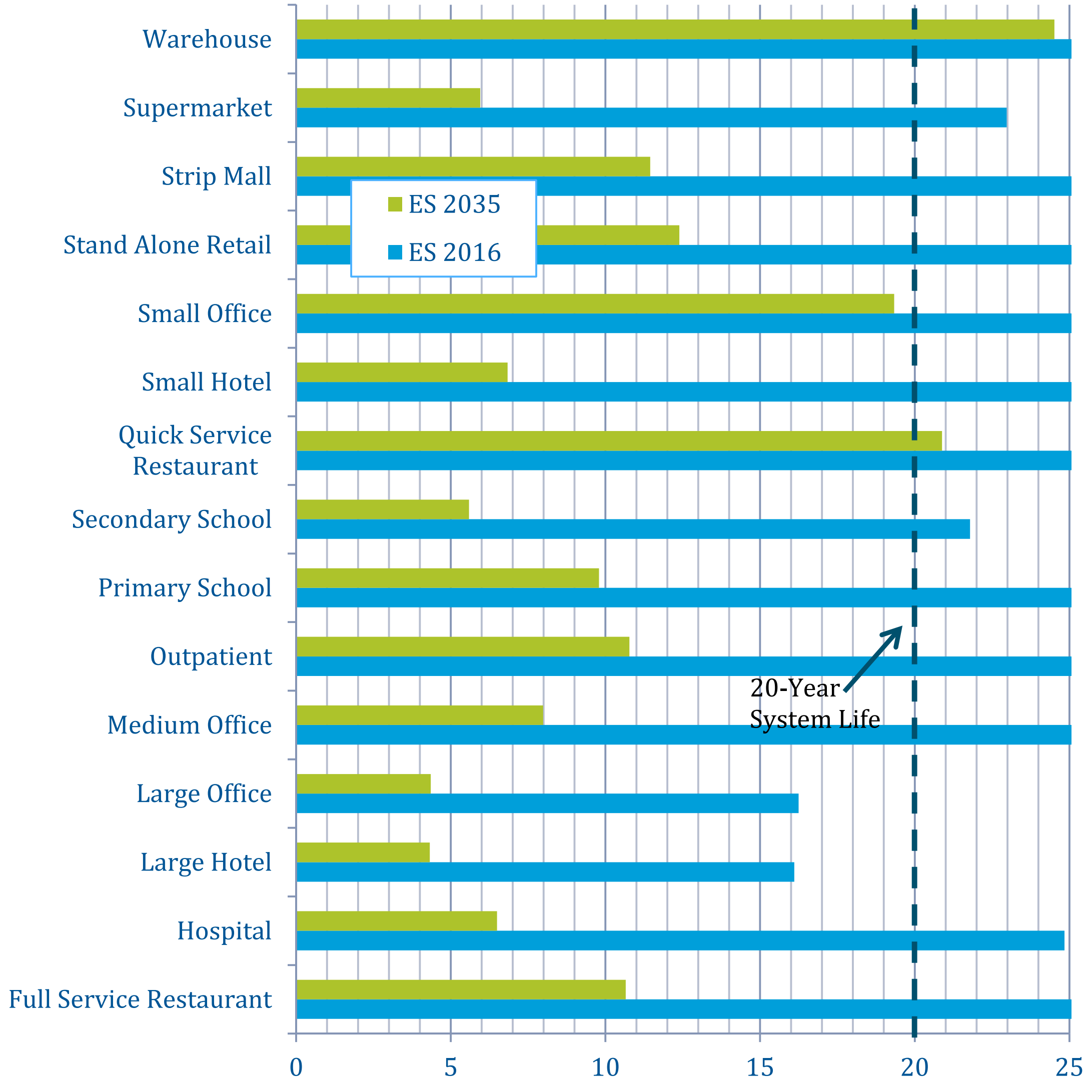

Figure 1-1 **BESS Only Payback by Customer Type**

The analysis of fuel cells and microturbines in all cases, including low natural gas price cases, showed that none of these technologies result in paybacks less than the life of the project. One exception is the case for secondary schools in 2035 deploying SOFC, under a low natural gas price scenario with rates that increase at CPI + 1, results in a payback period less than the life of the project. However, this assumes that the installed system and O&M costs drop substantially and efficiency gains are achieved for the technology, which is highly uncertain given the technology status today. Aside from capital and O&M cost, the financials of these technologies relative to utility-supplied power are penalized in two ways: higher heat rates compared to PGE's system heat rate and natural gas priced at retail rates. These drawbacks are unlikely to change under any condition. Refer to Table 1-5 for the levelized cost of energy.

Table 1-5 Summary of Levelized Cost of Energy for Fuel Cells and Microturbines (2014$/kWh)

YEAR	NATURAL GAS CASE	SOFC	MCFC	PAFC	MICROTURBINE
2016	Base	$0.24	$0.13	$0.13	$0.16
	Low	$0.23	$0.12	$0.12	$0.14
2035	Base	$0.08	$0.10	$0.11	$0.18
	Low	$0.07	$0.09	$0.10	$0.15

1.3 ACHIEVABLE POTENTIAL

Developing estimates of achievable potential for the DG technologies examined in this study is challenging in that these technologies are not financially viable in the near-term under current financial conditions, and the long-term cost outlook is quite uncertain for many of these technologies. Another added complexity is that appropriately sizing of the systems, matched to a customer's load shape, really drives the financials. In order for the technologies to be financially viable, technology costs would need to drop substantially, additional policies and incentives would need to be put in place, and changes in rate structure are needed to promote adoption. Absent those conditions, Black & Veatch forecasts minimal adoption of these technologies over the study period. If any adoption occurs, it would be towards the latter decade (2026 to 2035) of the analysis period when better clarity on costs is available. The one major caveat in this study is that Black & Veatch focused on the impact of these systems on customer electricity bills but did not account for the value of reliability and power quality to the customer. These factors are much more difficult to value and could vary widely by customer type. PGE may want to consider studying these values to customers further in future analysis.

As discussed in the financial assessment section, only BESS technology makes some financial sense by 2035. Black & Veatch estimates that during the 2025 to 2035 time frame, approximately 2.6 to 5.1 MW per year of energy storage installations may be possible if costs do fall to forecasted levels and the financially optimal system size is 10 kWh per customer. Adoption may be higher if certain customer types, such as critical facilities (hospitals, schools, etc.), place some value on reliability and power quality associated with installing BESS and, thus, install larger systems and/or have wider adoption despite poor paybacks. However, this metric was not studied in this analysis.

Table 1-6 Forecasted Annual BESS Adoption

BESS CAPACITY (MW/MWH)	2016 TO 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Adoption	0	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2
High Adoption	0	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4

For the BESS plus solar PV cases, it was determined that the addition of BESS to a solar installation does not improve the financials of the combined system, and, in fact, in the 2016 cases, BESS causes payback to increase. Therefore, in the near-term, given that solar PV installations are able to net meter, there is no incremental benefit to deploying an energy storage system with PV until net metering is no longer available. By 2035, BESS costs will have fallen enough that BESS installations, combined with solar PV, would not alter the payback significantly compared to solar PV alone. However, this also implies that a customer would be ambivalent to installing a BESS with its solar PV system, unless net metering policy changes in the future. If net metering is replaced with other policies, the deployment of BESS as part of a solar PV system may become financially viable but will depend on the rules around the alternative rate structures.

As noted previously, electricity-only applications for fuel cells and microturbines are not financially viable in almost all cases. These technologies could be configured to provide combined heat-and-power to help with the financials of the systems. While CHP may improve these technologies' financials over electricity-only operation, CHP applications are limited to specific customers that can utilize both the energy and heat. Additional studies examining specific customer load would be needed to assess the potential of fuel cells and microturbines for CHP applications.

2.0 Introduction

Black & Veatch was commissioned by Portland General Electric (PGE) to assess the potential deployment of solar and other distributed generation (DG) technologies, given technical, financial and other achievability criteria. This report examines the potential of three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines. The assessment covered various technologies within each class that are most practical for behind-the-meter, customer-sited applications for commercial customers. These technologies include the following:

1. Battery Energy Storage Systems (BESS)
    a. Lithium ion
    b. Vanadium redox flow battery
2. Fuel Cells (Natural Gas)
    a. Solid oxide fuel cells (SOFC)
    b. Molten carbonate fuel cells (MCFC)
    c. Phosphoric acid fuel cells (PAFC)
3. Microturbines (Natural Gas)

While there are other technologies that exist, they were not included because either they are not suitable for stationary applications or they are still in relatively early stages of commercialization. Black & Veatch also focused on the potential for using natural gas as the fuel input, as biogas utilization would be highly site-specific and would pose additional issues around maintenance for these technologies. Combined heat and power (CHP) applications were not included in the scope of this study, as they require customer and site specific evaluations.

3.0 Technical Characteristics and Costs

This section covers the technical characteristics of the various DG technologies that were reviewed and their typical operating modes. Current estimated costs are also presented for each of the DG technologies based on Black & Veatch's engineering, procurement, and construction (EPC) experience, industry surveys, and/or installed cost data from publicly available sources. Since many of these technologies do not have a large installed base, the number of data points may be limited.

3.1 BATTERY ENERGY STORAGE SYSTEMS

BESS are becoming a more prevalent grid resource option in recent years as the need for more flexible capacity is emerging, both at the transmission as well as the distribution level. New policies in a number of states, such as California, New York, and Hawaii, are driving growth in this sector through incentives or state requirements. Companies, such as Tesla, an electric vehicle company, are seeking ways to mass produce batteries in order to drive costs down for both transportation and stationary applications. This section covers the technical characteristics and costs associated with the BESS technologies that were reviewed, current costs, and forecasted costs.

Since the focus of this report is on behind-the-meter, stationary customer applications, lithium ion and vanadium redox flow batteries are two practical technologies to consider for stationary energy storage.

3.1.1 Technical Characteristics

Although it is not a generation resource, energy storage can perform many of the same applications as a traditional generator by using stored energy from the grid or from other distributed generation resources. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable integration applications. A snapshot of various energy storage applications across the electric utility system can be found on Figure 3-1.

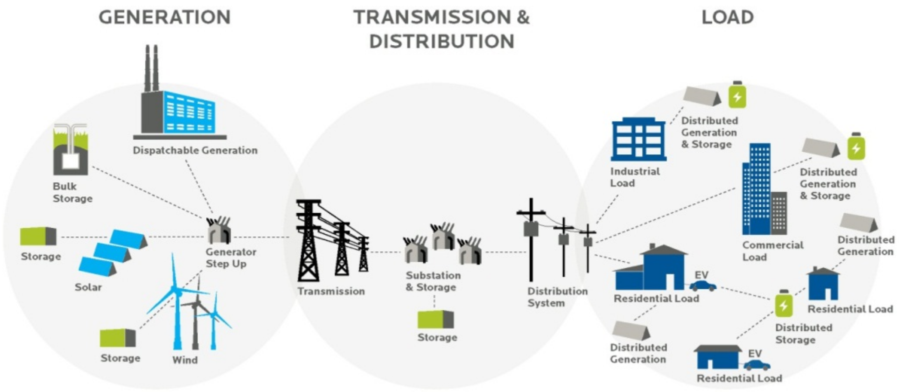

Figure 3-1 Energy Storage Applications Across the Electric Utility System

Generally speaking, energy storage can serve a number of roles:

- **Time of Use (TOU) Energy Management (Electrical Energy Time-Shift):** Energy storage can charge energy when electricity prices are low and discharge to supply load when electricity prices are high.
- **Demand Charge Management:** Energy storage can discharge during expensive peak demand times to reduce a customer's monthly demand charges.
- **Electric Service Reliability:** Energy storage can improve the reliability of a customer's electric service and help reduce the number of outages for customers. This application can include emergency backup power.
- **Power Quality:** Energy storage can protect loads against short duration events (i.e., voltage flickers, frequency deviations) that affect the quality of power delivered to the load.
- **Frequency Regulation:** Energy storage can be used to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- **Voltage Support:** The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- **Variable Energy Resource Capacity Firming:** Energy storage can be used to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- **Variable Energy Resource Ramp Rate Control:** Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.

Energy storage applications can be grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to 1 hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control/smoothing are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems.

For the purposes of this report, Black & Veatch focused on customer-sited storage that is connected behind the electricity meter for commercial and industrial customers (also called behind-the-meter energy storage). The applications specifically related to behind-the-meter energy storage are a subset of all the potential applications storage systems can perform.

The primary purpose of the energy storage devices considered in this report would be to provide TOU energy management and demand charge management, which would be primarily an energy application. TOU energy management and demand charge management together can be called end-user bill management applications. While the storage systems are versatile and can perform other applications, the end-user bill management applications are the most common applications performed by behind-the-meter energy storage systems seen today. This is because avoiding expensive demand charges (that can vary by region and utility) can provide reasonable value to the customer. More detailed analysis on end-user bill management can be found in later sections of this report. The other applications can be performed by behind-the-meter energy storage, but often valuing these particular applications is difficult and is highly site and market-specific.

A fully operational BESS comprises an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a battery management system (BMS) and site or BESS controller (Table 3-1).

Table 3-1 BESS Components

COMPONENT	DEFINITION
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components, and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bidirectional converter that converts alternating current (ac) to direct current (dc) and dc to ac. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be composed of various BMS units at the cell, module, and system level. The BMS monitors and manages the battery state of change (SOC) and charge and discharge of the ESS.
BESS/Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS/site controller.

When considering different energy storage technologies, there are a number of key performance parameters to understand:

- **Power Rating:** The rated power output (MW) of the entire energy storage system.
- **Energy Rating:** The energy storage capacity (MWh) of the entire energy storage system.
- **Discharge Duration:** The typical duration that the BESS can discharge at its power rating.
- **Response Time:** How quickly an ESS can reach its power rating (typically in milliseconds).
- **Charge/Discharge Rate (C-rate):** A measure of the rate at which the ESS can charge/discharge relative to the rate at which it will completely charge/discharge the battery in 1 hour. A 1 hour charge/discharge rate is a 1C rate. Furthermore, a 2C rate completely charges/discharges the ESS in 30 minutes.
- **Round Trip Efficiency (RTE):** The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS, and transformer efficiencies.
- **Depth of Discharge (DoD):** The amount of energy discharged as a percentage of its overall energy rating.
- **State of Charge (SOC):** The amount of energy an energy storage resource has charged relative to its energy rating, noted as a percentage.
- **Cycle Life:** These are reported at 80 percent and 10 percent of DoD and correlate to the number of cycles the ESS can undergo before the energy storage system degrades to 80 percent of its initial energy rating (kWh). The cycle life can vary for various DoDs.

Since the focus of this report is on behind-the-meter, stationary customer applications, lithium ion and vanadium redox flow batteries are two practical technologies to consider for stationary energy storage. Most of the stationary energy storage activity in the industry is currently based on the lithium ion battery technology. Lithium ion batteries are the dominant player in battery energy storage, and their demonstrated experience is growing. According to the Department of Energy (DOE) Global Energy Storage Database, over 80 MW of lithium ion installations are operational in the United States. Lithium ion batteries are projected to be a major industry player in the years to come and are well suited for both power and cycling applications as well as some energy applications.

Vanadium redox flow battery installations are more limited, but worldwide installations total over 17 MW, including installations currently being verified.[1] Vanadium redox flow batteries are also projected to likely have a considerable market share for large stationary applications in the future and are best suited for energy applications that require longer durations of discharge.

A basic description of these two technologies is provided in the following sections.

3.1.1.1 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode. Some examples of cathode and anode combinations are shown on Figure 3-2.

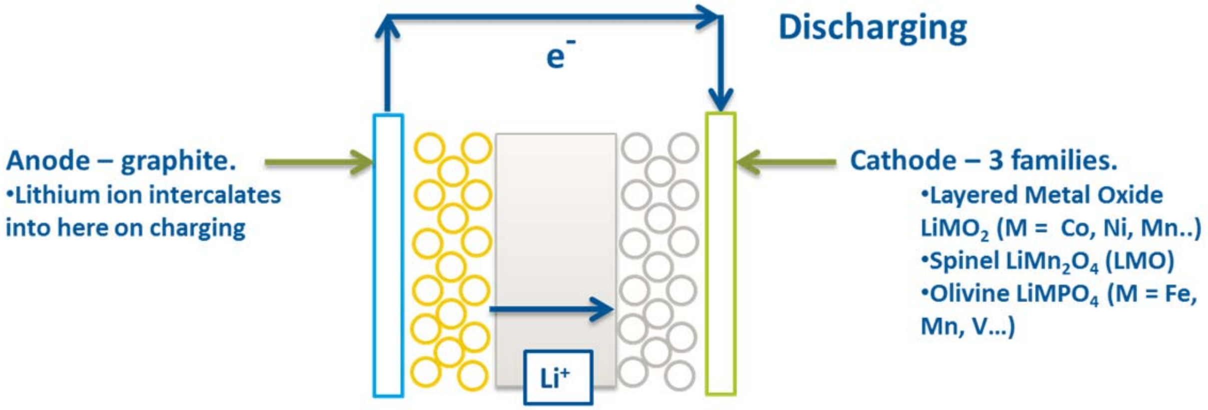

Figure 3-2 **Lithium Ion Battery Showing Different Electrode Configurations**

The battery cells are integrated to produce modules. These modules are then strung together in series/parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

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[1] DOE Global Energy Storage Database, http://www.energystorageexchange.org/.

An image of an example lithium ion BESS can be found on Figure 3-3.

Figure 3-3 Lithium Ion Battery Energy Storage System Located at Black & Veatch HQ

Lithium ion battery storage systems can be used for both power and energy applications. One key strength of lithium ion batteries is their strong cycle life (refer to Table 3-2). For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate excellent cycle-life characteristics. Additionally, lithium ion systems demonstrate good cycle-life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- **Excellent Cycle Life**: Lithium ion technologies have a cycling ability superior to other battery technologies such as lead acid.
- **Fast Response Time**: Lithium ion technologies have a fast response time that is typically less than 100 milliseconds.
- **High Round Trip Efficiency**: Lithium ion energy conversion is efficient and has up to a 90 percent round trip efficiency (dc-dc).
- **Versatility**: Lithium ion solutions can provide many relevant operating functions.
- **Commercial Availability**: There are dozens of lithium ion battery manufacturers.
- **Energy Density**: Lithium ion solutions have a high energy density to meet space constraints.

Table 3-2 Typical Lithium Ion Battery Performance Parameters

PARAMETER	LITHIUM ION BATTERY
Power rating, MW	0.005 to 32
Energy rating, MWh	0.005 to 32
Discharge duration, hours	0.25 to 4
Response time, milliseconds	< 100
Round trip efficiency (ac-ac), %	75 to 90
Cycle life, cycles at 80 % DoD	1,200 to 4,000
Cycle life, cycles at 10 % DoD	60,000 to 200,000

3.1.1.2 Vanadium Redox Flow Batteries

Vanadium redox flow batteries are another form of electrochemical storage. Vanadium redox flow batteries are the most commercially developed technology of the various flow battery technologies. In this technology, the energy for these systems is stored within a liquid electrolyte that is typically stored in large tanks. The electrolyte can be scaled to produce the desired energy storage capacity; the power cells (where the reactions happen) can be scaled to produce the desired power output. A diagram of a vanadium redox flow battery can be found on Figure 3-4.

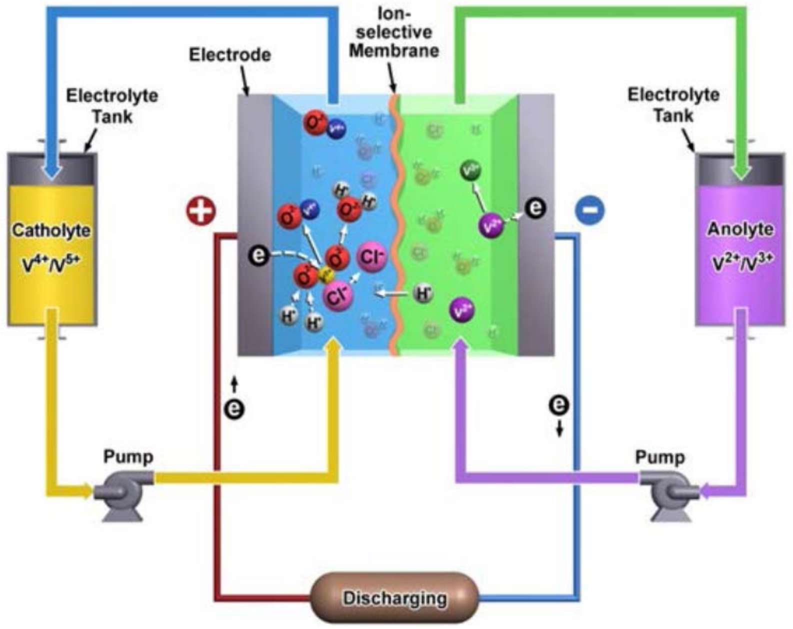

Figure 3-4 Diagram of Vanadium Redox Flow Battery (Source: DOE/Electric Power Research Institute [EPRI] 2013 Electricity Storage Handbook in Collaboration with National Rural Electric Cooperative Association [NRECA])

This technology is also integrated with a PCS to form the overall BESS. Vanadium redox batteries are more typically used for energy applications, as they can more effectively be scaled to longer discharge periods than lithium ion batteries. However, one drawback with flow batteries is the space requirements for these systems. The vanadium redox flow batteries require more space for the installation than lithium ion batteries. Vanadium redox BESS can be modular, as shown on Figure 3-5, and containerized systems, as shown on Figure 3-6.

Figure 3-5 Vanadium Redox Flow Battery (Source: Prudent Energy brochure)

Figure 3-6 Containerized Flow Battery (Source: UniEnergy)

A comparison of lithium ion and flow battery technologies is provided in Table 3-3. Compared to lithium ion batteries, flow batteries are better suited to providing longer discharge durations and have a longer cycle life at 80 percent of DoD. On the other hand, vanadium redox flow batteries suffer from lower round trip efficiencies. Additionally, flow batteries do not perform as well at shallow 10 percent DoD cycles. While the electrolyte in flow batteries does not degrade, manufacturer information indicates that the power cell component of the battery may need to be replaced after 5 to 10 years.

Table 3-3 Vanadium Redox Flow Battery Versus Lithium Ion Battery

PARAMETER	LITHIUM ION BATTERY	VANADIUM REDOX FLOW BATTERY
Power rating, MW	0.005 to 32	0.050 to 4
Energy rating, MWh	0.005 to 32	0.200 to 8
Discharge duration, hours	0.25 to 4	3 to 8
Response time, milliseconds	< 100	< 100
Round trip efficiency, %	75 to 90	65 to 75
Cycle life, cycles at 80 % DoD	1,200 to 4,000	10,000 to 15,000 (not DoD dependent)
Cycle life, cycles at 10% DoD	60,000 to 200,000	10,000 to 15,000 (not DoD dependent)

3.1.2 BESS Costs

Black & Veatch leveraged its experience in the energy storage industry and deep vendor knowledge to provide high-level costs for the two technologies of interest.

In addition to this, Black & Veatch reviewed Sandia National Laboratory's report titled "DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA," which includes costs gathered through extensive surveys of a number of vendors.[2] Black & Veatch also reviewed the DOE Global Energy Storage Database, which is a compilation of many existing energy storage projects.[3] Furthermore, historical data from the California Self-Generation Incentive Program (SGIP) was also reviewed. SGIP program data show costs have declined significantly since 2009-2010 but have been generally flat between 2011 and 2014 (Figure 3-7).

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[2] DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA, http://www.sandia.gov/ess/handbook.php.

[3] DOE Global Energy Storage Database, http://www.energystorageexchange.org/.

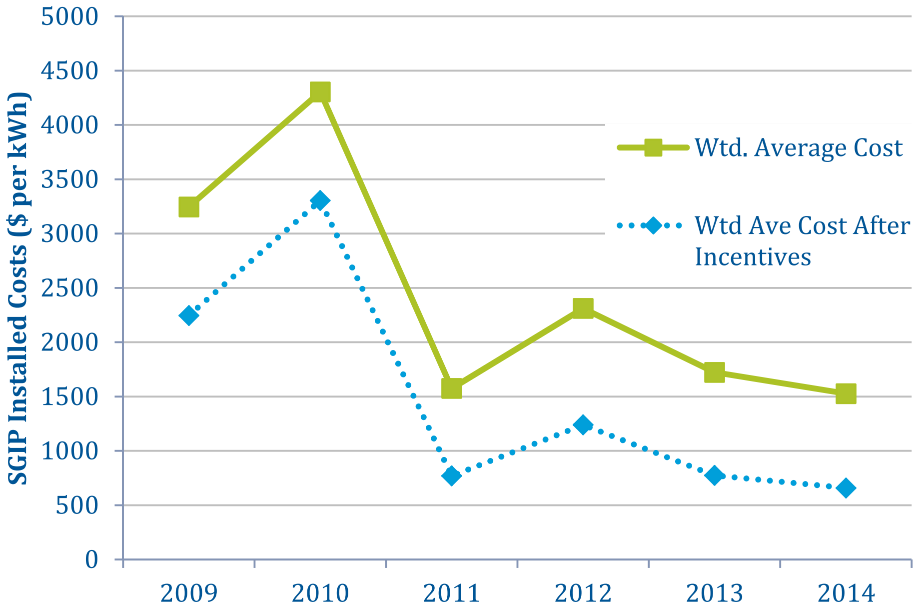

Figure 3-7 California SGIP Historical Energy Storage Costs ($ per kWh) (Source: SGIP Database)

3.1.2.1 Current Energy Storage Costs

Reported costs of energy storage systems can vary widely, depending on size and unique site conditions, and are often reported inconsistently. Costs may be reported for the batteries alone or for total installed cost. Furthermore, installed costs for BESS may be reported in cost per kW (power) or cost per kWh (energy). Since the applications considered in this analysis are primarily energy applications, costs are presented on a dollars per kWh basis.

Current reported equipment pricing for lithium ion batteries alone range from $500 to $750 per kWh and total installed costs ranging from $700 to $3000 per kWh, with smaller behind-the-meter systems at the higher end.[4] Vanadium redox flow batteries are far more integrated systems, so costs are typically reported as total installed cost.

Black & Veatch developed a range of installed costs that include the following components:

- Battery modules.
- PCS.
- BMS.
- Controller.

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[4] "The Value of Distributed Electricity Storage in Texas," Brattle Group, 2014. http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708.

- Balance-of-systems, including interconnecting electrical equipment, racking, and wiring.
- Engineering and design, including necessary permitting and construction management.
- Installation, including labor.
- Contractor margin.

Various sizes of energy storage systems are shown in Table 3-4 that represent a reasonable range of sizes for the storage systems studied in this report. The costs are presented in terms of dollars per installed kWh based on the energy storage ability, which is what will be used in the modeling exercise presented later in this study.

Table 3-4 Energy Storage System Conceptual EPC Costs for 2015 (2014$)

TECHNOLOGY	POWER, KW	ENERGY, KWH	INSTALLED COST, $/KWH	FIXED O&M, $/KW-YR	VARIABLE O&M, $/KWH
Lithium ion battery	5	10	1,500 – 2,000	20-25	0.0010 – 0.0015
	100	400	1,250 – 1,750	20 –25	0.0010 – 0.0015
	1,000	4,000	1,000 – 1,300	8 –10	0.0010 – 0.0015
Vanadium redox flow battery	200	700	1,400 – 1,600	15-20	0.0015 – 0.0020
	1,200	4,000	900 – 1,100	7-9	0.0015 – 0.0020

Fixed and variable operations and maintenance (O&M) costs for lithium ion and flow batteries are also presented in Table 3-4. Fixed O&M includes routine maintenance on the equipment and electronics, and variable O&M depends on how much the storage system is used throughout the course of its operation. Since the O&M is dependent on the expected operation, the operation of these systems is assumed to be one full charge and discharge daily for 365 days of the year. This is a reasonable assumption for the expected applications considered in this report. The O&M costs do not include battery replacements or component replacements over time. Furthermore, the number of cycles in operation will determine their overall life, which is estimated to be approximately 10 years if cycled daily, and proportionately longer if the system is not cycled daily.

3.1.2.2 Forecasted Energy Storage Costs

Based on industry workshops, the DOE has established goals of reducing the installed system capital cost for BESS in the near-term (by 2019) to $250 per kWh. [5] Additionally, the DOE has a longer term 2024 goal of $150 per kWh. Other industry reports project battery-alone costs to drop to $100 to $250 per kWh in the near-term (5 to 10 years) and total installed costs to be as low as $350 per kWh by 2020, which is more reasonable than the DOE goals. In all cases, these costs are for larger utility-scale installations.

For smaller-scale systems being considered for behind-the-meter applications, Black & Veatch believes these targets are overly optimistic for complete BESS installations. Therefore, for the

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[5] Grid Energy Storage, U.S. Department of Energy, December 2013 (http://energy.gov/oe/downloads/grid-energy-storage-december-2013).

10 year horizon, Black & Veatch expects a total installed cost to be more in the range of $400 to $500 per kWh in 2014$ and then costs to decline more slowly beyond that time frame.

3.2 FUEL CELLS

Fuel cells convert hydrogen directly to electricity through an electrochemical reaction, as shown on Figure 3-8. Hydrogen-rich fuels such as natural gas or digester gas may be transformed into hydrogen in a process called reforming prior to use in certain types of fuel cells. Fuel cell technologies have a number of operational advantages including relatively high conversion efficiency (i.e., greater than 40 percent), low emissions, and quiet operation. Utilization of heat recovery for combined heat and power operations can increase the overall efficiency to more than 80 percent. However, fuel cells currently suffer from a number of shortcomings including high capital cost, short fuel cell stack life of 3 to 5 years (which increases O&M costs), and corrosion and breakdown of cell components, resulting in performance degradation over time. Due to the long startup times for fuel cells, they also operate mostly as baseload generation and cannot be dispatched to follow load.

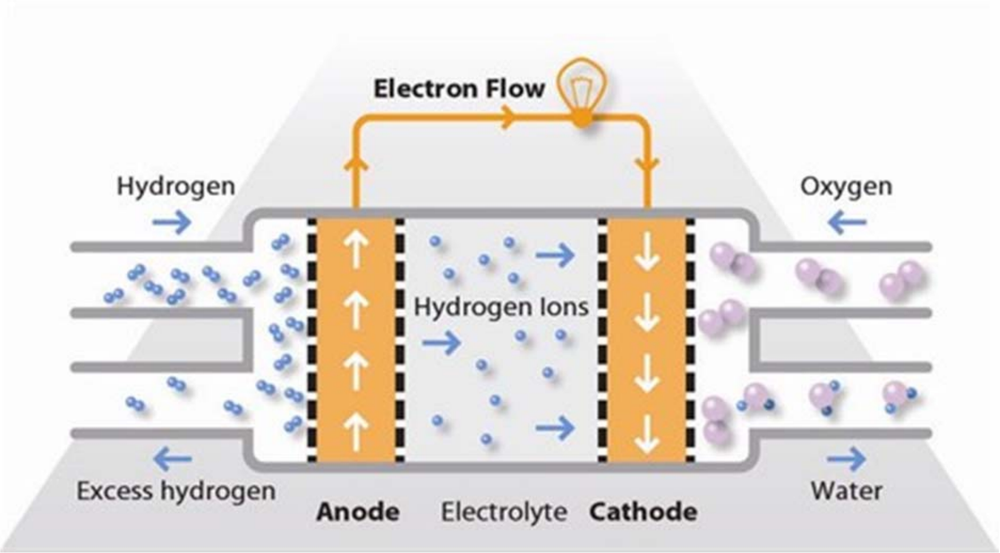

Figure 3-8 Schematic of a Hydrogen-Fueled Fuel Cell (Source: www.fuelcelltoday.com)

The discussion in this section focuses on stationary fuel cells for electricity-only applications. The technologies that are reviewed include:

- SOFC
- MCFC
- PAFC

Only a handful of manufacturers supply these technologies, so the key suppliers are discussed in this section. It is important to note that none of the fuel cell suppliers are profitable today, and as will be shown in the cost discussion, fuel cell costs have not shown any decline in the past 10 years.

3.2.1 Technical Characteristics

Fuel cells are composed of two electrodes separated by an electrolyte. The specific reactions that occur at the electrode depend on the type of electrolyte employed within the fuel cell. However, in general, ions are created at either the anode or cathode, then pass through the electrolyte; simultaneously, electrons flow between the electrodes through an external circuit, producing an electrical current. Catalysts are often employed to speed up the reactions at the electrodes.

There are six prominent types of fuel cells, typically distinguished by the material that serves as the electrolyte within the fuel cell:

- SOFC
- MCFC
- PAFC
- Proton exchange membrane fuel cells (PEMFC)
- Direct methanol fuel cells (DMFC)
- Alkaline fuel cells (AFC)

Distinguishing features for these technologies are listed in Table 3-5.

Table 3-5 Distinguishing Features of Fuel Cell Technologies

FUEL CELL TECHNOLOGY	ELECTROLYTE	ELECTRODE CATALYST	MOBILE ION	OPERATING TEMPERATURE (°C)	POTENTIAL FUELS
PEMFC	Water-based, acidic polymer membrane	Platinum	H+	< 100	Hydrogen
DMFC	Polymer membrane	Platinum-Ruthenium	H+	60 to 130	Methanol
AFC	Potassium hydroxide in water	Nickel	OH-	70 to 100	Hydrogen
PAFC	Phosphoric acid in silicon carbide structure	Platinum	H+	180	Hydrogen
MCFC	Liquid carbonate salt suspended in porous ceramic	None	CO32-	650	Hydrogen, natural gas, biogas
SOFC	Solid ceramic (e.g., zirconium oxide/ yttrium oxide)	None	O2-	800 to 1,000	Hydrogen, natural gas, biogas

Source: Fuel Cell Today (www.fuelcelltoday.com).

As shown in Table 3-5, PEMFC and DMFC technologies are typically employed for portable and transportation applications, while MCFC, PAFC, and SOFC technologies are employed for behind-the-meter, stationary power generation applications. While there are some cases of PEMFC used in stationary applications, the technology requires very pure hydrogen to minimize contamination, which would be challenging for customer-sited projects. Therefore, in the remainder of this discussion regarding fuel cells, Black & Veatch has focused on MCFC, PAFC, and SOFC technologies. Note that MCFC and SOFC technologies are also more practical for stationary applications because they are able to use natural gas directly as the input fuel, rather than hydrogen.

Table 3-6 Typical Applications for Fuel Cells

	PORTABLE APPLICATIONS	STATIONARY APPLICATIONS	TRANSPORTATION APPLICATIONS
Typical Power Range, kW	0.005 to 20	0.5 to 400	1 to 100
Potential Fuel Cell Technology	PEMFC DMFC	MCFC PAFC SOFC	PEMFC DMFC
Examples	Personal electronics; military applications	Power generation; uninterrupted power supplies (UPS)	Material handling vehicles; automobiles, trucks, and buses

Source: Fuel Cell Today, Fuel Cell Industry Review 2013.

Hydrogen-rich fuels such as natural gas or digester gas may be transformed into hydrogen in a process called reforming. A common method of reforming introduces steam to the fuel stream; the chemical formula of this reforming reaction for natural gas composed primarily of methane (CH_4) is as follows:

$$CH_4 + 2\ H_2O \Rightarrow CO_2 + 4\ H_2$$

MCFC and SOFC technologies operate at high temperatures (650 °C and higher) and, therefore, are able to reform gaseous fuels internally. Lower temperature fuel cells, such as PAFC, require an external reformer, which adds to the system cost. When fuel gases (e.g., natural gas or digester gas) are used, certain constituents in the fuel gas (e.g., moisture, hydrogen sulfide (H_2S), and siloxanes) must be removed before the gas is used in fuel cells to avoid damage to internal components of the fuel cells.

After reforming, hydrogen is supplied to the fuel cell stack. A “stack” is a group of fuel cells (each consisting of an anode and a cathode separated by an ion-conducting electrolyte) that are connected in series within the fuel cell module. The number of fuel cells in the stack determines the total voltage, and the surface area of each cell determines the total current. Multiplying the voltage by the current yields the total electrical power generated. The electricity produced is in the form of dc, which is converted to ac by an inverter.

This overall process, including the reformation of natural gas and generation of electricity, is illustrated on Figure 3-9.

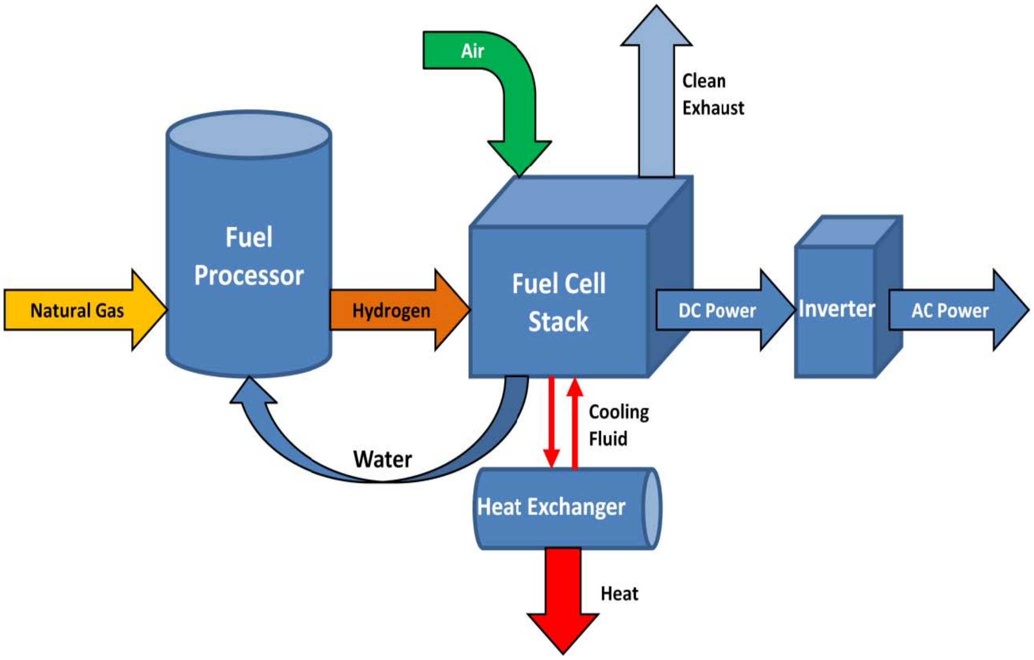

Figure 3-9 Fuel Cell Flow Diagram

Operational advantages of fuel cell technologies include high efficiency (i.e., greater than 40 percent), low emissions, and quiet operation. The higher efficiencies are achievable because the fuel cell process does not involve combustion and is, therefore, not limited by Carnot cycle efficiency. In addition, fuel cells can sustain high efficiency operations even under partial load conditions (generally constant above 60 percent of maximum load). Utilization of heat recovery for combined heat and power (CHP) operations can increase the overall efficiency to more than 80 percent. As a result of these high operating efficiencies and the lack of combustion, fuel cells emit fewer greenhouse gases per unit of power generated than other DG technologies such as internal combustion engines and microturbines. The combustion-free process also produces fewer byproducts than the other alternatives, which reduces criteria air pollutant emissions (notably nitrogen oxides [NO_x] and sulfur oxides [SO_x]).

Disadvantages of fuel cells vary by type. High capital cost, long startup time, a short fuel cell stack life of 3 to 5 years (which increases O&M costs), low power density, and performance degradation over time resulting from corrosion and breakdown of cell components are the primary disadvantages of fuel cell systems and are the focus of research and development.

Depending on the type of fuel cell employed and the nature of the fuel gas, fuel cells require maintenance, including the following:

- Replacing the contaminant adsorbents in the pretreatment module two to four times annually.
- Conducting an annual shutdown for replacement of filters and for servicing other components such as blowers.
- Replacing fuel cell stacks every 3 to 10 years, depending on the type.
- Overhauling the fuel processor after 5 to 10 years of use.

3.2.1.1 Solid Oxide

SOFC utilize a solid, nonporous ceramic metal oxide electrolyte, typically Yttria Stabilized Zirconia (YSZ). SOFC operate at relatively high temperatures (500 to 1000 °C) and can achieve electrical efficiencies in the range of 60 percent. When used on larger scales, the expelled heat can be utilized to generate additional energy. The resulting CHP efficiency may be between 70 and 80 percent.

The higher operating temperatures allow for internal reforming of a wide range of fuels, including natural gas and other hydrocarbon renewable and fossil fuels, without the use of a reforming catalyst. The absence of a catalyst eliminates the need for precious metals (such as platinum group metals) in their construction. Conversely, the higher operating temperatures present engineering and design challenges. To date, SOFC operational life is usually limited to approximately 25,000 hours because of durability issues associated with the material tolerances to temperature, particularly when used in a cyclical application. Because of the shorter life span, cell replacement is necessary on a more frequent basis and O&M costs associated with SOFC are estimated to be high, approximately $1000/kW-yr, based on reported extended warranty costs.[6]

Current SOFC development efforts are focused on reducing operating temperatures through the use of a different or improved electrolyte and electrodes, while maintaining high efficiency. Lower operating temperatures should provide extended operational life and allow the use of less expensive materials in the stack construction and electrical interconnections. Such achievements could effectively reduce both capital and O&M costs.

SOFC Technology Supplier: Bloom Energy

Bloom Energy, based in Sunnyvale, California, provides modular SOFC systems for electricity-only applications. The company was founded in 2001, growing from the work of company founder Dr. K.R. Sridhar for the National Aeronautics and Space Administration (NASA) Mars program. Bloom acknowledges the challenges associated with SOFC and claims to have solved those challenges with breakthroughs in material science and system design. Bloom Energy's products are named "Energy Servers" and are available at nameplate capacities of 210 and 262.5 kW (models ES-5700 and ES-5710, respectively).

Under California's SGIP program, Bloom systems have accounted for over 100 MW of capacity in the state since 2007, with individual systems ranging in size from 210 kW to 4.2 MW. Bloom has supplied its systems to several Fortune 500 companies, banks, and data centers. In July 2014

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[6] GreenTech Media, "Stat of the Day: Fuel Cell Costs From Bloom and UTC" May 13, 2013. Available online at: http://www.greentechmedia.com/articles/read/Stat-of-the-Day-Fuel-Cell-Costs-From-Bloom-and-UTC.

Bloom partnered with Excelon to develop 21 MW of fuel cell projects to supply power to customers throughout the United States.

Performance characteristics of the Bloom Energy Servers are shown in Table 3-7.

Table 3-7 Performance Characteristics of Bloom Energy Fuel Cell Systems

	BLOOM ENERGY: ES-5700	BLOOM ENERGY: ES-5710
Unit Ratings		
Gross Power Output, kW	210	262.5
Output Voltage, V	480	480
Operating Parameters		
System Efficiency$^{(1)}$		
Heat Rate (HHV), Btu/kWh	6,925-7,990	6,925-7,990
Electrical Efficiency (HHV net AC), %	47-54	47-54
Emission Rates		
Carbon Dioxide, lb/MWh	735-849	735-849
Nitrogen Oxides, lb/MWh	<0.01	<0.01
Sulfur Oxides, lb/MWh	Negligible	Negligible
Volatile Organic Compounds (VOCs)	<0.02	<0.02
Carbon Monoxide, lb/MWh	<0.10	<0.10
Particulate Matter (PM_{10}), lb/MWh	NA	NA

Source: Bloom Energy
Notes:
1. Heat rate and electrical efficiency are estimated over project life.

3.2.1.2 Molten Carbonate

MCFC operate at temperatures near 650 °C, providing balance between the electrolyte conductivity and a temperature range suitable for lower cost metals. The electrolyte in an MCFC is a molten carbonate salt mixture, suspended in a porous ceramic. The higher operating temperatures allow for internal reforming of a range of fuels, including natural gas and coal syngas. MCFC achieve electrical efficiencies in the range of 45 to 50 percent. Often, MCFCs are deployed in CHP applications, where even further energy recovery from the system is accomplished, achieving upwards of 85 percent overall energy efficiency. Modern commercial MCFC stacks have life spans estimated around 40,000 hours, with O&M costs of approximately $300/kW-yr.

The use of nonprecious metals and the ability to internally reform the fuel both reduce the cost of MCFC. While MCFC run cooler than SOFC, the high operating temperatures still lead to some durability challenges and reduced operating life span. In the case of the MCFC, the corrosive property of the electrolyte has been seen to further decrease cell life. Current research and development (R&D) efforts in the field of MCFC are focused on increased cell and stack life through electrolyte advances and the use of more robust electrode materials.

MCFC Technology Supplier: FuelCell Energy

FuelCell Energy, originally founded in 1969 as Energy Research Corporation, has been producing MCFC since the 1980s, with the first commercial plant installed in 2003 utilizing its 250 kW stack. The company's production facility is located in Torrington, Connecticut, and, as of 2012, it produces 56 MW of MCFC annually. In 2013, the company installed a 59 MW facility in South Korea, currently the largest fuel cell plant in the world. According to the company's website, FuelCell Energy has "more than 300 MW of power generation capacity installed or in backlog," and the company's power generation facilities have generated more than 2.5 billion kilowatt-hours of electricity.

FuelCell Energy provides three products in its Direct FuelCell (DFC) line: the 2.8 MW DFC3000, the 1.4 MW DFC1500, and the 300 kW DFC300. The company also provides its "Multi-MW DFC-ERG" (Direct FuelCell Energy Recovery Generation) system, which couples a gas expansion turbine utilizing the natural gas pipeline pressure to drive the turbine prior to supplying the fuel cells. In this configuration, the system increases its electrical efficiency from 43 percent (HHV, DFC3000 and DFC1500) to 55 percent or higher.

Performance characteristics of FuelCell Energy systems are listed in Table 3-8.

3.2.1.3 Phosphoric Acid (PAFC)

PAFC is a long-established fuel cell technology with many years of development and operational history. This type of fuel cell utilizes a liquid phosphoric acid electrolyte and carbon paper anodes with a platinum-based catalyst. PAFC have an electrical efficiency of 40 to 50 percent, though they are typically utilized in CHP applications, accomplishing a combined electrical and thermal efficiency as high as 80 to 90 percent. Due to relatively low operating temperatures, around 200 °C, cell corrosion and degradation is limited, and PAFC have demonstrated long operating life spans as high as 80,000 hours. However, the use of expensive catalyst material and stack design results in a relatively high cost for this technology.

Current PAFC development efforts are focused on increased catalyst performance and lower cost materials. Both of these goals would lead to lower costs on a $/kW basis for PAFC systems. Currently, commercial PAFC systems operate on lifespans around 60,000 hours. Due to the longer stack life compared to MCFC and SOFC, O&M costs for commercial PAFC systems are estimated to be approximately $150/kW-yr.

PAFC Technology Supplier: Doosan Fuel Cell America, Inc.

Doosan Fuel Cell, based in South Windsor, Connecticut, is a well-established commercial provider of PAFC systems. Doosan acquired ClearEdge Power, after it filed for bankruptcy, and its PureCell fuel cell in July 2014. Prior to that, ClearEdge had purchased UTC Power in 2013; UTC was originally founded in 1958 and provided fuel cells to early NASA missions.

Table 3-8 Performance Characteristics of FuelCell Energy Fuel Cell Systems

	FUELCELL ENERGY: DFC3000	**FUELCELL ENERGY: DFC1500**
Unit Ratings		
Gross Power Output, kW	300	1,400
Output Voltage, V	480	480
Operating Parameters		
Fuel and Water Consumption/Discharge		
Natural Gas Consumption, scfm	39	181
Natural Gas Consumption(1), MMBtu/h (HHV)	2.39	11.1
Water Consumption (average), gpm	0.9	4.5
Water Discharge (average), gpm	0.45	2.25
System Efficiency(2)		
Heat Rate (HHV), Btu/kWh	7,950	7,950
Electrical Efficiency, %	43	43
Emission Rates		
Carbon Dioxide (electricity only), lb/MWh	980	980
Nitrogen Oxides, lb/MWh	0.01	0.01
Sulfur Oxides, lb/MWh	0.001	0.0001
Particulate Matter (PM_{10}), lb/MWh	0.00002	0.00002

Source: FuelCell Energy

Notes:

1. Assumes HHV of natural gas of 1,023 British thermal unit per standard cubic foot (Btu/scf).
2. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).

scmf - standard cubic feet per minute
MMBtu/h - million British thermal units per hour
gpm - gallons per minute

The PureCell Model 400 is a 400 kW PAFC system consisting of a fuel reformer, the PAFC stack, and a power conditioner to supply AC power. Process heat is also available and, when combined with electricity generation, the PureCell achieves an overall efficiency of 90 percent. The PureCell is marketed toward and utilized primarily in CHP applications to maximize the system's total energy product. Doosan states that the PureCell product line has over 11 million fleet operating hours, with the Model 400 (introduced in 2012) recently surpassing 1 million fleet operating hours.

Performance characteristics of the PureCell are shown in Table 3-9.

Table 3-9 Performance Characteristics of Doosan PureCell Model 400

	PURECELL MODEL 400
Unit Ratings	
Gross Power Output, kW	400
Output Voltage, V	480
Operating Parameters(1)	
Fuel and Water Consumption/Discharge	
Natural Gas Consumption, scfm	58.6
Natural Gas Consumption, MMBtu/h (HHV)	3.6
Water Consumption (average), gpm	None
Water Discharge (average), gpm	None
System Efficiency(2,3)	
Heat Rate (HHV), Btu/kWh	9,000
Electrical Efficiency, %	42
Emission Rates(4)	
Carbon Dioxide (electricity only), lb/MWh	1,049
Nitrogen Oxides, lb/MWh	0.01
Sulfur Oxides, lb/MWh	Negligible
Particulate Matter (PM_{10}), lb/MWh	Negligible

Source: Doosan Fuel Cell

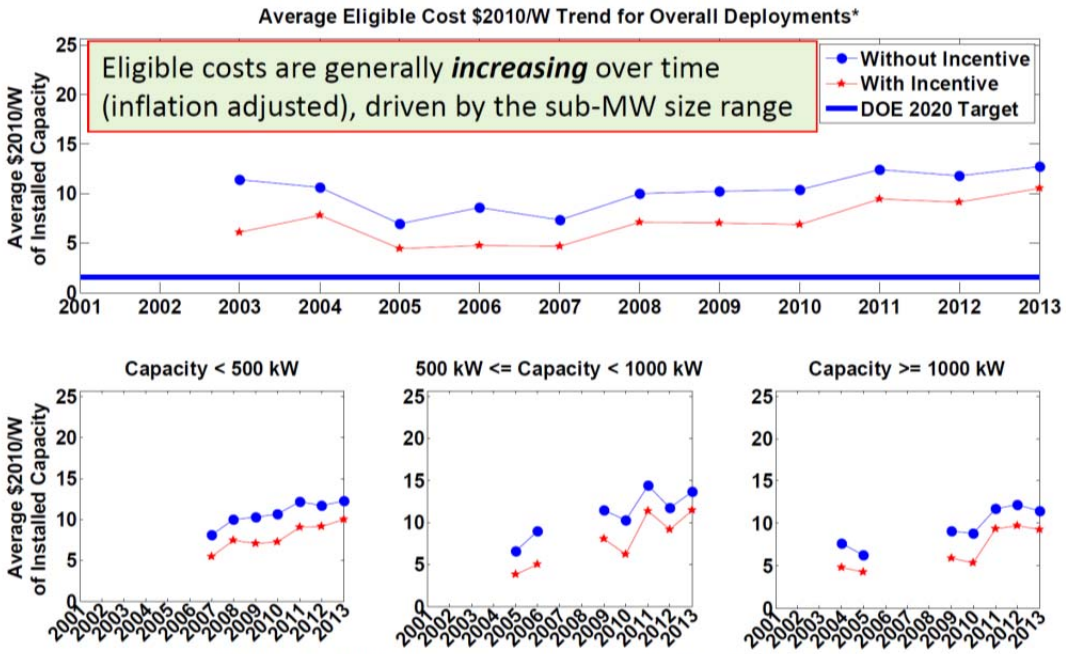
Notes:

1. Average performance during first year of operation.
2. Assumes HHV of natural gas of 1,025 Btu/scf.
3. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).
4. Performance and emissions based on 400 kW operation.

3.2.2 Fuel Cell Costs

Upon reviewing various sources of data for fuel cell costs, Black & Veatch determined that the best source of current fuel cell costs come from the Self-Generation Incentive Program (SGIP) offered by the state of California, which has funded a significant portion of the fuel cell installations in the United States.

Figure 3-10 illustrates historical SGIP data on fuel cell costs compiled by the NREL.[7] The cost data have been normalized for all years to 2010 dollars. This figure shows that the installed cost of fuel cells increased (in 2010 dollars) over the period from 2003 to 2013, which would seem to indicate that economies of scale have not yet been achieved by any of the fuel cell technologies described previously. This trend appeared in all size categories (i.e., less than 500 kW, 500 to 1,000 kW, and greater than 1,000 kW).



NREL cdp_stat_08
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Eligible Costs May Include: Planning & Feasibility Study, Engineering & Design, Permitting, Self-Generation Equipment
Waste Heat Recovery Costs, Construction & Installation Costs, Gas & Electric Interconnection, Warranty, Maintenance Contract
Metering, Monitoring & Data Acquisition System, Emission Control Equipment Capital
Gasline Installation, Fuel Gas Clean-up Equipment, Electricity Storage Devices, Bond to Certify Renewable Fuel
Sales Tax, Fuel Supply (digesters, gas gathering, etc.), Thermal Load, & Other Eligible Costs

*Data from the California SGIP.

Figure 3-10 **Stationary Fuel Cell Installed Cost (with and without incentives) – 2003 to 2013 (Source: NREL)**

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[7] Wilpe, et al. "Evaluation of Stationary Fuel Cell Deployments, Costs and Fuels," 2013 Fuel Cell Seminar and Energy Exposition, Columbus, Ohio, October 23, 2013.

3.2.2.1 Current Costs

The California Public Utilities Commission (CPUC) publishes eligible projects costs information by project.[8] Eligible costs include a variety of project costs: engineering costs, permitting costs, cost of equipment and installation, and interconnection costs.

Within the SGIP database, there are 143 fuel cell projects that applied for SGIP funding in 2012, 2013, and 2014.[9] The vast majority of these 2012 to 2014 projects (i.e., 130 projects) are electricity-only projects employing fuel cells supplied by Bloom. The remainder of these projects are CHP projects employing fuel cells supplied by Doosan (11 projects under the ClearEdge and UTC brand names) or FuelCell Energy (2 projects). Capital costs for these projects, based on the total eligible costs listed in the SGIP database, are summarized in Table 3-10.

Table 3-10 Fuel Cell Projects Applying for SGIP Funding in 2012 to 2014

TECHNOLOGY	SUPPLIER	APPLICATION	NUMBER OF PROJECTS(1)	TOTAL INSTALLED CAPACITY (MW)	AVERAGE PROJECT SIZE (KW)	AVERAGE PROJECT COST(2) ($/KW)
SOFC	Bloom	Electricity-only	130	52	400	12,000
PAFC (small-scale)(3)	Doosan(4)	CHP	6	0.18	30	17,400
PAFC (large-scale)(3)	Doosan(4)	CHP	5	4.0	800	9,200
MCFC	FuelCell Energy	CHP	2	2.8	1,400	6,200

Source: CPUC, SGIP Quarterly Projects Report (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/).

Notes:

1. Number of projects identifies projects that have applied for SGIP funding in 2012, 2013, and 2014 (excluding projects with status of “canceled” or “suspended.”)
2. Average project cost is based on total eligible costs listed in SGIP database.
3. Because of significant variations in scales, PAFC projects are split into two categories: small-scale projects ranging in size from 15 to 80 kW and large-scale projects ranging in size from 400 to 1,200 kW.
4. Doosan includes projects supplied by UTC and ClearEdge.

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[8] California Public Utility Commission, Self-Generation Incentive Program, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.

[9] This total excludes projects that have either been canceled or are currently suspended.

For Bloom's electricity-only SOFC projects, rated capacities of the projects ranged from 210 kW to 1,050 kW, with most projects reporting costs between $11,000/kW and $13,000/kW. Project costs for PAFC systems were split into two categories: smaller scale (i.e., less than 100 kW) and larger scale (i.e., greater than 400 kW). These projects are defined as CHP projects within the SGIP database. Total eligible costs for the smaller scale category average $17,400/kW, while total eligible costs for the larger scale category average $9,200.

Project costs for MCFC systems are based on two projects identified as CHP projects. The eligible costs for these two projects (each rated at 1,400 kW) were reported as $5,700/kW and $6,700/kW, respectively.

Based on the information summarized in Table 3-10, the capital cost of SOFC systems are greater than those of PAFC and MCFC. This is true even though the SOFC systems provide only electricity, while PAFC and MCFC projects listed in the SGIP database have CHP applications.

While the SGIP data represent installed system costs, Black & Veatch considers these values to be somewhat inflated in order to maximize investment tax credit (ITC) payment. Fuel cells are eligible for an ITC payment of 30 percent of system costs, up to $3,000/kW, effectively allowing the full 30 percent credit for system costs up to $10,000/kW. For example, the SGIP data for SOFC projects show system costs ranging from approximately $11,000/kW to $13,000/kW, while Bloom's published system quotes are around $8,000/kW[10]. Balance-of-system costs are acknowledged to account for some of that gap. Further complicating the estimation of actual fuel cell system costs are statements from major fuel cell suppliers, including Bloom and FuelCell Energy, implying negative profitability to date. The lack of cost transparency adds significant uncertainty to current and forecasted fuel cell cost estimates.

3.2.2.2 Forecasted Costs

Current capital costs greatly exceed targets for fuel cells identified by the DOE, which set 2020 targets at $1,500/kW for operation on natural gas.[11]

Several technical gaps have been identified as areas for significant cost reductions, and recent historical cost trends indicate that it will require a dramatic near-term reduction in cost for fuel cell suppliers to achieve DOE cost targets. Although not commercially available, Redox Power, a SOFC manufacturer who is currently working to commercialize its technology with Microsoft under a DOE grant, claims to have achieved a breakthrough design, lowering costs to about 10 percent of current commercial SOFC costs[12],[13]. Several other manufacturers including Toyota, Mitsubishi, and Honda are currently developing their own SOFC technologies. This market momentum may reduce system costs for SOFC and, in turn, drive down costs for MCFC and PAFC. While fuel cell cost forecasts are uncertain, and even current costs are considered to be vague (as discussed in Subsection 3.2.2.1), Black & Veatch has concluded that fuel cell system costs reported by SGIP are somewhat inflated and, therefore, has assumed for analysis purposes that 2016 costs are about one-third lower than SGIP reports. To test whether a dramatic drop in costs would be financially viable, Black & Veatch assumed that the market goal of $1500/kW would be met for all fuel cell

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[10] http://www.seattle.gov/light/news/issues/irp/docs/dbg_538_app_i_5.pdf.

[11] U.S. DOE, Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan (2012).

[12] http://www.technologyreview.com/news/518516/an-inexpensive-fuel-cell-generator/.

[13] http://www.dailytech.com/Microsofts+New+Fuel+Cell+Partner+is+Ready+to+Blow+Away+the+Bloom+Box/article36118.htm.

technologies by 2035. This cost forecast is not necessarily supported by the recent historical market trends; however, without a significant cost reduction, these technologies will not be financially feasible in DG applications such as those considered in this assessment.

3.3 MICROTURBINES

Microturbines are small combustion turbines that operate at very high speeds (i.e., more than 40,000 revolutions per minute [rpm] and up to 100,000 rpm). Microturbines, as shown on Figure 3-11, are typically rated at less than 250 kW, but multiple units can be installed in parallel for higher capacity. They are available as modular packaged units that include the combustor, the turbine, the generator, and the cooling and heat recovery equipment. Because of the small system footprints, microturbine units are attractive for small- to medium-sized applications.

3.3.1 Technical Characteristics

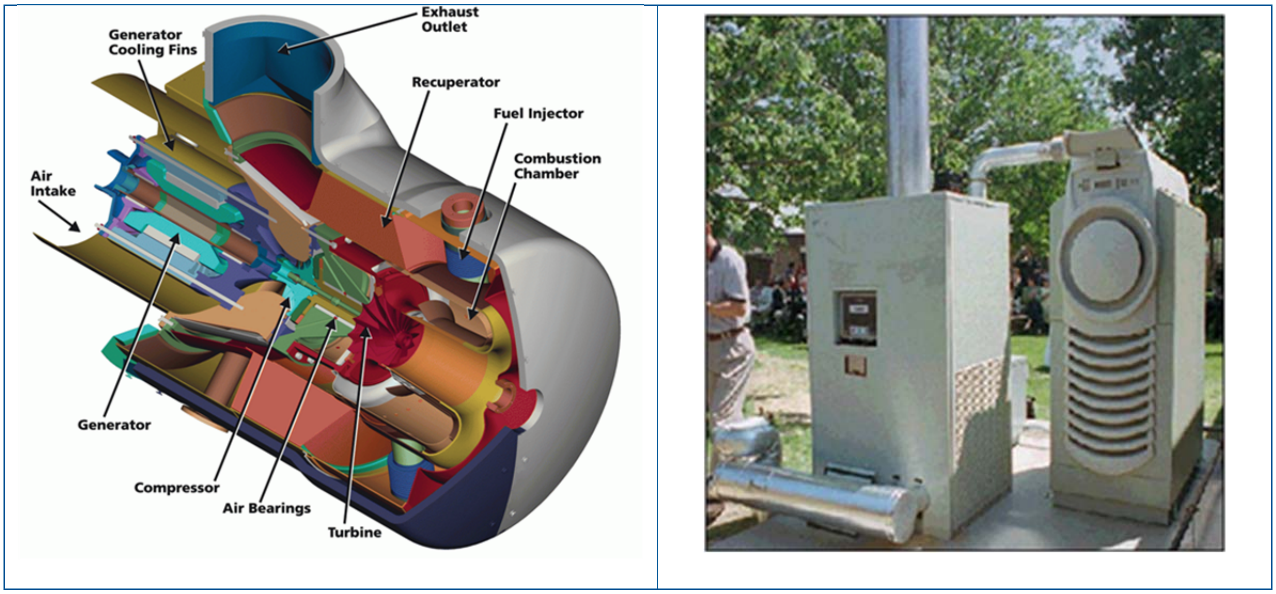

Figure 3-11 Cut-Away of Microturbine (left) and Typical Microturbine Installation (right) with Heat Recovery Module

Within a microturbine, the fuel gas is compressed and mixed with air in the combustor; combustion of the fuel/air mixture generates heat that causes the gases to expand. The expanding gases drive the turbine, which in turn drives a generator producing electricity. Heat from the turbine exhaust is recovered in a recuperator and is used to preheat incoming combustion air. This helps improve the overall operating efficiency of the unit.

Compared to reciprocating engines and engine-driven equipment, microturbines have the following operating characteristics:

- Lower efficiencies.
- Lower emissions.
- Greater inlet gas pressure requirements (ranging from 75 to 100 pounds per square inch gauge [psig]).
- Greater fuel gas treatment requirements (e.g., H_2S content must be reduced to less than 5000 parts per million volumetric [ppmv]).

The thermal efficiency of microturbine units is in the range of 25 to 30 percent (on a lower heat value [LHV] basis), depending on the manufacturer, ambient conditions, and the need for fuel compression. Similar to combustion turbines, efficiencies are reduced to some extent when operating at higher ambient temperatures (as the mass flow of combustion is reduced at higher ambient temperatures).

Microturbines are best operated continuously at full load as frequent start/stop cycles increase the frequency of periodic maintenance and reduce availability. These machines can operate at partial loads, although part-load operation negatively affects efficiency. For example, operation at 50 percent load would result in a thermal efficiency reduction to 25 percent (relative to 30 percent efficiency at full load).

Capstone C65 System

At present, there are two primary vendors for microturbine systems: Capstone Turbine Corporation and FlexEnergy. For the purposes of this characterization, Black & Veatch will provide information on Capstone's C65 system, which has a rated output of 65 kW. Performance of this machine is summarized in Table 3-11.

Regarding O&M costs, Capstone offers service packages at various levels of service (up to and including complete parts and labor for all maintenance activities). Lump sum fees for this service are paid on an annual basis. The annual fee for the complete O&M service package is equivalent to approximately $170/kW-yr.

Table 3-11 Performance Characteristics of Capstone C65 Microturbine

	CAPSTONE C65 MICROTURBINE
Unit Ratings	
Gross Power Output, kW	65
Output Voltage, V	480
Operating Parameters	
Fuel and Water Consumption/Discharge	
Natural Gas Consumption, scfm	14.2
Natural Gas Consumption, MMBtu/h (HHV)	0.87
Water Consumption (average), gpm	None
Water Discharge (average), gpm	None
System Efficiency(1)(2)	
Heat Rate (HHV), Btu/kWh	13,400
Electrical Efficiency, %	25
Emission Rates	
Carbon Dioxide (electricity only), lb/MWh	1,375
Nitrogen Oxides, lb/MWh	0.05
Sulfur Oxides, lb/MWh	Negligible
Particulate Matter (PM10), lb/MWh	Negligible

Source: Capstone Turbine Corporation

Notes:

1. Assumes HHV of natural gas of 1,025 Btu/scf.
2. System efficiency assumes electricity-only operation (i.e., no waste heat recovery or CHP operation).

3.3.2 Microturbine Costs

In the period from 2011 to 2014, only 8 microturbine projects were funded through SGIP. These projects are summarized in Table 3-12.

Table 3-12 Microturbine Projects Applying for SGIP Funding in 2011 to 2014

TECHNOLOGY	SUPPLIER	YEAR OF APPLICATION	RATED CAPACITY (KW)	ELIGIBLE PROJECT COST(1) ($)	ELIGIBLE PROJECT COST(1) ($/KW)
Microturbine	FlexEnergy	2011	726	2,831,300	3,900
Microturbine	Capstone	2012	65	504,200	7,750
Microturbine	Capstone	2012	65	504,200	7,750
Microturbine	Capstone	2012	585	2,510,100	4,290
Microturbine	Capstone	2012	600	1,129,600	1,880
Microturbine	Flex Energy	2012	750	3,310,500	4,410
Microturbine	Capstone	2012	1,000	4,541,300	4,540
Microturbine	Capstone	2013	1,000	3,067,100	3,070

Source: CPUC, SGIP Quarterly Projects Report (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/).
Notes:
1. Eligible project cost is based on total eligible costs listed in SGIP database.

For the Capstone installations of 65 kW, costs were reported to be $7,750 per kW in 2012, while larger systems (greater than 500 kW) ranged from $3,000 to $4,500 per kW, with the exception of the 600 kW Capstone system with a reported cost of $1,880 per kW.

Based on recent price quotations obtained by Black & Veatch for microturbines and ancillary equipment, equipment costs are approximately $2,500 per kW to $3,000 per kW. Therefore, when adding project development and installation costs, the reported costs from SGIP would be consistent with these recent equipment quotations and be representative of current installed costs.

3.3.2.1 Forecasted Costs

Because of the relatively mature state of microturbine technology, Black & Veatch does not foresee significant cost reductions in microturbine project costs over the long term. Therefore, these project costs are anticipated to be flat over the modeled project period in real dollars.

4.0 Financial Assessment

To model project financials, Black & Veatch modeled each of the technologies for a number of commercial customer types using a modified scripting of NREL's SAM software. The model incorporates technical performance parameters, system capital and O&M costs, project financing and taxes, incentives, and utility rate data, together with customer load data, to produce a suite of results including net present value (NPV), payback period, levelized cost of energy (LCOE), annual cash flow, and annual energy savings. Black & Veatch modeled scenarios for 2016 and 2035 for all technologies and customer types. For BESS, the system was tested with and without solar PV. Also, it was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. For each customer type, each of the technologies was also sized to meet either the customer load or minimum technology unit size. For both the 2016 and 2035 cases, Black & Veatch also tested two utility rates escalating two ways: at the CPI of 2 percent, and at CPI plus 1 percent (CPI + 1). Additionally, fuel cells and microturbines were tested under base and low gas price scenarios.

4.1 MODEL ASSUMPTIONS

Black & Veatch developed technical and financial assumptions to be input into the SAM model for each scenario, many of which were derived from the technical characteristics discussed in Section 3.0. These inputs are summarized in the following section.

4.1.1 Technical and Cost Assumptions

For this analysis, Black & Veatch used as input the technical parameters and cost forecasts developed in Section 3 for the various technologies.

Table 4-1 and Table 4-2 summarize the technical and cost inputs to the financial assessment. For BESS, Black & Veatch opted to model lithium ion technology only, as the technology has better round-trip efficiency than flow batteries and are more practical at a small scale.

Table 4-1 Technical and Financial Assumptions - BESS (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KWH)	CAPITAL COST ($/KWH)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)	CAPITAL COST ($/KWH)	FIXED O&M ($/KW-YR)	ROUND-TRIP EFFICIENCY (%)
BESS	10	1500	20	87	400	20	87

For the 2035 case, the improvements in fixed cost for fuel cells and BESS were assumed as discussed in Section 3.0. In the case of SOFC, a heat rate improvement on the order of 20 percent higher than that of current commercial systems was assumed. This assumption is based on the gap between existing commercial systems and the technically achievable efficiency for SOFC. Other commercial fuel cell technologies (MCFC, PAFC) and microturbines currently perform near their technical potential; thus, no heat rate improvement is applied. Similarly, no improvement is assumed for BESS round-trip efficiency in the 2035 case.

Table 4-2 Technical and Financial Assumptions - Fuel Cells and Microturbines (2014$)

		2016			2035		
TECHNOLOGY	SIZE (KW)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)	CAPITAL COST ($/KW)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
SOFC	210	8000	1000	7000	1500	150	5600
MCFC	300	4000	300	8000	1500	150	8000
PAFC	400	6000	150	9000	1500	150	9000
Microturbine	65	4000	170	13400	4000	170	13400

Table 4-3 shows the gross-to-net loss assumptions applied to fuel cells, microturbines, and BESS. In the case of fuel cells, rather than apply a percentage year-to-year degradation, an overall system de-rate was applied to better represent the stack replacement under the assumed O&M practices for commercial systems. Black & Veatch has assumed that fuel cell technologies will improve through advances identified in Section 3.2, hence this de-rate is reduced for the 2035 scenarios.

Table 4-3 System Loss Summary for Fuel Cells and Microturbines

LOSS CATEGORY	LOSS (%)
Nameplate Losses	99
Availability	98
De-rate for Stack Degradation – 2016 (Fuel Cell Only)	90
De-rate for Stack Degradation – 2035 (Fuel Cell Only)	95

Fuel cells and microturbines are modeled as fueled by natural gas. Both technologies are capable of running on biogas, but such a project would require a unique location, for example a food processing plant, landfill, or wastewater treatment facility. Black & Veatch has assumed for the purposes of this analysis that the evaluated commercial customer types would likely not have the ability to utilize biogas for this reason. Such operation would also add to the capital and O&M costs and, in some cases, reduce life span of some system components. The natural gas prices used are based on current published commercial rates from NW Natural, the gas utility serving Portland, and escalated at the growth rate calculated from base and low wholesale price forecasts provided by PGE,[14] as shown on Figure 4-1 and in Table 4-4.

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[14] NW Natural Summary of Monthly Sales Service Billing Rates: https://www.nwnatural.com/uploadedFiles/Oregon_Billing_Rate_Summaries.pdf.

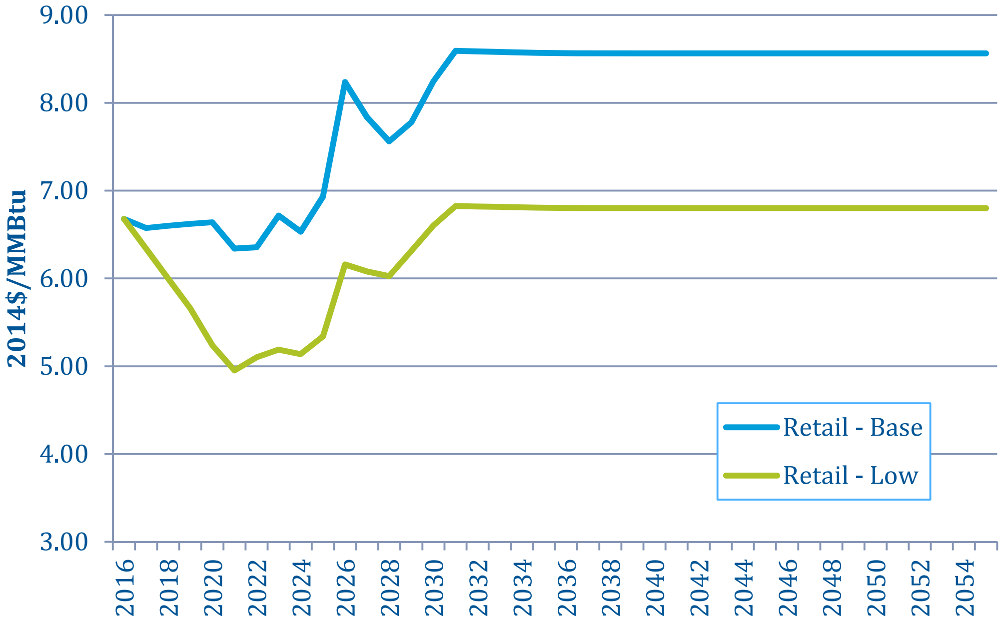

Figure 4-1 **Retail Natural Gas Forecast, Base and Low Cases (2014$)**

Table 4-4 **Natural Gas Wholesale and Retail Commercial Forecast (2014$)**

	2014$/MMBTU			
	PGE FORECASTED WHOLESALE PRICES		ESTIMATED RETAIL PRICES	
	BASE	LOW	BASE	LOW
2016	3.86	3.86	6.68	6.68
2017	3.80	3.67	6.57	6.34
2018	3.82	3.47	6.60	6.00
2019	3.83	3.28	6.62	5.66
2020	3.84	3.03	6.64	5.24
2021	3.67	2.87	6.34	4.95
2022	3.68	2.95	6.35	5.10
2023	3.89	3.00	6.72	5.19
2024	3.78	2.97	6.53	5.14
2025	4.01	3.09	6.93	5.34
2026	4.77	3.56	8.24	6.16
2027	4.53	3.52	7.83	6.08
2028	4.38	3.49	7.56	6.03
2029	4.50	3.65	7.78	6.31
2030	4.77	3.82	8.25	6.60
2031	4.97	3.95	8.59	6.82
2032	4.97	3.95	8.59	6.82
2033	4.96	3.94	8.58	6.81
2034	4.96	3.94	8.57	6.81
2035	4.96	3.94	8.57	6.80

4.1.2 Financial and Incentive Assumptions

The following are incentives that were reviewed for the analysis and matched to eligible technologies. Each incentive was applied to the eligible technologies for the various 2016 modeling scenarios:

- **Federal ITC:** A tax credit equal to 30 percent of eligible project costs for fuel cells and 10 percent of eligible costs for microturbines.
- **Federal Modified Accelerated Cost Recovery System (MACRS):** Five years for fuel cells, microturbines, and energy storage.
- **Oregon State Renewable Energy Systems Property Tax Exemption:** Of the technologies considered in this analysis, only fuel cells are explicitly included, although it has been assumed that the exemption is available to microturbines and energy storage.
- **Energy Trust of Oregon (ETO):** 50 percent grants for a number of renewable energy technologies including fuel cells; however, eligibility is limited to those projects using a renewable fuel. The Black & Veatch assessment considers only natural gas as a fuel, so fuel cells are not eligible.
- **ETO Solar Incentive:** Similar to the assumptions for Black & Veatch's Solar Market Study, it was assumed that the solar portion of the solar PV and BESS system would be eligible. Table 4-5 summarizes the incentives applied in the financial assessment.
- **Oregon State Net Energy Metering (NEM)**: PGE customers are credited at their utility rate schedule for excess generation, rolling over from month-to-month. Any excess generation remaining at the end of the year is not credited to the customer. This effectively caps a project under NEM at the customer's total annual consumption. Fuel cells running on natural gas are eligible, but microturbines and BESS are not. Black & Veatch has assumed a solar PV plus BESS system would be eligible for net metering.

Table 4-5 Available Financial Incentives in 2016 Cases

TECHNOLOGY	FEDERAL ITC	FEDERAL MACRS	PROPERTY TAX EXEMPTION	ETO	NET METERING
SOFC	30%	Eligible	Eligible	Not Eligible	Eligible
MCFC	30%	Eligible	Eligible	Not Eligible	Eligible
PAFC	30%	Eligible	Eligible	Not Eligible	Eligible
Microturbine	10%	Eligible	Eligible	Not Eligible	Not Eligible
BESS	Not Eligible	Eligible	Eligible	Not Eligible	Not Eligible
BESS + Solar PV	Solar Portion Only	Eligible	Eligible	Solar Portion Only	Eligible

For the 2035 cases, incentives are assumed not to be available, except for the 5-year MACRS.

The analysis period for all projects has been set to 20 years. As discussed in Section 3.0, the estimated project life spans for some technologies may be significantly less than 20 years, particularly in the case of fuel cells. However, O&M cost data have been estimated based on full-service warranties and is correspondingly high for those technologies with short life spans to account for frequent fuel cell, turbine, or other component replacement. In the case of energy storage, as discussed in Subsection 3.1.1, full daily cycling may result in a life span of approximately 10 years. Black & Veatch has assumed that the battery system will be cycling daily but not necessarily at full discharge, so should be able to operate for the 20 year test period.

All projects are assumed to be customer-owned with no debt financing. Table 4-6 summarizes the financial modeling assumptions, though schools were modeled as tax-exempt entities. It is important to note that the payback calculation reduces "energy savings" for tax-paying entities by their tax rates because they would have otherwise have been able to expense their electric bill as a tax-deductible item. The impact of this calculation between tax-paying and tax-exempt customers is significant on payback calculations, even though tax-paying commercial customers do benefit from MACRS and are able to deduct the asset as a capital expense.

Table 4-6 Financial Modeling Assumptions

FINANCIAL ASSUMPTIONS	
Analysis Period (Years)	20
Federal Income Tax (%)	35.0
State Income Tax (%)	7.6

4.1.3 Customer Load

It was important to use different customer types to understand how different load shapes may benefit through electricity bill reductions for both demand and energy charges, under each of their respective rate classes. Customer load profiles (hourly electricity demand) were obtained from DOE data compiled for all Typical Meteorological Year 3 (TMY3) locations in the United States, using the DOE commercial reference building model[15]. The dataset corresponding to the Portland International Airport TMY3 location was used for this analysis. Commercial customer types are presented in Table 4-7 together with summary statistics. PGE rate schedules used in the analysis are summarized in Table 4-8.

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[15] US DOE Commercial and Residential Hourly Load Profiles, openEI.org : http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Table 4-7 Commercial Customer Type Load Summary

COMMERCIAL CUSTOMER TYPE	ENERGY USE (MWH)	AVERAGE DEMAND (KW)	PEAK DEMAND (KW)	MINIMUM DEMAND (KW)	LOAD FACTOR (%)	ASSIGNED PGE RATE SCHEDULE
Full Service Restaurant	301	34	64	15	54	83
Hospital	8770	1001	1387	632	72	85
Large Hotel	2331	266	421	124	63	85
Large Office	5698	650	1718	211	38	85
Medium Office	682	78	270	19	29	85
Outpatient	1228	140	307	36	46	85
Primary School(1)	810	92	273	40	34	85
Quick Service Restaurant	186	21	37	9	58	83
Secondary School(1)	2488	284	908	87	31	85
Small Hotel	549	63	126	32	50	83
Small Office	61	7	19	2	37	32
Stand-Alone Retail	290	33	90	4	37	83
Strip Mall	270	31	84	3	37	83
Supermarket	1614	184	357	76	52	85
Warehouse	238	27	85	6	32	83

(1)Primary and secondary schools are tax-exempt customer types and are modeled as such.

Table 4-8 PGE Commercial Rate Schedule Summary (2014 Rates)

SCHEDULE	PEAK DEMAND (KW)	OFF-PEAK RATE ($/KWH)	PEAK RATE ($/KWH)	DEMAND CHARGE ($/KW)
32	0 to 30	0.0827	0.0827	0
83	31 to 200	0.0728	0.0831	5.6753
85	201 to 4000	0.0639	0.0742	5.0573
89	> 4000	0.0594	0.0697	3.8522

Results for the various technologies are presented in the following sections.

4.2 ENERGY STORAGE

For the energy storage analysis, Black & Veatch tested two configurations: BESS alone and BESS with PV. Black & Veatch developed a modified scripting of SAM to model BESS in both configurations. Energy storage is modeled to reduce peak demand and associated demand charges, as well as shifting load between on-peak and off-peak hours. Figure 4-2 illustrates how BESS can operate with a PV system where the BESS shifts load during the peak hours to off-peak hours. It should be noted that this example uses a 400 kWh BESS for illustrative purposes; the actual model runs utilized a much smaller system size, as discussed below.

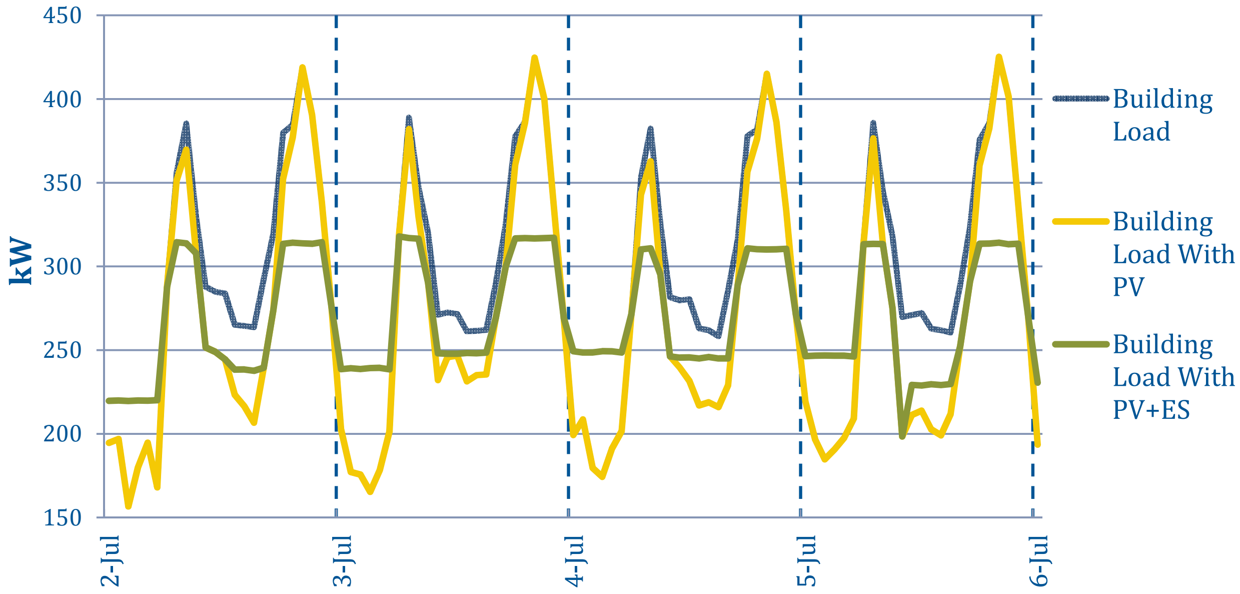

Figure 4-2 Illustrative Example of a Large Hotel Using 400 kWh BESS and PV

For financial modeling purposes, we modeled only lithium ion battery technology, due to the availability of smaller system sizes and significantly better round-trip efficiencies than flow batteries.

4.2.1 System Size

For the BESS plus PV systems, the PV systems were sized using NREL commercial customer profile data and estimates of average available rooftop space. Table 4-9 shows the PV system sizes used in the BESS plus PV cases.

Table 4-9 Solar PV System Size by Customer Type

COMMERCIAL CUSTOMER TYPE	PV SYSTEM SIZE (KW)
Full Service Restaurant	36
Hospital	262
Large Hotel	113
Large Office	249
Medium Office	116
Outpatient	55
Primary School	481
Quick Service Restaurant	16
Secondary School	686
Small Hotel	70
Small Office	36
Stand-Alone Retail	162
Strip Mall	146
Supermarket	293
Warehouse	338

To determine the battery energy storage system size, Black & Veatch ran the model using step sizes of 5 kWh and evaluated the results in terms of system size (kWh) versus payback years. In all cases, with and without PV, it can be seen that the payback continues to increase with additional storage capacity. Figure 4-3 shows the payback periods versus increasing system size for each customer. Based on this result, the battery systems have been sized to the minimum available system size of 10 kWh, as larger systems have diminishing benefits to load reduction. Black & Veatch notes that the results for small customer loads, such as warehouse, small office, quick service restaurant, are erratic beyond 10 kWh, as the system size is close to their average load and so are not shown in the graph on Figure 4-3.

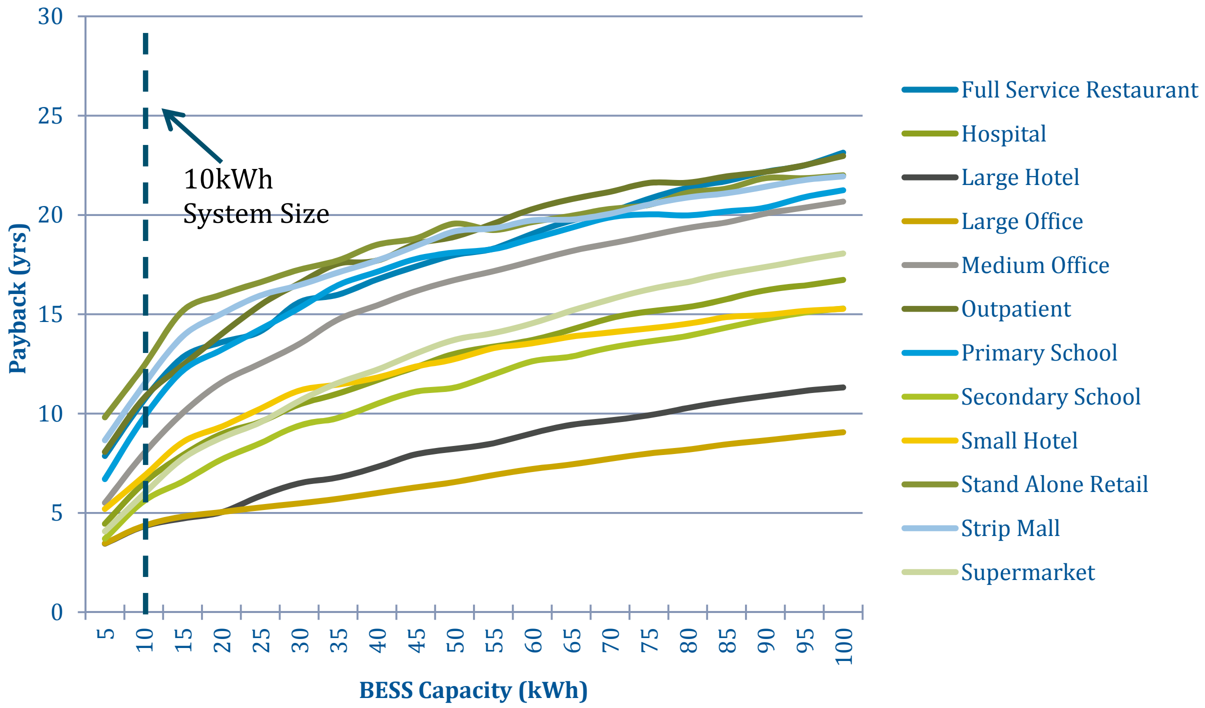

Figure 4-3 BESS Payback Curves, 2035 CPI+1

4.2.2 Results

Figure 4-4 and Figure 4-5 show the payback in years for all customer types for the 2016 and 2035 energy storage and energy storage with PV for the CPI + 1 case. It should be noted that for some of the systems that show paybacks of 25 years, the payback periods are actually well in excess of 25 years, and, therefore, not financially viable. As can be seen, particularly in the 2016 BESS-only cases, the long customer paybacks indicate poor financial feasibility. Because of the small margin between the TOU rates, there is little opportunity to take advantage of arbitrage from load shifting. Since the on-peak rates are only around 15 percent higher than the off-peak rates, after factoring in the round-trip charge/discharge efficiency of the battery system, there is very little positive (and in some cases slightly negative) financial advantage to charging during off-peak periods and discharging during on-peak periods. Given this condition, the primary advantage of energy storage is, therefore, in reducing the peak demand charges. In most cases, these charges are relatively low, further disadvantaging the energy storage financials. This is also true for the 2035 BESS-only cases, although decreased capital costs show customers with some reasonable paybacks.

In general, in 2035, customers under the large commercial customer rate (Schedule 85) with higher demand charges appear to benefit most from a BESS system with lower paybacks, around 5 years. Customers under Schedule 83 appear to achieve paybacks of about 10 years. The small office, under Schedule 32, does not benefit from BESS at all since there is no demand charge associated with that tariff.

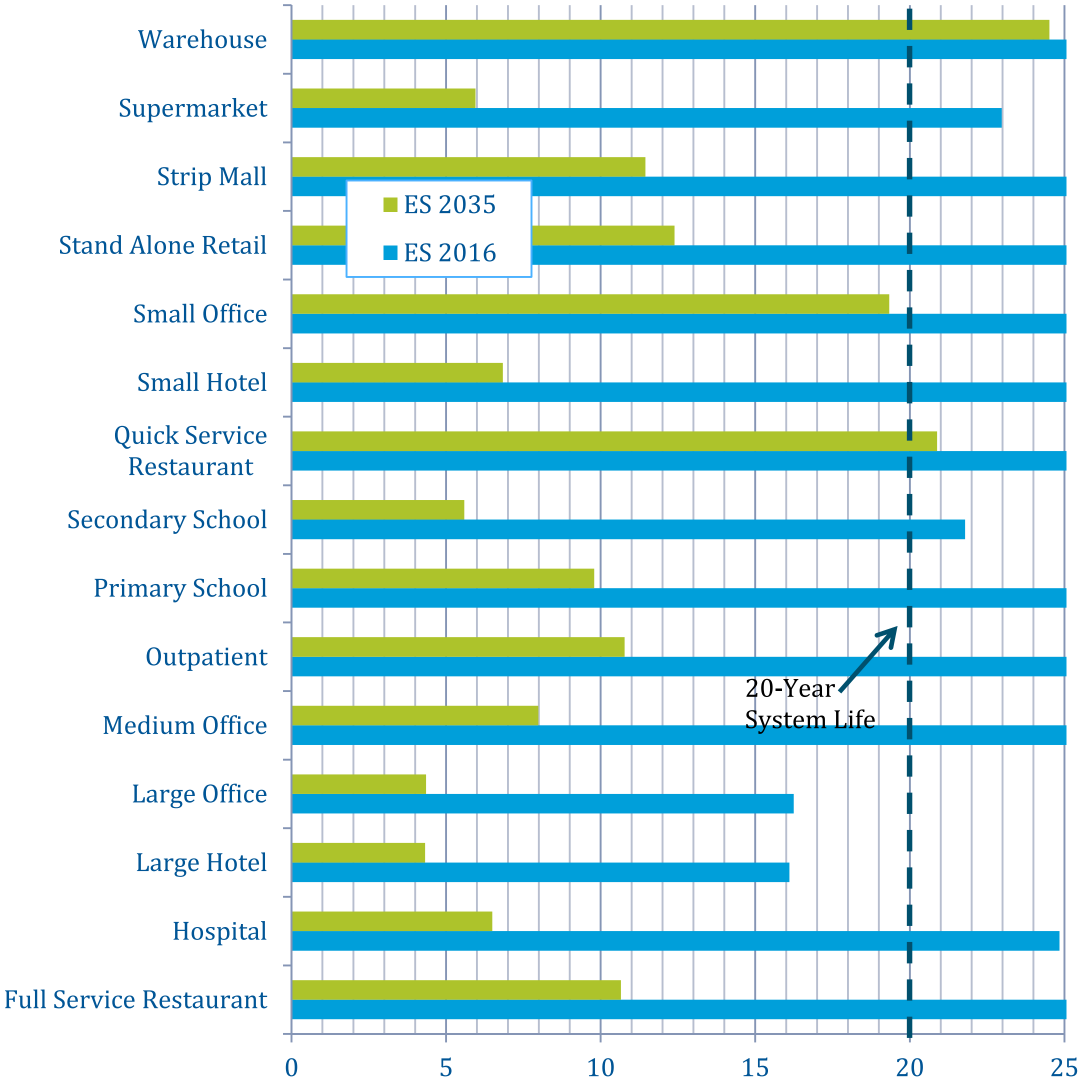

Figure 4-4 BESS Only Payback by Customer Type

Table 4-10 summarizes the payback for BESS Only under both the CPI and CPI+1 cases. Payback periods for CPI cases are greatly increased depending on the customer type.

Table 4-10 BESS Only System Payback Summary by Customer Type

	SYSTEM PAYBACK - CPI		SYSTEM PAYBACK - CPI +1	
	ES 2016	ES 2035	ES 2016	ES 2035
Full Service Restaurant	47.0	13.8	37.7	10.7
Hospital	28.6	8.2	24.8	6.5
Large Hotel	17.7	5.1	16.1	4.3
Large Office	17.9	5.2	16.2	4.4
Medium Office	34.6	10.0	29.6	8.0
Outpatient	47.6	13.9	38.0	10.8
Primary School	42.1	12.3	35.1	9.8
Secondary School	24.4	6.9	21.8	5.6
Quick Service Restaurant	>80	28.8	62.2	20.9
Small Hotel	30.1	8.7	26.0	6.8
Small Office	>80	>80	59.2	19.3
Stand Alone Retail	53.4	15.7	42.5	12.4
Strip Mall	49.5	14.5	39.9	11.4
Supermarket	26.2	7.5	23.0	6.0
Warehouse	>80	32.0	67.2	24.5

When combined with a PV system, the total system payback varies by each customer type's unique demand profile and PV system size. However, these payback calculations are worse than PV alone, so it does not appear to be financially practical to install BESS when PV currently enjoys the benefits of net metering.

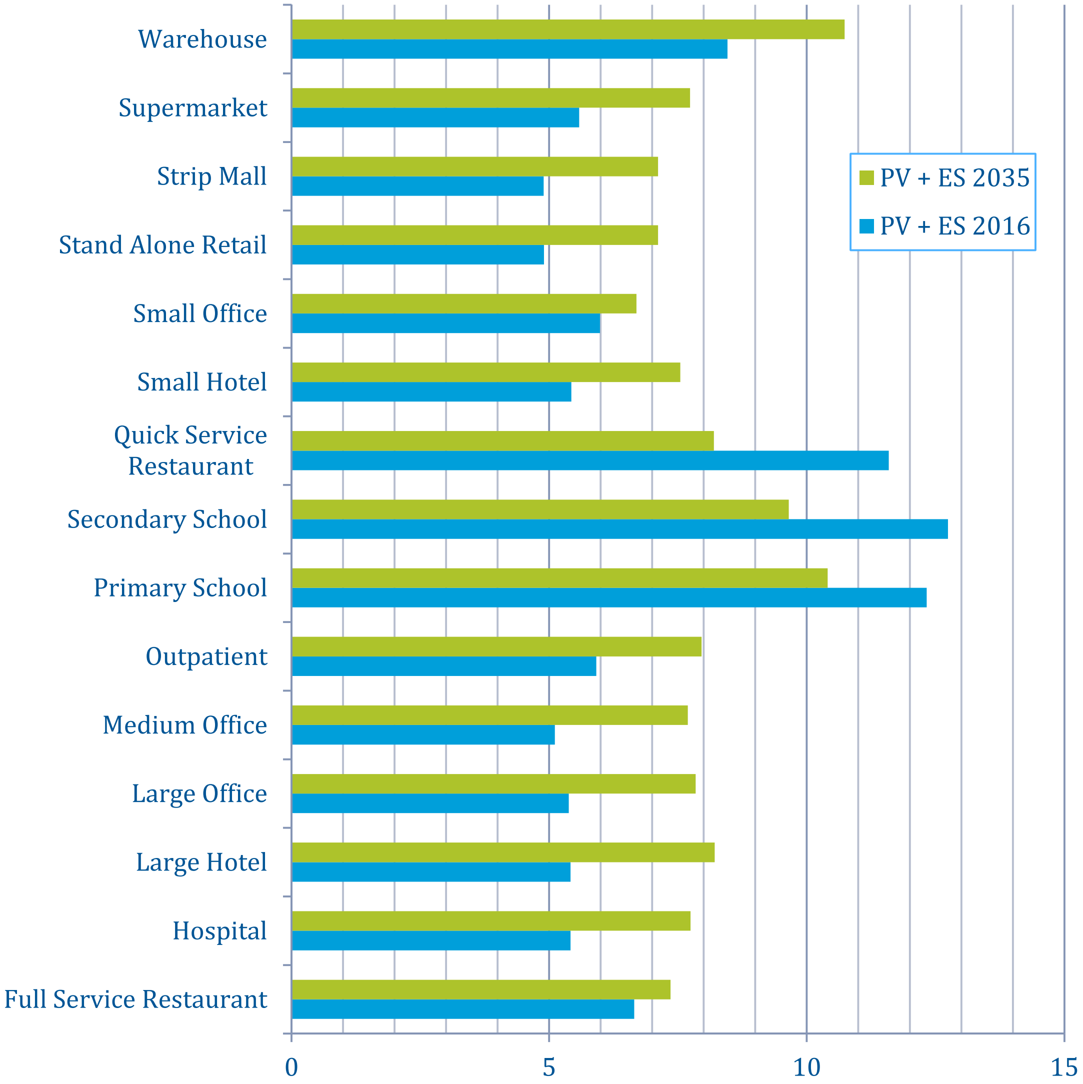

Figure 4-5 **BESS plus PV System Payback by Customer Type**

4.3 FUEL CELLS

Fuel cells were modeled for each technology discussed in Section 3.2: SOFC, MCFC, and PAFC. Currently, high capital and O&M costs limit commercial fuel cell use to areas with strong financial incentives, primarily under California's SGIP program. Furthermore, many current applications take advantage of the CHP capabilities of some fuel cell systems; whereas, Black & Veatch focused strictly on electric-only applications, which present somewhat limited opportunity. Black & Veatch has assumed, as shown in Table 4-2, that fuel cell costs will decrease dramatically by 2035, and in the case of SOFC, may achieve higher efficiencies in the 2035 cases. There is high uncertainty associated with these assumptions, but they are considered to be reasonable assumptions to test for long-term feasibility.

4.3.1 System Sizing

Fuel cells are modeled to run as baseload power (i.e., full nameplate capacity) with minimal load following capabilities. As fuel cells are eligible for net metering, systems have been sized for each customer type according to the average electricity demand, shown in Table 4-7. Since current commercial SOFC, MCFC, and PAFC systems are available modularly at capacities of 210 kW, 400 kW, and 300 kW, respectively, for each technology type (as identified in Section 3.0), customer types with average demand that is below the capacity of one single unit have been excluded, assuming it would not be financially viable to operate an oversized system under net metering rules. Table 4-11 shows the remaining customer types of sufficient size to be included in the financial assessment for fuel cells, along with the ultimate system size modeled for each fuel cell technology.

Table 4-11 Fuel Cell Customer Type and System Size

CUSTOMER TYPE	SYSTEM SIZE (KW)		
	SOFC (210 KW SYSTEM)	PAFC (400 KW SYSTEM)	MCFC (300 KW SYSTEM)
Hospital	840	800	900
Large Hotel	210	NA	300
Large Office	630	400	600
Secondary School	210	NA	300
Supermarket	210	NA	300

4.3.2 Results

In both the 2016 and 2035 case, the combination of capital, O&M, and natural gas fuel costs prohibit cost savings against the utility electricity rates, even with available incentives and a 1 percent rate escalation (the CPI + 1 case). Table 4-12 shows the system payback results for the CPI + 1 case.

Table 4-12 Fuel Cell System Payback by Customer Type, CPI + 1 Case, Base Fuel Cost

	2016			2035		
	SOFC	PAFC	MCFC	SOFC	PAFC	MCFC
Hospital	>80	>80	>80	27.3	>80	>80
Large Hotel	>80	>80	>80	27.3	>80	>80
Large Office	>80	>80	>80	27.3	>80	>80
Secondary School	>80	>80	>80	12.1	>80	27.3
Super Market	>80	>80	>80	27.5	>80	>80

For the 2035 scenario, incentives are assumed to be unavailable, natural gas fuel costs are forecast to increase faster than the CPI rate, and even with the assumed dramatic reduction in capital and O&M costs, the various fuel cell technologies still do not show opportunity for payback within the project life. The only customer with a payback below the 20 year project life is the secondary school SOFC case, whose high load and tax-exempt status provide enough benefit to reduce its payback relative to the other customer types.

Fuel costs are clearly a sensitive input with significant impact on the results, and are more uncertain in the 2035 case. Black & Veatch also modeled all scenarios under a "low" fuel cost forecast. Using the lower fuel costs, paybacks are reduced somewhat; however, only the secondary school (at paybacks of 7.8 years and 17.5 years for SOFC and MCFC, respectively) achieves paybacks below the 20 year project life.

Table 4-13 summarizes the LCOE for the different fuel cell scenarios. In general, the real levelized cost of energy is higher than retail energy rates for larger commercial customers.

Table 4-13 Fuel Cell Real Levelized Cost of Energy Estimates (2014$/kWh)

		SOFC		MCFC		PAFC	
YEAR	NATURAL GAS	TAX-EXEMPT	TAX-PAYING	TAX-EXEMPT	TAX-PAYING	TAX-EXEMPT	TAX-PAYING
2016	Base	$0.27	$0.24	$0.14	$0.13	$0.15	$0.13
	Low	$0.26	$0.23	$0.13	$0.12	$0.14	$0.12
2035	Base	$0.08	$0.08	$0.10	$0.10	$0.11	$0.11
	Low	$0.07	$0.07	$0.09	$0.09	$0.09	$0.10

While Black & Veatch has not presented results for the customer types excluded for being below the minimum system size, those customers were modeled and payback periods for all scenarios significantly exceeded the estimated project life.

It should be noted that all fuel cells have been modeled for electricity generation only. Some fuel cell scenarios may prove to be cost-effective if used as a CHP application, but that was not evaluated in this study.

4.4 MICROTURBINES

Microturbines are modeled based on the Capstone C65, as discussed in Section 3.3. In general, microturbines are typically deployed in niche applications, and often under significant incentives such as California's SGIP program, as their lower efficiency and relatively high cost typically preclude financial feasibility. We have assumed, as shown in Table 4-2, that microturbine cost and performance will not improve from 2016 to 2035 as it is a well-established technology.

4.4.1 System Sizing

Microturbines are also modeled to run at baseload power, because of the additional wear and tear incurred for cycling and reduced heat rates if they are run at part load. Since microturbines are not eligible to be net metered in Oregon, and it was assumed that it would not be financially viable to sell the energy back to PGE at avoided cost, systems have been sized for each customer type based on the minimum demand, as shown in Table 4-7. Using the Capstone C65 as the minimum microturbine system size of 65 kW, customer types with minimum demand that is below the capacity of one single microturbine were excluded. Table 4-14Table 4-14 shows the customer types of sufficient size to be included in the financial assessment for microturbines, together with the ultimate system size.

Table 4-14 Microturbine Customer Type and System Size

CUSTOMER TYPE	SYSTEM SIZE (KW)
Hospital	585
Large Hotel	65
Large Office	195
Secondary School	65
Supermarket	65

4.4.2 Results

In all cases, for all customer types (including those below the minimum load requirement), and for both the base and low fuel cost forecast, the model results show that high capital and O&M costs, retail fuel prices, coupled with a relatively low efficiency, and lower incentive eligibility make this technology not feasible for commercial electricity-only applications under PGE's rate schedules. Microturbines may be more financially viable operating in CHP mode but will need a suitable thermal load to accommodate the microturbine.

Table 4-15 summarizes the LCOE for the microturbine scenarios.

Table 4-15 Microturbine Levelized Cost of Energy (2014$/kWh)

YEAR	MICROTURBINE		
	NATURAL GAS	TAX-EXEMPT	TAX-PAYING
2016	Base	0.16	0.16
	Low	0.14	0.14
2035	Base	0.17	0.18
	Low	0.15	0.15

5.0 Achievable Potential

Developing estimates of achievable potential for the DG technologies examined in this study is challenging in that these technologies under current financial conditions are not financially viable in the near-term, and long-term cost outlook is quite uncertain for many of these technologies. Another added complexity is that appropriately sizing of the systems, matched to a customer's load shape, really drives the financials. In order for the technologies to be financially viable, technology costs would need to drop substantially, additional policies and incentives would need to be put in place, and changes in rate structure are needed to promote adoption. Absent those conditions, Black & Veatch forecasts minimal adoption of these technologies over the study period. If any adoption occurs, it would be toward the latter decade (2026 to 2035) of the analysis period when better clarity on costs is available. The one major caveat in this study is that Black & Veatch focused on the impact of these systems on customer electricity bills but did not account for the value of reliability and power quality to the customer. These factors are much more difficult to value and could vary widely by customer type. PGE may want to consider studying these values to customers further in future analysis.

For the energy storage options in the near-term, BESS costs are not financially viable for any of the customer types, given the lack of available federal and state incentives as well as relatively low demand charges and little arbitrage opportunity with the TOU rates. As noted in Section 4.2, only lithium ion BESS technology was modeled: flow batteries have significantly lower round-trip efficiency which would result in poor financials. For the 2035 CPI+1 case, when demand charges increase faster than inflation, most customer types were found to show payback periods of less than 20 years, assuming a BESS cost of $400 per kWh in 2014$. While technically financially viable, similar to the Solar Generation Market Research Study that Black & Veatch developed for PGE, the likelihood of adoption for individual customers is still limited by the perceived payback period. Since there does not appear to be a maximum market penetration curve available for energy storage, if commercial customer preferences for BESS are assumed to be similar to solar PV (Figure 5-1), commercial customer types that see paybacks of around 5 years have about a 20 percent chance of adoption. Using the same curve, customer types that see paybacks closer to 10 years would have a 5 percent chance of adoption.

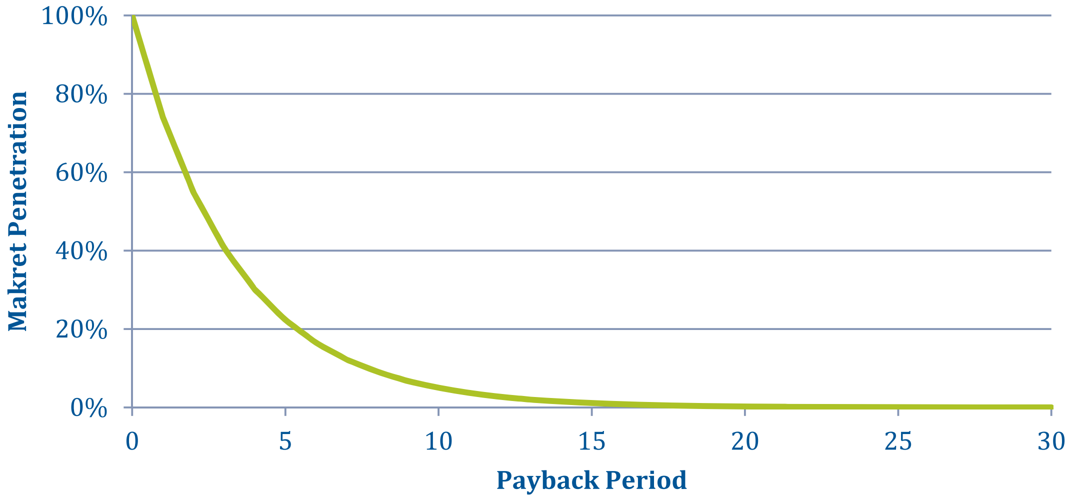

Figure 5-1 **Solar PV Maximum Market Penetration Curve Relative to Payback Period**

Therefore, assuming this curve holds true for BESS, only about 5 to 20 percent of commercial customers are likely to adopt by 2035. Since costs are only expected to drop to these low levels in the latter half of the study period (2026 to 2035), minimal adoption is anticipated prior to that time period. Assuming that 5 to 10 percent of PGE's commercial customers (approximately 104,000 customers) would consider BESS in the 2026 to 2035 time frame and that it is most practical to deploy smaller systems (10 kWh @ 2 hour capacity), the adoption over those 10 years could total 52 to 104 MWh or 26 to 52 MW of installations. Divided evenly across the 2026 to 2035 time frame, that is equivalent to approximately 2.6 to 5.1 MW per year of energy storage installations. Adoption may be higher if certain customer types, such as critical facilities (hospitals, schools, etc.), place some value on reliability and power quality associated with installing BESS and, thus, install larger systems and/or have wider adoption despite poor paybacks. However, this metric was not studied in this analysis.

Table 5-1 Forecasted Annual BESS Adoption

BESS CAPACITY (MW/MWH)	2016 TO 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Adoption	0	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2	2.6/ 5.2
High Adoption	0	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4	5.2/ 10.4

For the BESS plus solar PV cases, the addition of BESS to a solar installation does not improve the financials of the combined system, and, in fact, in the 2016 cases, BESS causes payback to increase. Therefore, in the near-term, given that solar PV installations are able to net meter, there is no incremental benefit to deploying an energy storage system until net metering is no longer available. By 2035, BESS costs will have fallen enough that BESS installations, combined with solar PV, will not alter the payback significantly compared to solar PV alone. However, this also implies that a customer would be ambivalent to installing a BESS with its solar PV system, unless net metering was no longer available. Therefore, based on this analysis, the deployment of BESS with solar PV systems is not practical until net metering is no longer available. If net metering is replaced with other policies, the deployment of BESS as part of a solar PV system may become financially viable, but this will depend on the rules around the alternative rate structures.

The analysis of fuel cells and microturbines in all cases, including low natural gas price cases, showed that none of these technologies result in financial payback. One exception is that the case for secondary schools in 2035 deploying SOFC, under a low natural gas price scenario with rates that increase at CPI + 1, may make some financial sense. However, this assumes that the installed system and O&M costs drop substantially and efficiency gains are achieved for the technology, which is highly uncertain given the technology status today. Aside from capital and O&M cost, the financials of these technologies relative to utility-supplied power are penalized in two ways: higher heat rates compared to PGE's system heat rate and natural gas priced at retail rates. These drawbacks are unlikely to change under any condition.

In this study, fuel cell and microturbine technologies were modeled for electricity production only and CHP modes were not considered in the financial model. However, most commercial fuel cells and microturbines can be configured as CHP systems. While CHP may improve these technologies' financials over electricity-only operation, CHP applications are limited to specific customers that can utilize both the energy and heat. Additional studies examining specific customer load would be needed to assess the potential of fuel cells and microturbines for CHP applications.

APPENDIX G. Dispatchable Standby Generation Study

Chapter 7, Supply Options, provides a detailed description of PGE's Dispatchable Standby Generators (DSG) program. In short, the program offers access to a fleet of diesel generators that provide non-spinning reserves to PGE’s system. PGE recommends continued expansion of the DSG fleet as a cost-effect action to meet the system’s non-spin needs.

In order to assess future MW of DSG needed, PGE engaged Energy and Environmental Economics, Inc. (E3) to prepare a methodology using their Renewable Energy Capacity Planning model (RECAP). As discussed in Chapter 5, Resource Adequacy, PGE used RECAP to determine the Company's capacity need, based on an adequacy measure of the ability to serve hourly load plus required operating reserves (spinning and non-spin). E3 used a two-step RECAP process to separate the “standby” capacity need (non-spin) from the “active” capacity need (load and spin):

1. RECAP runs for 2021, 2025, and 2030 with current DSG resources excluded and non-spin requirements removed. RECAP determined the capacity needed to achieve the 2.4 hr/yr reliability metric. This determined a need for active capacity, expressed as conventional units (CUs, defined as 100 MW blocks with 5 percent forced outage rating).
2. RECAP runs for 2021, 2025, and 2030 with current DSG resources included, non-spin requirements included, and additional active capacity resource included. RECAP determined the capacity needed to achieve the 2.4 hr/yr reliability metric. This determined the need for additional standby capacity, expressed as CUs.

PGE converted the CUs to DSG capacity and interpolated/extrapolated to calculate the incremental quantity needed for 2017-2030. Table G-1 illustrates the current fleet capacity[233], the targeted total fleet capacity, and the capacity deficit. The Action Plan discussed in Chapter 13, Action Plan, includes DSG actions to meet the targeted DSG fleet capacity.

TABLE G-1: Targeted DSG fleet capacity, MW

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Targeted Fleet Capacity	118	123	127	131	135	138	140	142	144	146	148	149	151	153
Current Fleet Capacity	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Deficit (Target - Current)	4	9	13	17	22	24	26	28	30	32	34	35	37	39

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[233] As projected for the end of 2016.

APPENDIX H. AURORA Market Prices

TABLE H-1: AURORA monthly on-peak prices, Reference Gas, Reference CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.4	26.4	24.5	19.9	18.5	16.1	23.0	24.8	25.8	24.8	26.5	29.5
2021	29.1	29.4	23.7	21.1	19.2	18.7	24.5	26.5	28.4	27.1	30.0	32.1
2022	42.7	42.9	38.5	36.2	33.4	30.3	38.9	41.1	42.8	41.9	43.7	45.4
2023	45.7	45.2	40.7	37.9	36.5	35.4	41.5	44.0	45.8	46.0	48.5	50.8
2024	51.0	49.2	45.4	40.7	38.3	28.1	44.4	47.6	50.4	49.0	49.9	53.3
2025	52.5	51.9	46.0	42.7	41.6	35.9	47.1	49.2	52.2	50.4	58.2	62.0
2026	63.1	63.5	49.0	44.8	40.7	34.0	49.4	51.5	54.0	53.8	64.2	67.2
2027	66.7	67.2	49.0	45.6	42.8	33.1	49.8	53.1	55.5	55.6	66.1	69.1
2028	68.9	66.8	54.5	49.9	44.1	35.1	55.4	59.5	62.9	62.9	70.2	73.1
2029	72.8	69.9	59.9	53.1	50.2	34.7	58.8	63.1	67.1	64.2	69.9	74.4
2030	72.8	70.8	62.8	54.9	48.2	33.9	61.5	66.1	71.3	69.9	71.3	77.1
2031	77.8	75.9	66.3	58.6	55.7	42.1	65.6	71.1	74.9	73.9	75.3	81.3
2032	81.0	79.4	67.7	61.3	55.0	39.9	70.3	77.5	78.3	76.8	80.8	84.5
2033	86.3	85.7	72.0	65.7	57.4	53.5	75.6	80.3	83.2	83.7	86.6	90.3
2034	90.1	89.8	76.3	67.5	59.6	44.3	79.3	83.9	87.0	86.8	89.5	94.6
2035	95.7	92.2	80.6	69.1	63.1	41.0	80.8	88.3	90.4	89.3	92.4	98.4
2036	99.0	94.7	84.0	72.1	54.9	32.8	84.3	90.6	97.2	96.7	95.7	102.7
2037	103.0	102.4	88.2	72.0	68.9	54.8	88.8	97.9	102.5	101.6	103.0	107.8
2038	108.0	108.0	91.0	77.4	62.2	45.9	96.4	104.5	108.5	108.1	110.6	114.3
2039	117.3	115.4	96.4	79.7	70.6	55.2	103.3	109.4	113.2	111.6	115.4	120.4
2040	121.6	118.7	100.5	87.6	71.9	53.5	109.0	116.2	124.3	120.2	123.3	126.4
2041	128.5	124.6	106.6	92.9	84.2	43.7	112.9	120.1	125.2	120.8	123.9	131.8
2042	132.9	129.7	110.4	97.5	73.9	42.2	115.8	127.6	131.9	126.2	128.3	136.0
2043	135.9	135.3	114.1	98.5	84.3	69.1	123.8	131.4	138.0	131.1	135.5	145.3
2044	150.4	145.8	125.4	107.3	87.8	77.9	132.3	143.1	146.7	143.6	147.1	153.1
2045	155.0	155.8	128.4	113.6	97.4	82.1	140.9	148.1	152.4	150.1	154.1	160.2
2046	165.2	158.9	140.3	119.7	100.9	86.9	146.0	160.5	166.2	160.2	161.5	167.8
2047	169.6	162.7	144.6	127.9	108.6	89.6	151.2	164.4	171.1	162.4	163.8	174.5
2048	174.7	170.3	145.4	129.9	103.8	83.3	158.1	166.3	173.4	167.6	172.3	179.5
2049	178.8	179.7	150.1	133.0	115.3	100.5	166.8	175.1	179.7	174.4	179.2	187.9
2050	186.1	185.7	155.5	139.9	126.8	100.8	171.4	183.4	188.4	183.6	188.6	194.3

TABLE H-2: AURORA monthly off-peak prices, Reference Gas, Reference CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.6	23.0	18.3	16.0	14.3	20.1	22.1	23.7	23.6	24.5	26.4
2021	26.8	26.4	21.9	19.2	16.9	14.9	20.9	23.1	25.8	25.2	26.8	29.3
2022	41.1	40.0	36.7	34.2	28.8	27.0	35.2	37.4	39.6	39.8	41.7	43.0
2023	42.7	42.1	38.5	35.4	34.6	32.6	38.5	40.5	42.7	43.1	45.8	47.1
2024	47.0	45.2	43.0	39.3	36.7	26.0	40.8	44.4	46.2	45.4	47.2	49.4
2025	49.2	48.0	43.3	40.3	38.6	33.4	41.5	45.9	48.2	47.6	54.6	56.4
2026	59.7	58.9	46.0	43.4	38.7	28.2	44.7	47.8	50.5	49.9	59.4	61.5
2027	62.1	60.8	46.5	43.9	41.1	32.8	45.4	49.2	51.7	52.1	61.1	63.3
2028	63.6	62.7	51.8	47.3	43.4	33.7	51.5	55.2	57.9	58.1	65.1	66.5
2029	67.3	64.9	57.7	49.6	49.3	31.2	52.8	58.9	63.3	60.9	66.2	68.1
2030	68.9	67.3	60.6	52.1	48.9	33.5	57.5	62.5	66.7	66.1	69.1	70.3
2031	74.6	72.9	63.1	57.7	56.1	42.4	61.5	67.2	70.5	69.7	72.7	75.3
2032	77.3	75.4	67.2	60.3	46.8	37.6	68.4	69.2	73.7	72.3	77.2	80.5
2033	83.1	81.6	71.5	65.2	60.4	48.2	71.7	75.1	80.2	78.8	82.9	86.3
2034	87.1	85.0	75.2	64.6	56.7	42.0	74.5	79.1	82.5	82.5	88.0	89.5
2035	91.3	89.5	81.7	69.3	64.6	54.2	76.4	85.4	88.0	84.0	90.6	92.0
2036	97.5	93.5	84.0	72.8	63.5	37.9	77.9	87.3	93.2	91.1	96.2	98.8
2037	100.9	100.4	87.5	75.0	68.7	51.3	85.8	94.7	98.0	98.4	100.8	103.2
2038	107.5	106.5	93.2	81.8	64.3	49.6	91.0	97.8	103.2	102.9	108.7	109.2
2039	114.0	113.0	96.6	89.4	68.8	70.4	100.7	104.3	110.3	110.8	112.6	115.8
2040	118.2	117.7	100.5	91.6	75.2	58.5	104.2	113.2	115.0	117.4	121.4	123.0
2041	125.6	121.6	109.9	99.5	82.2	56.3	110.6	117.0	125.3	117.9	127.6	124.0
2042	128.7	128.2	114.0	100.2	79.2	62.1	122.3	124.7	133.0	130.7	133.4	133.7
2043	138.1	133.5	119.0	105.9	97.7	77.7	115.5	127.5	135.8	132.9	132.8	139.2
2044	142.1	143.0	125.4	112.3	90.5	71.1	136.1	138.3	145.9	137.4	144.3	147.5
2045	150.9	152.5	130.1	125.2	101.4	79.6	139.3	145.4	150.5	146.5	154.1	159.2
2046	160.1	155.7	140.9	122.4	107.7	80.3	144.8	152.3	160.1	153.4	159.6	163.9
2047	165.5	162.0	144.5	129.5	116.0	82.0	151.1	160.8	166.5	164.5	166.2	173.2
2048	169.3	167.9	147.4	131.2	118.8	105.4	154.3	165.7	171.0	166.6	168.1	175.3
2049	176.8	176.6	152.0	140.1	122.1	90.6	158.5	169.6	176.5	167.0	172.9	181.9
2050	181.5	182.5	157.1	144.5	112.0	116.6	163.3	177.5	183.3	177.2	185.0	191.3

TABLE H-3: AURORA monthly on-peak prices, Reference Gas, No CO$_2$ Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.4	26.4	24.5	19.9	18.5	16.1	23.0	24.8	25.8	24.8	26.5	29.5
2021	29.1	29.4	23.7	21.1	19.2	18.7	24.5	26.5	28.4	27.1	30.0	32.1
2022	29.4	29.3	25.1	21.8	19.7	17.5	24.9	27.0	29.2	28.4	31.5	33.7
2023	33.0	32.9	27.7	24.2	21.5	20.4	27.1	30.0	32.4	32.6	36.6	38.9
2024	39.2	37.2	32.8	26.5	23.1	15.0	30.0	33.5	37.0	36.1	38.0	41.2
2025	39.8	39.2	32.1	26.8	24.8	19.7	31.6	34.2	38.0	36.2	46.2	49.9
2026	51.3	51.0	35.5	29.0	24.0	19.0	34.2	37.3	40.1	39.7	52.0	54.7
2027	54.3	54.2	34.7	29.5	25.2	18.4	34.0	38.2	40.6	40.4	52.8	55.7
2028	56.5	53.4	40.1	32.8	26.5	20.2	40.1	44.8	47.6	47.5	56.2	59.4
2029	59.5	55.5	44.1	35.8	32.0	18.3	42.5	47.8	52.0	48.1	55.0	60.3
2030	58.9	56.6	46.7	37.1	30.5	17.6	46.1	51.1	55.8	54.2	57.0	62.4
2031	61.7	59.5	48.1	37.6	34.8	24.2	47.2	53.5	57.7	55.9	58.3	64.2
2032	61.8	60.4	46.7	37.8	31.2	18.8	49.1	57.3	58.0	55.7	61.2	65.2
2033	65.3	64.2	48.7	38.9	30.5	28.0	51.1	57.0	59.7	59.4	64.9	68.2
2034	67.4	66.4	49.8	39.3	32.8	20.7	53.6	58.5	61.1	61.6	65.6	70.3
2035	70.6	66.3	51.8	39.7	34.6	17.8	51.2	59.0	63.1	61.5	66.2	72.1
2036	70.6	66.7	52.6	40.1	27.6	11.3	54.0	59.5	64.9	64.3	67.4	74.2
2037	72.8	71.7	55.3	38.7	35.2	25.9	55.2	63.5	69.6	66.4	71.8	77.8
2038	76.0	76.1	57.0	41.6	31.5	18.5	60.6	69.3	73.2	72.5	77.3	82.9
2039	81.9	79.3	58.1	42.6	36.9	25.3	62.8	70.7	75.6	73.0	80.5	86.0
2040	84.6	80.6	59.7	47.6	35.8	19.7	66.4	74.4	79.8	78.8	83.2	88.6
2041	88.7	84.1	66.1	50.4	47.3	14.4	65.2	74.9	81.9	79.2	84.0	93.1
2042	91.8	87.3	68.7	51.8	38.6	13.7	70.1	79.8	85.8	83.5	87.4	96.0
2043	94.7	91.2	69.0	52.4	43.9	30.5	71.9	82.2	89.6	86.1	91.0	102.0
2044	103.3	97.1	75.5	58.8	48.7	36.9	77.9	92.0	95.5	94.8	99.6	107.7
2045	107.2	103.2	77.8	63.0	52.7	39.0	81.6	93.3	98.8	97.9	103.8	111.6
2046	121.1	113.2	93.9	75.0	64.0	43.6	90.5	104.2	114.0	107.6	112.8	123.1
2047	129.4	121.7	105.0	86.1	77.1	48.7	102.7	112.2	124.0	115.7	121.6	134.5
2048	136.2	127.5	106.7	92.1	77.7	51.6	105.7	117.0	126.4	121.3	129.0	140.2
2049	139.3	134.3	114.1	96.2	84.9	67.1	110.5	123.0	132.9	128.4	136.4	146.0
2050	146.0	139.9	115.8	99.5	90.1	66.8	114.0	127.8	137.0	131.9	140.8	153.4

TABLE H-4: AURORA monthly off-peak prices, Reference Gas, No CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.6	23.0	18.3	16.0	14.3	20.1	22.1	23.7	23.6	24.5	26.4
2021	26.8	26.4	21.9	19.2	16.9	14.9	20.9	23.1	25.8	25.2	26.8	29.3
2022	27.1	26.7	23.9	19.8	15.7	14.2	21.6	23.8	26.7	27.2	29.1	30.8
2023	30.4	29.4	26.2	21.3	19.4	17.4	24.2	27.1	29.6	29.9	33.1	34.5
2024	34.8	31.8	29.9	24.8	21.1	12.5	25.6	30.4	32.5	31.6	34.6	36.7
2025	36.4	34.6	29.3	24.4	21.2	18.0	26.6	31.2	34.1	33.2	41.2	44.6
2026	47.7	46.6	31.8	27.3	21.8	14.2	29.5	34.3	36.7	35.4	46.4	49.4
2027	50.4	47.3	31.7	27.0	22.7	16.7	29.4	34.2	37.0	36.7	47.6	50.5
2028	51.5	49.3	36.7	30.4	25.9	18.3	36.2	41.2	43.3	43.1	51.5	53.0
2029	53.3	50.8	42.1	32.0	30.1	16.4	37.0	44.4	48.0	45.8	51.6	54.2
2030	54.9	53.1	45.3	35.2	30.0	17.7	42.8	48.1	51.6	51.0	54.5	56.3
2031	58.8	56.2	45.3	37.9	35.8	24.8	43.7	50.0	53.8	52.4	56.2	58.6
2032	59.0	55.7	46.9	36.9	26.0	19.0	46.9	49.5	54.3	52.4	57.4	60.3
2033	62.7	59.6	48.0	38.2	32.9	25.4	48.2	51.9	56.8	54.9	60.9	64.3
2034	63.3	61.2	48.4	37.3	30.2	18.8	48.5	54.0	57.7	57.0	63.9	65.2
2035	64.2	62.6	52.5	40.2	37.2	28.8	48.2	56.6	60.2	57.1	63.6	65.5
2036	68.1	64.5	53.1	40.2	32.9	17.4	48.6	55.8	62.3	59.1	66.1	69.7
2037	69.8	68.0	53.3	43.5	37.5	23.0	51.8	60.1	65.2	63.8	68.7	71.5
2038	74.6	72.0	58.0	45.9	32.9	20.9	53.4	62.5	67.8	64.9	72.7	76.3
2039	78.4	75.1	59.5	49.8	36.6	35.4	58.7	64.7	70.9	71.8	75.3	80.2
2040	80.8	76.6	59.5	48.4	38.5	25.1	60.6	69.2	72.0	73.9	80.7	83.9
2041	84.1	78.3	65.2	52.9	40.2	22.2	62.1	70.9	77.7	74.0	81.1	86.2
2042	87.9	83.1	68.3	51.1	39.2	22.8	69.4	75.0	82.2	79.8	85.1	89.5
2043	92.5	86.6	70.3	55.6	47.5	39.0	66.0	76.2	83.3	82.1	88.5	94.6
2044	99.3	93.3	73.8	60.1	48.6	33.1	73.8	81.4	90.1	87.9	97.1	102.5
2045	102.6	97.1	78.2	62.6	51.6	37.3	77.5	86.0	93.2	94.9	102.7	106.8
2046	116.2	107.5	94.8	69.7	66.7	40.4	85.6	97.6	108.1	101.6	112.6	117.4
2047	126.0	117.7	101.0	86.3	78.9	52.4	92.6	108.4	114.9	112.6	120.7	127.6
2048	131.2	124.3	105.8	91.3	80.0	68.4	101.0	113.3	120.6	118.5	126.4	135.4
2049	136.1	131.1	110.0	95.4	87.6	59.4	106.8	116.7	125.3	122.6	131.6	141.6
2050	142.9	135.6	118.3	99.0	82.2	73.8	109.7	123.7	128.9	129.3	139.9	148.4

TABLE H-5: AURORA monthly on-peak prices, Reference Gas, High CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.3	26.5	24.4	19.8	18.4	16.1	22.9	24.9	25.7	24.8	26.4	29.4
2021	29.1	29.6	23.6	21.1	19.1	18.7	24.3	26.4	28.4	27.1	29.9	32.2
2022	46.8	46.9	42.2	40.0	36.6	33.4	43.4	46.0	47.8	47.0	48.5	49.6
2023	50.4	50.3	45.2	42.3	40.1	39.1	45.5	48.7	50.5	50.3	52.6	55.0
2024	55.5	53.5	49.8	45.8	42.2	31.3	49.0	52.6	55.1	53.4	54.2	57.6
2025	56.9	56.5	50.6	47.7	45.8	39.5	52.3	54.5	56.9	56.5	62.3	66.7
2026	67.1	67.2	53.5	49.7	44.8	37.7	54.6	57.2	59.2	58.3	68.6	71.7
2027	70.8	71.4	53.9	50.8	47.2	36.9	55.3	59.0	61.0	60.5	70.8	73.8
2028	76.1	73.7	62.2	58.1	51.7	43.4	64.8	68.7	70.7	70.4	77.2	80.2
2029	82.6	79.1	70.2	63.6	60.4	45.1	70.1	75.4	77.8	74.4	79.7	84.5
2030	85.8	82.2	75.8	67.5	57.8	43.4	75.9	81.2	84.8	83.4	84.2	89.6
2031	91.0	87.6	78.7	70.2	65.6	53.5	80.4	86.8	90.0	88.6	89.1	94.1
2032	95.3	93.5	79.8	71.7	61.3	47.1	85.9	95.2	95.1	92.8	96.6	97.6
2033	102.5	100.4	83.4	72.5	58.6	60.8	89.2	97.1	99.8	98.5	102.5	106.0
2034	105.2	104.1	86.3	72.4	62.8	55.5	94.8	102.2	100.4	98.4	102.4	109.3
2035	110.3	105.7	89.1	74.8	58.0	44.7	100.3	110.8	109.3	100.3	102.0	110.5
2036	108.6	102.7	87.0	73.8	44.5	33.8	111.6	114.9	113.6	104.3	106.0	114.5
2037	112.5	111.4	92.8	78.7	60.6	58.5	111.2	128.4	128.5	110.5	114.4	118.4
2038	115.6	117.8	95.2	74.5	57.9	53.9	126.5	137.8	131.8	118.2	121.5	128.6
2039	122.0	122.9	97.2	77.7	60.7	61.3	136.1	149.6	145.6	125.5	125.9	129.3
2040	126.6	125.2	103.0	86.4	61.9	67.0	150.6	153.7	154.8	130.8	129.7	135.7
2041	135.9	133.6	110.5	98.4	80.4	46.7	145.7	164.5	167.2	142.6	141.0	142.6
2042	136.1	131.9	115.9	92.9	60.5	53.8	165.8	173.8	164.6	141.2	137.4	146.3
2043	137.0	139.0	106.6	95.2	69.8	76.9	170.3	186.7	184.8	148.9	143.0	153.0
2044	152.5	152.6	122.7	99.7	77.7	93.5	179.0	202.6	193.1	165.7	154.1	164.4
2045	161.8	161.3	129.3	118.1	82.6	96.4	182.9	199.7	187.4	160.2	168.4	175.9
2046	172.8	165.2	144.9	123.9	92.0	96.3	185.4	206.5	208.7	178.9	173.9	181.1
2047	174.8	173.3	147.8	125.2	101.4	98.2	203.8	205.8	198.5	173.9	178.5	190.0
2048	185.1	176.5	154.2	124.2	94.8	99.6	206.7	232.6	213.4	180.9	182.8	194.3
2049	188.9	186.9	152.7	141.0	100.9	122.8	238.8	252.2	239.6	201.4	190.8	198.7
2050	195.4	191.4	156.3	135.6	117.2	119.7	227.1	234.7	235.9	209.0	200.3	208.1

TABLE H-6: AURORA monthly off-peak prices, Reference Gas, High CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.4	23.1	18.2	16.0	14.2	20.1	22.2	23.7	23.7	24.5	26.5
2021	26.9	26.4	22.0	19.0	16.8	14.8	20.9	23.1	25.7	25.1	27.0	29.5
2022	45.1	43.8	40.4	38.0	31.6	30.2	39.7	41.9	44.3	44.7	46.4	47.2
2023	47.5	47.0	43.1	39.6	38.4	36.7	42.9	44.9	47.3	47.4	49.8	51.3
2024	51.4	49.8	47.4	44.2	40.7	29.4	45.6	49.1	50.9	49.9	51.3	53.4
2025	53.7	52.6	48.3	45.0	43.0	37.3	46.5	50.9	52.9	53.5	58.8	60.8
2026	64.0	63.0	51.0	48.7	42.9	31.8	50.1	53.5	55.7	55.0	63.3	65.9
2027	66.7	65.2	51.9	49.5	45.5	37.5	51.0	55.0	57.3	57.3	65.7	67.6
2028	71.8	70.2	60.3	56.5	51.7	40.7	61.0	64.5	66.2	65.9	72.8	74.0
2029	77.6	75.2	68.8	60.0	59.8	39.9	64.7	71.1	74.1	71.2	77.1	78.1
2030	82.5	80.1	74.4	65.3	58.6	42.2	72.7	78.0	80.4	79.9	82.3	83.4
2031	88.6	86.4	76.0	70.2	67.5	52.1	77.2	82.9	86.3	84.8	87.5	89.7
2032	93.5	90.9	80.4	71.9	53.1	43.9	84.7	86.7	91.7	88.8	93.7	94.7
2033	99.5	98.4	85.5	79.1	65.8	50.6	87.6	90.3	96.7	93.5	98.7	103.3
2034	102.5	101.8	87.9	81.1	62.6	45.5	94.2	97.0	100.9	98.5	105.4	104.0
2035	104.0	102.8	98.0	96.0	88.6	57.4	93.6	100.8	109.3	103.9	109.3	109.5
2036	113.2	111.0	101.0	91.7	71.0	50.7	95.0	101.5	112.7	108.5	115.8	114.1
2037	115.8	114.2	106.9	114.0	84.2	51.8	110.4	116.4	116.5	108.4	115.1	122.7
2038	128.4	124.8	122.7	124.9	74.2	50.8	116.9	122.3	129.8	114.5	120.8	124.3
2039	129.2	123.5	131.9	123.4	79.6	82.8	137.6	127.3	128.3	120.1	136.5	143.8
2040	142.0	134.1	129.8	127.7	99.3	69.1	133.4	137.1	134.4	143.5	157.6	156.5
2041	151.0	154.6	151.9	154.0	95.4	67.9	144.4	144.2	148.8	136.8	141.7	157.1
2042	160.3	159.2	140.5	141.8	100.4	71.0	140.3	142.3	155.6	158.6	162.9	166.4
2043	165.0	161.9	154.7	161.4	118.2	87.5	148.8	150.3	157.4	156.6	180.5	195.6
2044	177.4	169.3	151.1	160.6	103.1	84.1	180.6	169.9	166.4	158.7	190.1	183.5
2045	177.1	174.9	179.6	163.9	117.9	83.7	174.7	171.5	176.6	176.7	193.0	188.3
2046	176.4	167.3	174.2	153.1	146.1	85.2	195.5	191.6	188.3	168.8	180.7	193.5
2047	190.1	186.0	176.2	177.4	154.7	92.9	171.5	190.7	205.3	194.1	187.0	192.4
2048	190.3	196.7	180.5	177.0	128.5	117.1	190.6	193.0	196.5	198.3	193.0	208.7
2049	191.2	191.9	205.3	219.5	142.7	95.9	215.1	209.7	219.0	202.6	238.6	248.4
2050	215.4	201.4	192.3	192.7	126.0	116.3	227.2	216.8	216.2	191.9	218.9	223.3

TABLE H-7: AURORA monthly on-peak prices, High Gas, Reference CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.4	26.4	24.5	19.9	18.5	16.1	23.0	24.8	25.8	24.8	26.5	29.5
2021	41.0	41.7	33.1	29.0	25.7	25.4	33.8	36.8	39.3	37.5	41.8	45.1
2022	64.0	63.5	53.8	48.5	46.4	42.8	54.5	58.1	60.4	59.1	64.6	69.4
2023	70.6	70.1	59.4	53.5	50.1	49.6	60.1	64.7	66.8	66.1	75.9	81.1
2024	77.7	75.0	65.0	56.1	51.4	39.2	62.6	68.7	72.2	69.9	74.5	81.6
2025	80.9	79.9	65.1	57.0	54.5	48.0	66.4	70.2	74.3	71.3	88.4	98.8
2026	96.7	97.4	68.1	60.0	53.2	45.0	68.7	73.3	75.8	74.8	96.8	103.2
2027	102.8	103.3	68.6	61.7	56.7	45.4	70.2	75.9	78.1	76.7	98.7	105.8
2028	97.7	95.1	72.6	63.8	56.3	45.5	75.0	81.7	84.5	83.2	97.5	103.3
2029	103.5	99.4	79.7	69.7	65.0	45.3	79.3	87.5	92.3	86.7	97.7	104.8
2030	103.0	101.0	84.5	72.9	63.4	44.1	84.5	92.2	97.4	94.6	99.4	107.0
2031	113.3	111.2	91.6	77.6	74.2	59.1	92.6	102.2	106.3	102.4	107.6	116.3
2032	118.6	116.7	94.2	82.3	74.0	54.5	100.0	110.7	111.6	107.7	116.7	123.5
2033	123.5	122.4	97.4	86.1	74.7	72.4	103.9	112.9	115.5	112.8	121.5	127.5
2034	127.6	126.9	101.4	88.7	78.4	60.1	107.6	116.5	119.5	117.6	124.8	132.1
2035	134.9	129.9	106.3	89.9	84.1	56.7	107.2	119.4	123.6	120.4	126.9	136.9
2036	137.3	133.2	110.0	94.1	74.6	46.4	113.8	121.6	129.6	126.3	131.6	143.1
2037	142.4	142.4	114.6	96.1	91.0	73.3	117.5	129.2	135.8	131.1	138.9	148.7
2038	147.2	148.2	120.0	100.9	82.5	63.5	127.6	139.6	141.2	138.1	145.8	154.8
2039	157.0	155.6	125.6	107.7	96.3	78.1	138.5	145.7	147.4	141.7	153.3	161.7
2040	162.9	160.7	129.9	114.8	95.5	72.1	141.4	151.5	158.0	152.6	161.7	168.6
2041	172.1	167.8	138.1	122.4	114.8	61.3	147.2	156.5	163.8	156.9	163.6	174.8
2042	178.6	174.2	145.8	129.3	98.1	60.5	158.4	174.3	173.1	162.4	168.1	181.0
2043	182.5	181.6	150.8	130.9	111.7	95.9	162.0	172.8	178.6	169.8	178.5	193.1
2044	197.1	193.9	163.6	139.1	120.0	111.5	174.3	188.5	189.5	184.7	192.3	202.3
2045	205.3	204.6	170.0	151.3	131.3	110.4	188.8	199.2	200.7	191.1	200.2	210.2
2046	218.8	212.0	180.8	159.0	134.6	118.0	189.6	207.3	212.0	202.1	209.9	221.4
2047	224.4	219.4	189.9	170.8	146.8	119.8	198.0	214.4	221.7	209.9	216.8	231.6
2048	232.5	225.4	194.3	167.7	135.7	113.3	208.2	219.4	223.1	214.1	223.2	239.7
2049	239.3	238.2	200.5	175.7	158.8	138.5	221.2	229.8	234.1	224.3	234.4	249.4
2050	247.8	247.0	206.7	188.1	172.4	139.0	226.5	240.8	243.7	231.8	245.9	256.3

TABLE H-8: AURORA monthly off-peak prices, High Gas, Reference CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.6	23.0	18.3	16.0	14.3	20.1	22.1	23.7	23.6	24.5	26.4
2021	38.0	37.0	30.2	25.6	22.6	20.1	29.2	32.0	35.2	34.2	37.4	41.4
2022	60.3	57.9	51.1	45.1	38.8	37.4	48.4	52.7	55.8	55.9	60.2	64.1
2023	65.4	63.5	55.7	48.9	46.3	44.0	54.4	58.7	61.5	60.9	70.0	73.5
2024	70.6	66.2	60.2	52.4	47.7	35.2	55.7	62.8	64.7	62.6	69.1	74.7
2025	74.8	72.0	59.8	53.3	48.8	44.3	57.2	64.6	67.6	65.8	81.5	89.2
2026	90.8	90.3	62.7	57.2	50.2	37.7	61.2	67.9	70.5	68.1	88.3	94.5
2027	96.1	92.3	63.6	57.8	52.8	42.7	62.3	69.5	72.3	71.3	91.1	96.5
2028	90.7	88.6	68.7	60.1	54.6	43.1	69.0	75.8	77.9	77.0	91.3	94.7
2029	95.3	92.4	77.1	64.8	62.7	41.0	71.4	81.6	86.0	82.2	92.0	96.8
2030	97.2	95.3	81.5	69.1	63.8	44.5	79.1	86.5	90.9	89.5	95.7	98.7
2031	107.8	106.1	85.9	77.4	74.5	58.1	86.7	95.6	99.5	97.4	103.8	107.5
2032	113.9	110.4	93.6	80.9	65.7	52.1	95.9	99.4	104.8	102.3	111.1	115.9
2033	117.8	115.7	96.3	84.6	77.6	64.2	99.1	104.3	110.2	106.1	115.5	121.3
2034	122.1	119.4	99.2	84.0	74.2	56.6	99.2	108.6	113.4	111.3	121.5	125.2
2035	126.4	124.6	106.2	93.3	83.9	72.3	100.7	114.4	118.2	112.6	123.3	127.2
2036	135.3	129.8	109.9	94.9	84.2	54.3	103.8	115.4	122.7	117.6	131.0	136.0
2037	139.0	136.8	113.9	101.6	91.6	66.7	110.8	122.6	128.4	124.8	135.7	140.7
2038	145.5	143.5	121.8	115.9	86.4	60.9	115.9	127.7	133.9	128.1	139.2	144.6
2039	149.5	150.2	126.3	121.7	95.2	95.0	134.5	136.9	144.1	142.1	151.8	152.3
2040	156.4	156.0	132.4	118.5	98.4	77.4	130.6	142.8	145.7	147.8	158.8	163.1
2041	165.9	161.4	146.5	138.1	110.2	75.8	140.3	151.5	166.5	158.2	170.0	167.6
2042	171.1	168.0	153.8	132.4	109.7	82.7	156.5	163.2	172.7	168.9	177.3	178.6
2043	182.5	176.6	154.6	145.8	128.5	106.2	145.4	165.1	174.6	168.8	173.2	182.2
2044	187.5	185.4	160.6	148.9	124.8	97.6	180.6	177.7	186.9	176.4	189.0	193.5
2045	198.0	197.6	170.3	164.7	147.5	106.0	187.9	192.4	202.4	201.0	212.6	219.1
2046	212.7	208.3	183.4	175.1	150.6	106.5	186.5	201.9	217.1	197.7	205.0	214.1
2047	220.4	214.0	186.7	171.1	152.2	118.3	189.6	204.8	208.4	202.4	214.8	223.2
2048	225.6	220.3	199.0	181.3	164.8	138.1	197.3	221.5	230.9	219.3	226.2	232.3
2049	229.6	229.7	202.8	193.4	167.0	127.4	207.1	222.0	234.2	223.1	228.9	238.6
2050	240.0	238.1	217.9	201.3	155.0	160.7	213.5	232.8	238.3	239.9	254.3	255.4

TABLE H-9: AURORA monthly on-peak prices, High Gas, No CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.4	26.4	24.5	19.9	18.5	16.1	23.0	24.8	25.8	24.8	26.5	29.5
2021	41.0	41.7	33.1	29.0	25.7	25.4	33.8	36.8	39.3	37.5	41.8	45.1
2022	55.2	53.6	43.5	37.9	34.4	28.8	43.9	48.1	50.8	49.5	55.2	61.8
2023	62.1	59.8	49.1	43.6	38.5	36.6	50.6	54.9	59.2	55.9	68.3	74.5
2024	72.6	68.4	57.6	47.9	42.0	29.2	55.1	61.1	67.1	63.3	69.0	76.4
2025	74.7	72.4	56.1	46.3	44.3	36.1	58.0	61.5	68.8	63.0	81.9	92.6
2026	87.8	86.2	56.5	47.4	38.8	31.4	57.1	61.4	64.3	63.0	85.6	91.7
2027	93.5	90.9	55.9	47.9	41.6	30.4	57.7	63.7	65.7	64.6	86.9	93.6
2028	86.9	82.8	59.2	48.5	40.6	32.5	62.4	68.8	71.7	70.4	84.9	90.7
2029	91.9	86.2	64.8	52.3	47.5	29.2	66.3	74.1	78.6	73.5	84.9	91.9
2030	90.5	88.1	70.0	56.3	46.9	29.7	70.9	78.2	83.5	81.1	86.1	93.7
2031	98.4	95.5	75.5	58.8	56.7	39.8	76.8	85.8	89.9	87.1	92.8	100.6
2032	101.8	99.5	76.5	60.6	51.8	36.0	81.9	93.1	93.9	89.8	99.4	105.4
2033	104.8	103.8	77.3	59.7	49.5	45.2	83.3	91.9	95.2	93.1	102.2	107.6
2034	108.9	106.3	79.4	61.2	52.6	38.0	86.2	93.3	97.4	96.4	103.8	111.1
2035	112.6	106.6	81.9	59.9	54.9	31.4	84.8	95.4	99.5	97.0	105.5	113.8
2036	113.5	108.0	82.0	63.2	45.3	24.4	87.8	96.3	102.8	101.1	107.2	117.3
2037	117.3	115.7	87.1	61.1	58.0	46.2	90.1	101.5	109.0	105.2	113.2	122.9
2038	121.6	121.7	90.2	62.5	53.1	35.4	98.9	109.2	114.2	111.9	120.6	129.2
2039	130.3	126.2	93.5	68.6	62.6	42.7	103.3	112.7	117.7	113.6	125.6	134.0
2040	135.1	129.8	94.8	77.4	53.9	36.1	107.0	116.0	123.1	121.2	130.4	138.7
2041	140.5	134.8	103.8	75.9	79.0	29.0	105.0	120.6	127.0	123.4	132.9	145.1
2042	145.4	140.3	109.4	86.1	64.1	29.5	116.1	128.5	133.0	130.4	137.1	150.0
2043	151.9	146.8	110.6	83.3	73.6	54.1	117.9	130.1	139.8	135.0	143.4	158.4
2044	164.0	154.8	119.9	95.1	77.5	64.7	128.1	144.1	148.7	146.9	154.3	167.1
2045	169.4	163.6	125.2	102.7	89.8	70.5	133.6	148.7	154.3	151.5	161.6	174.2
2046	191.2	179.7	148.5	120.3	104.5	73.2	150.6	167.7	177.8	168.0	177.0	192.5
2047	210.0	200.3	170.9	143.2	131.3	91.2	168.8	182.7	190.5	186.5	195.7	215.2
2048	221.9	209.8	176.4	153.6	130.1	95.2	176.6	190.5	201.1	195.9	209.2	225.4
2049	227.9	221.0	186.3	162.1	144.7	115.5	186.4	200.7	209.8	207.1	218.3	234.7
2050	238.3	231.0	193.2	167.1	157.7	113.8	192.1	210.3	217.2	214.4	228.4	245.4

TABLE H-10: AURORA monthly off-peak prices, High Gas, No CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.6	23.0	18.3	16.0	14.3	20.1	22.1	23.7	23.6	24.5	26.4
2021	38.0	37.0	30.2	25.6	22.6	20.1	29.2	32.0	35.2	34.2	37.4	41.4
2022	50.7	48.2	40.8	33.5	26.7	22.2	38.5	42.5	45.9	46.0	50.4	57.1
2023	57.1	53.9	44.8	37.3	34.4	30.1	44.7	49.8	52.7	51.1	61.4	68.2
2024	65.1	60.4	52.8	44.0	39.7	25.1	48.9	56.7	59.5	56.2	63.9	69.8
2025	68.8	64.3	52.0	42.0	37.7	31.0	49.5	57.3	60.8	58.1	75.8	83.9
2026	81.7	79.0	50.2	44.8	35.6	23.8	50.2	56.4	58.9	56.7	77.2	83.3
2027	86.4	81.4	51.1	44.4	37.1	27.7	51.0	57.8	60.1	59.5	79.7	85.0
2028	80.9	76.6	54.8	45.8	40.0	30.1	56.7	63.5	65.2	64.4	78.7	82.8
2029	83.7	79.4	63.1	48.1	46.0	26.3	58.9	68.4	72.8	69.5	79.2	83.7
2030	84.7	81.9	68.5	53.4	48.3	29.3	66.0	73.0	77.6	76.4	82.0	84.9
2031	92.7	90.3	70.4	60.3	58.7	42.2	71.5	80.1	84.2	82.1	87.9	92.0
2032	97.1	92.5	75.4	59.8	44.5	34.1	78.9	82.4	87.5	84.7	93.8	98.6
2033	100.6	95.5	77.3	61.4	53.4	40.4	78.2	84.2	89.8	87.2	95.9	101.6
2034	101.6	98.7	76.5	59.0	51.5	33.5	79.8	87.2	91.3	90.1	99.8	103.6
2035	103.9	101.4	84.7	63.4	59.7	46.2	79.9	91.0	95.1	90.8	100.5	104.6
2036	109.7	104.3	83.4	67.4	57.4	31.6	80.1	90.1	97.7	93.1	104.7	109.8
2037	111.8	110.4	86.4	71.0	63.2	40.7	85.1	97.7	101.4	99.1	108.8	114.1
2038	118.0	115.0	95.1	74.8	56.9	37.4	88.5	99.4	105.2	102.9	112.3	119.6
2039	125.0	119.3	96.5	82.6	62.8	57.7	97.5	104.0	110.1	112.9	120.1	125.7
2040	128.4	124.4	98.0	86.6	63.8	47.4	97.1	110.1	111.9	113.9	124.7	130.8
2041	132.8	126.8	107.8	83.9	68.5	41.2	104.3	113.9	124.1	118.2	127.4	133.6
2042	139.6	134.5	111.2	85.3	67.7	42.1	114.7	121.3	129.3	125.0	133.6	141.7
2043	148.0	139.9	114.0	90.4	81.2	68.3	108.2	122.9	131.2	128.9	138.7	147.8
2044	157.4	148.4	118.9	98.5	81.8	59.2	123.3	130.5	138.6	136.2	150.5	157.6
2045	162.5	154.6	125.8	106.5	87.7	65.0	128.9	137.5	145.6	145.7	157.7	164.9
2046	182.8	171.6	151.5	112.1	109.4	74.2	143.5	153.8	167.6	159.6	176.3	182.9
2047	203.3	195.8	166.2	145.9	133.6	95.3	156.2	176.0	183.7	181.4	195.5	204.7
2048	214.6	206.1	176.1	156.0	139.0	116.0	172.6	186.7	193.8	191.5	206.3	219.0
2049	223.2	218.0	185.1	164.7	150.8	105.5	179.2	194.3	202.3	199.6	214.6	228.8
2050	232.3	224.2	195.1	172.9	140.8	125.3	184.6	203.5	210.2	211.4	227.4	240.6

TABLE H-11: AURORA monthly on-peak prices, High Gas, High CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	24.2	22.6	21.5	18.0	17.6	16.2	20.5	22.3	23.1	22.7	24.4	26.1
2018	24.9	23.9	23.0	18.3	16.8	14.2	20.9	23.1	24.2	22.9	24.0	26.6
2019	26.5	25.2	24.2	19.3	18.3	16.2	22.2	23.9	25.2	23.6	25.1	28.0
2020	27.3	26.5	24.4	19.8	18.4	16.1	22.9	24.9	25.7	24.8	26.4	29.4
2021	40.9	41.7	33.0	28.9	25.5	25.2	33.7	36.7	39.1	37.5	41.7	45.0
2022	67.4	66.4	57.4	52.1	49.6	47.0	57.6	61.5	63.6	62.3	68.2	72.4
2023	73.9	73.4	62.9	57.1	53.7	52.9	63.5	67.9	70.3	70.0	78.9	83.9
2024	80.6	78.2	68.4	59.7	55.6	42.2	66.2	72.0	75.8	73.5	78.0	84.9
2025	83.7	83.4	69.0	61.2	59.1	51.8	70.2	74.1	78.1	75.1	92.0	101.5
2026	100.1	100.1	72.1	64.0	57.6	49.3	73.1	77.5	80.0	78.8	100.5	106.0
2027	105.7	106.3	72.5	66.2	60.9	50.0	74.4	80.5	82.5	81.1	102.4	109.2
2028	102.9	101.2	79.0	70.8	64.3	55.5	82.7	88.8	91.1	89.9	103.8	109.4
2029	111.5	106.7	88.8	78.7	74.7	57.8	89.4	96.7	101.3	95.3	105.4	112.8
2030	112.0	110.0	94.9	84.7	74.2	55.8	94.7	103.1	108.1	104.0	108.1	116.4
2031	120.8	119.7	100.4	88.9	84.6	69.8	102.3	112.5	115.8	110.9	115.8	124.9
2032	126.3	125.9	103.4	93.0	79.9	62.4	114.5	122.3	123.5	117.2	124.8	132.0
2033	131.6	131.4	108.4	91.1	76.6	77.4	115.0	123.6	125.7	123.0	131.2	137.0
2034	137.1	136.9	110.7	92.3	82.6	73.8	120.4	128.7	127.0	124.9	132.9	141.7
2035	144.8	137.9	112.8	96.2	71.8	58.9	129.2	144.7	141.3	127.6	132.0	141.8
2036	142.1	134.7	111.8	92.2	61.9	48.5	142.5	155.8	150.2	134.8	135.6	148.1
2037	147.5	146.8	115.7	97.4	76.7	74.2	140.9	163.7	162.7	143.3	145.0	153.6
2038	151.7	154.4	122.8	104.3	80.5	72.1	159.8	177.9	170.0	152.5	155.0	163.3
2039	159.5	158.7	125.7	104.3	83.8	82.7	173.1	193.0	182.3	153.8	156.0	168.3
2040	166.5	164.5	131.0	114.0	78.5	84.5	196.3	193.8	184.4	162.3	164.2	174.9
2041	175.6	175.0	142.4	123.3	104.5	62.3	180.9	199.5	200.4	173.0	174.6	184.1
2042	181.1	179.2	141.9	118.9	86.6	72.4	207.0	230.6	210.4	178.5	182.8	188.6
2043	180.3	189.6	139.2	124.7	89.4	103.4	221.4	248.4	229.6	182.1	184.9	204.6
2044	200.6	203.0	154.5	131.7	106.3	127.4	233.1	259.4	247.7	211.4	199.9	211.0
2045	211.4	210.0	162.0	147.9	107.0	131.5	239.8	252.4	231.9	202.8	218.8	231.7
2046	228.1	218.8	188.9	159.8	128.1	126.6	243.7	272.3	267.9	233.3	225.8	234.7
2047	230.2	227.4	191.5	167.7	134.3	130.4	261.0	254.3	250.3	223.6	228.6	251.9
2048	246.9	230.7	198.4	152.4	124.0	132.4	270.4	291.3	276.3	233.4	240.6	254.0
2049	246.6	246.3	190.4	176.2	133.3	151.0	306.4	315.1	291.7	242.9	246.7	268.3
2050	257.2	253.1	202.1	173.4	158.1	153.9	293.9	312.8	282.3	254.5	259.4	273.2

TABLE H-12: AURORA monthly off-peak prices, High Gas, High CO_2 Price (nominal $/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	22.1	21.0	20.2	16.4	15.3	13.3	17.5	19.3	21.1	21.8	22.8	24.0
2018	22.8	21.4	21.8	16.2	14.9	10.8	17.5	19.7	21.7	21.4	22.4	23.9
2019	23.9	22.8	22.1	17.6	16.4	13.2	18.6	21.0	22.6	22.5	23.3	25.3
2020	24.7	23.4	23.1	18.2	16.0	14.2	20.1	22.2	23.7	23.7	24.5	26.5
2021	37.8	36.9	30.2	25.6	22.5	20.0	29.1	32.1	35.3	34.1	37.4	41.4
2022	64.3	61.4	54.4	49.0	42.1	40.6	52.0	56.0	59.2	59.2	63.3	67.2
2023	67.9	67.1	59.1	52.7	50.3	48.1	58.0	62.2	64.8	64.4	73.2	76.5
2024	73.0	69.8	63.9	56.6	52.1	38.8	58.9	66.0	68.1	66.2	72.3	77.8
2025	77.5	75.5	64.0	57.4	53.7	48.4	60.7	68.5	71.4	69.6	84.4	92.3
2026	93.9	93.9	66.6	61.6	54.7	41.6	65.0	71.8	74.7	72.1	91.6	98.0
2027	97.9	96.2	67.8	62.5	57.4	48.1	66.0	73.6	76.5	75.2	95.2	99.9
2028	95.9	94.9	75.8	67.4	62.6	50.6	75.8	82.6	84.5	83.5	97.6	100.4
2029	103.6	100.9	85.5	73.8	71.8	51.6	79.6	90.8	94.8	89.9	100.5	103.9
2030	107.7	104.9	92.3	80.8	75.3	53.3	88.5	97.1	101.3	98.0	105.7	107.6
2031	117.0	114.1	95.4	89.2	83.5	69.3	95.1	105.8	109.6	105.3	112.3	117.0
2032	122.3	119.5	104.5	93.0	72.1	62.6	110.6	112.0	114.7	110.5	120.0	126.7
2033	126.6	125.8	109.0	99.7	85.0	65.8	108.2	111.5	119.6	114.5	125.0	132.1
2034	131.9	129.8	114.5	105.1	82.7	60.7	114.6	120.0	127.7	126.5	137.2	137.1
2035	130.2	131.5	124.5	126.3	114.3	75.1	119.8	125.7	134.4	133.1	140.4	138.5
2036	146.6	145.3	134.9	121.4	95.6	66.1	126.2	128.2	135.1	132.4	151.7	149.5
2037	153.8	153.3	137.1	144.3	105.8	69.4	141.8	146.9	145.6	136.5	149.3	159.4
2038	162.1	161.6	155.7	153.7	95.4	67.8	148.8	157.5	159.0	140.3	153.8	165.3
2039	168.6	162.2	151.7	154.4	100.7	113.0	181.5	161.4	164.0	158.5	173.2	173.3
2040	173.9	174.6	162.3	165.7	123.3	91.5	163.6	166.5	172.7	182.2	204.5	205.1
2041	202.6	193.7	183.8	194.7	118.4	88.6	164.6	167.8	176.0	177.2	204.6	215.0
2042	216.6	203.6	190.4	179.2	137.3	96.1	186.2	177.3	189.8	194.0	207.5	231.6
2043	233.0	226.8	203.6	222.4	158.0	114.9	182.6	187.9	204.6	212.4	227.4	250.8
2044	223.9	212.2	190.7	203.0	135.7	113.0	240.5	211.7	211.4	196.0	233.8	239.6
2045	236.4	228.9	219.8	213.9	156.5	107.8	224.1	219.0	227.3	225.2	240.8	240.0
2046	230.9	220.6	226.1	205.2	194.1	115.1	255.2	249.4	235.1	213.5	231.2	249.9
2047	254.8	246.6	219.6	233.1	203.9	121.7	208.8	240.6	268.1	247.6	254.1	245.0
2048	248.5	269.1	250.3	237.2	172.4	161.7	244.1	244.8	249.8	246.3	254.9	278.9
2049	261.5	256.9	248.0	272.6	176.9	123.5	270.6	261.2	274.2	252.1	307.0	291.6
2050	266.8	267.2	250.4	252.1	166.1	157.7	278.5	266.7	279.5	261.3	291.2	306.2

APPENDIX I. Demand Response Programs

PGE targets DR programs that provide firm, cost-effective capacity that addresses the conditions specific to the Company's service territory. PGE is endeavoring to go beyond DR that is primarily about maintaining reliability during infrequent peaking events or generation outage events to DR that is fast-acting and flexible, and preferably automated. The Company's DR programs include strict specifications designed to meet both types of needs. These specifications also help create programs with greater certainty during curtailment events.

Currently, PGE calls DR events based on criteria related to load, weather and wind forecasts, and market conditions. Reasons for calling events may include, but are not limited to:

- Energy load forecasted to be in the top one percent of annual load hours;
- Forecasted temperature above 90 or below 32;
- Expected high generation heat rates and market power prices; and/or
- Forecasted low or transitioning wind generation.

In light of this DR context, PGE views direct load control (DLC) as the best alternative for future DR potential. The Company also considers firm and fast-responding programs as more valuable. The following sections describe PGE's firm and non-firm demand response programs in more detail.

I.1 Firm Demand Response Programs

PGE currently has three firm demand response programs in operation:

Schedule 77 Curtailment Tariff

- Eligible population: large nonresidential customers (>200 kW)
- Started: July 2009
- Nominated Load (as of April 2016): 1.8 MW

Energy Partner^{SM} ADR pilot

- Eligible population: medium and large nonresidential customers (>30 kW)
- Started: August 2013
- Nominated Load (as of April 2016): 11.2 MW

Rush Hour Rewards smart thermostat pilot

- Eligible population: residential customers with a Nest thermostat
- Started: November 2015
- Expected Load (as of April 2016): 0.4 MW.

I.1.1 Schedule 77

PGE currently has 1.8 MW participating and available for curtailment in its Schedule 77, Firm Load Reduction Program. The program experienced a large drop in nominated load as its primary customer, a large paper manufacturer representing 16 MW, went out of business. Despite this setback, PGE will continue to pursue new customers. Feedback from our third-party evaluator for the Energy Partner^{SM} program indicates that customers struggling or disqualified from that program may be better suited for Schedule 77.

I.1.1.1 Schedule 77: Demand Response Events

This tariff is callable up to 48 hours per year. As shown in Table I-1, PGE offers customers three options for participation: summer only, winter only, or both seasons:

TABLE I-1: Schedule 77 customer participation options

Customer Option	Participation Months	Number of Months Participating
1	Dec, Jan, Feb, Jul, Aug, Sep	Six-month – all months
2	Jul, Aug, Sep	Three-month seasonal – summer
3	Dec, Jan, Feb	Three-month seasonal – winter

PGE also offers customers two firm load reduction options. Option A provides four-hours advance notice to the customer to reduce load. Option B provides 18 hour notice. With each option, the called event's duration is four consecutive hours per day.

TABLE I-2: Schedule 77 firm load reduction options for customers

Customer Option	Advance Notification Hours	Event Duration Consecutive Hours per Day	Reservation Payment per kW
A	4	4	\$6.00
B	18	4	\$3.00

I.1.2 Energy Partner^{SM}

PGE's Automated Demand Response (ADR) program, known as Energy Partner^{SM}, enables participants to receive payments for reducing electricity consumption during peak usage periods. PGE may call program events at its discretion. Program events typically coincide with peak demand on the electric grid (e.g., hot summer or cold winter days). EnerNOC Inc. (EnerNOC), a third-party aggregator, operates the program and is responsible for program implementation. This includes recruiting eligible large non-residential PGE customers, installing curtailment hardware and software, and providing financial settlement services. The program is currently in the pilot stage.

Eligible customers include large non-residential customers on the following rate schedules:

- Schedule 89 – Large Nonresidential Standard Service (> 1,000 kW)
- Schedule 85 – Large Nonresidential Standard Service (>201 and <1001 kW)
- Schedule 83 – Large Nonresidential Standard Service (>30 and <200 kW)

- Schedule 49 – Large Nonresidential Irrigation and Drainage Pumping
- Schedule 47 – Small Nonresidential Irrigation and Drainage Pumping.

I.1.2.1 Energy Partner^{SM}: Demand Response Events

The program runs for two three-month periods in summer and in winter, starting in summer 2013. The summer period runs from July 1 through September 30. The winter period runs from December 1 through the last day of February ("winter period").

Energy Partner^{SM} event dispatch is limited to:

- Weekdays (excluding Western Electricity Coordinating Council holidays)
- One-hour blocks (between one and five hours)
- Up to 15 times per season
- No more than two consecutive days
- No more than 40 hours per season.

PGE provides EnerNOC with not less than 10-minute dispatch notice through a direct connection between EnerNOC's systems and PGE's Command Center. PGE can request load reduction in any time period during which Energy Partner^{SM} allows dispatch.

Some common energy shifting and curtailment strategies include, but are not limited to:

- Temporarily shifting noncritical production processes by a few hours;
- Shifting HVAC set points for a short period of time;
- Adjusting variable frequency drives on pumps or motors for a short period of time.

The amount that a customer is paid depends on the level of participation relative to their nominated demand and varies according to how much energy is shifted and the frequency of events. The customer may override an event at no penalty, but participation is required to receive an incentive.

I.1.2.2 Energy Partner^{SM}: Pilot Evaluation

As part of the pilot rollout, PGE contracted with a third party evaluator to assess the demand impacts, customer experience, and overall program implementation process for Energy Partner^{SM}. The contractor produced two evaluation reports, a preliminary report in April 2015[234] and the final report in April 2016.[235]

Since the program's launch, PGE has continually made program improvements based on customer feedback, discussions with EnerNOC, and the results of evaluation studies. Over the course of the program's first five seasons, the evaluator identified the following improvements:

- A removal of bottlenecks in the commissioning process, leading to a reduction in the timeframe required for enablement.

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[234] See Docket RE 126, PGE's Automated Demand Response Phase I Report, filed April 15, 2015.

[235] See Docket RE 126, PGE's Automated Demand Response Phase II Report, filed April 28, 2016.

- PGE now provides a list of preselected customers to EnerNOC based on a blind pull of customer load profiles.
- The solicitation of dispatchable standby generation (DSG) customers to participate in the program.
- PGE incentivizes Key Customer Managers (KCMs) for the enrollment of large end-users.
- Customers now receive notification to view performance 48 hours after an event.
- Customers receive their incentive payment faster, due to a reduction in the time required to process invoices.
- A revision in the payment formula, which now provides greater incentives by rewarding customers for providing capacity rather than hourly performance.

As the program continues to mature, there are still potential opportunities for further improvement. The third-party evaluator identified the following improvements and PGE has already taken steps to implement many of these suggested changes:

- Reach out to customers who have already declined participation.
- Coordinate with Energy Trust of Oregon.
- Expand enrollment to also include customers who can only participate in some program hours.
- Leverage Advanced Metering Infrastructure (AMI) data to reach potential participants.
- Fine-tune customer messaging.
- Develop strategic partnerships with control companies and engineering firms.

PGE continues to receive feedback from the evaluator and will implement further improvements as appropriate.

I.1.3 Rush Hour Rewards

The Rush Hour Rewards smart thermostat pilot tests the value of DR using a programmable communicating thermostat already installed in customer homes. This bring-your-own-thermostat (BYOT) design allows for significant capacity benefits without the cost of installing and maintaining customer equipment. The program also builds on the Energy Trust investments in this field.

The specific objectives for the program are:

- Use residential programmable communicating (“smart”) thermostats for automated demand response under a BYOT structure.
- Conduct a two-year pilot targeting up to 5,000 customers.
- Focus on the summer season due to a stronger likelihood of having controllable systems.
- Provide participants signup payments as well as seasonal incentive payments.
- Demonstrate measurable savings of between 0.8 kW and 1.2 kW during events.

- Enable a built-to-scale program that does not depend upon PGE's new Customer Engagement Transformation (CET) system.

I.1.3.1 Rush Hour Rewards: Demand Response Events

PGE can call DR events during the months of June, July, August, September, December, January, and February.

For the pilot, PGE further limited Rush Hour Rewards dispatch to:

- No DLC events on weekends or holidays.
- No more than one event per day.
- No more than two days in succession.
- No fewer than six and no more than ten events per season.

PGE will notify customers by 7:00 p.m. the day ahead for morning events and a minimum of two hours prior to an afternoon event.

Customers will receive notification of events via their mobile application, and on the thermostat. Customers may use their mobile device or their thermostat to elect not to participate in an event.

During events, the system will implement the curtailment measure learned to work best for a customer's household. These measures include letting temperature ranges float-up during events, cycling air-conditioning, and/or precooling. Customers can opt-out at any time. No other effort is required by the customer.

Customers receive a $25 reward for signing up for the program and $25 per season for participation in events. PGE will monitor customer participation. Customers who fail to participate in at least 50 percent of the events will not receive their season payment.

The cost of this pilot is between the cost of PGE's other commercial DR programs. The expected performance is one kW per event.

I.1.3.2 Rush Hour Rewards: Pilot Evaluation

PGE contracted with a third-party evaluator to assess program impacts, customer experience, and the implementation process. The evaluator will provide ongoing evaluation, measurement, and verification throughout the program. The evaluator will also provide full process and impact evaluation reports at the end of program year one and at the completion of the pilot.

For the impact evaluation, the evaluator will estimate demand impacts econometrically using historical data from participants. This analysis will estimate both event period impacts as well as impacts in hours just before and after events to determine any possible rebound effects. The evaluation will also track opt-out rates for each event.

PGE will measure customer satisfaction through surveys at the end of each season to ensure that customers are happy with their experience. The Company will correct any identified problems on an ongoing basis.

It is PGE's expectation that there will be checkpoints six months after each summer season, as has occurred in the Flex Price^{SM} and Energy Partner^{SM} Pilots.

I.1.4 Smart Water Heaters

PGE is strongly interested in the success of water heater direct load control (DLC). Currently, the Company has significant penetration of electric water heaters in its service territory. Water heaters represent an important demand resource for PGE, because the Company is able to control them with minimal impact to the customer. Water heaters are particularly appealing, because they effectively act as a thermal battery and, therefore, have a much wider array of use cases than more traditional resources.

PGE believes appliance market transformation has the potential to create the greatest DR capacity among residential customers, due to its ease of use by customers with either DLC or with dynamic pricing. Other appliances could also provide DR through DLC, including heating, ventilation, and air conditioning systems (HVAC systems) via thermostats, electric spas, and electric vehicle chargers. If customers had one of the previously mentioned primary appliances, secondary appliances such as dryers, dishwashers, refrigerators, or stand-alone freezers could provide additional DR. The secondary appliances, however, only become cost-effective in a market where DLC on "market-transformed" primary appliances is relatively mature and common place.

PGE is working actively with NEEA and BPA to push forward on market transformation efforts for grid-interactive water heaters using the ANSI/CTA-2045 standard. This standard specifies a modular communications interface (MCI) to facilitate communications with residential devices for applications such as energy management. The MCI provides a standard interface for energy management signals and messages to reach devices. Such devices may include an energy management hub, an energy management controller, an energy management agent, a residential gateway, an energy services interface, a sensor, a thermostat, an appliance, or other consumer products.

Although the market has made significant progress in establishing a standard interface socket for "smart" appliances, two difficult tasks still remain:

- Incorporation of the socket on appliances so that consumers, region- or nation-wide, can automatically replace old/obsolete appliances with "smart" appliances.
- Establishment of standard communication protocols. Upon adoption of the socket, the normal replacement cycle and new construction will allow an increasing share of water heaters to become DR-compatible.

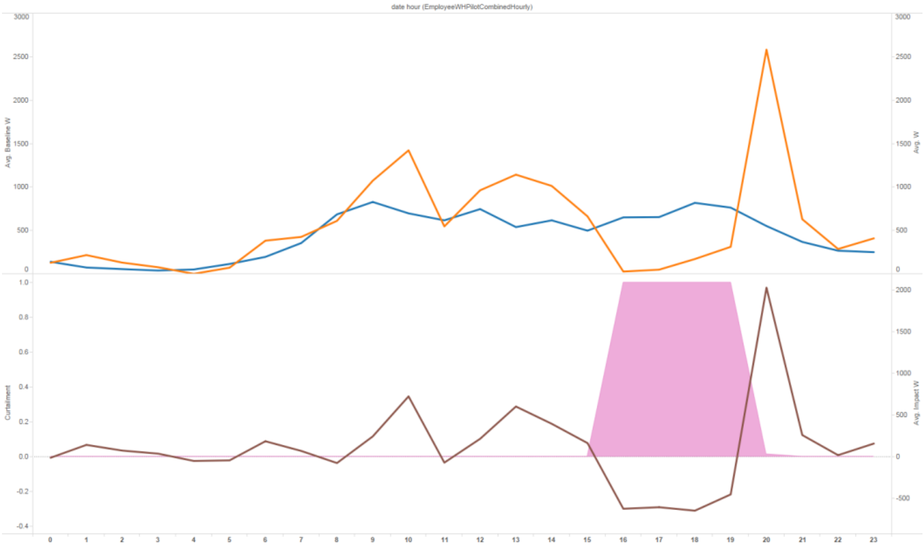
PGE is participating in the region-wide demonstration of ANSI/CTA-2045 standards. This pilot will involve a number of utilities across the region enabling the use of water heaters for peak shaving, frequency regulation, and renewables firming. This pilot began in 2016 and will run through 2018.

I.1.4.1 Employee Smart Water Heater Pilot

PGE is currently conducting an employee pilot of smart water heater DLC. This pilot utilizes the CTA-2045 standard to control 14 resistance water heaters in employees' homes. Load control began in November 2015 and has been operating near continuously since then, over all hours and days. This differs from typical demand response, where PGE only calls events in times of critical need.

Figure I-1 below shows an example event from this pilot. The orange line shows the actual average load of all employees over the day and the blue line shows the typical load for that day. The pink bars indicate when a shed event occurred and the maroon link indicates the load impact (difference between the orange and blue lines).

FIGURE I-1: Example event from employee water heater pilot



While the pilot is still in its infancy, PGE is gathering information about "smart, always-on" DR. Observed demand impacts are within the range of typical DLC programs, despite running at all times. The Company has seen an average demand impact of 0.3 kW across all periods. During the one critical event day this past winter, PGE observed a 0.5 kW impact.

As PGE presented at the 2016 ACEEE Hot Water Forum, the following lessons learned will help guide the Company's efforts to scale up a mass-market program:

- Post-event duty cycling is an effective means to mitigate rebound effects.[236]
- Segmentation of hot water use patterns could lead to better targeting of curtailment strategies. That is, different customers may be better.
- Program designs should consider deployment strategies that ensure reliable transmission of meter data to the utility.
- Additional analytics may make it easier to ascertain when loss service will occur.

I.1.4.2 Mass-Market Water Heater DLC

Concurrently with the smart water heater pilot, PGE will begin developing a mass market water heater program in 2017. This program will focus on peak shaving primarily, but will, where possible, look to technologies that enable other use cases. PGE anticipates that the program will look at both

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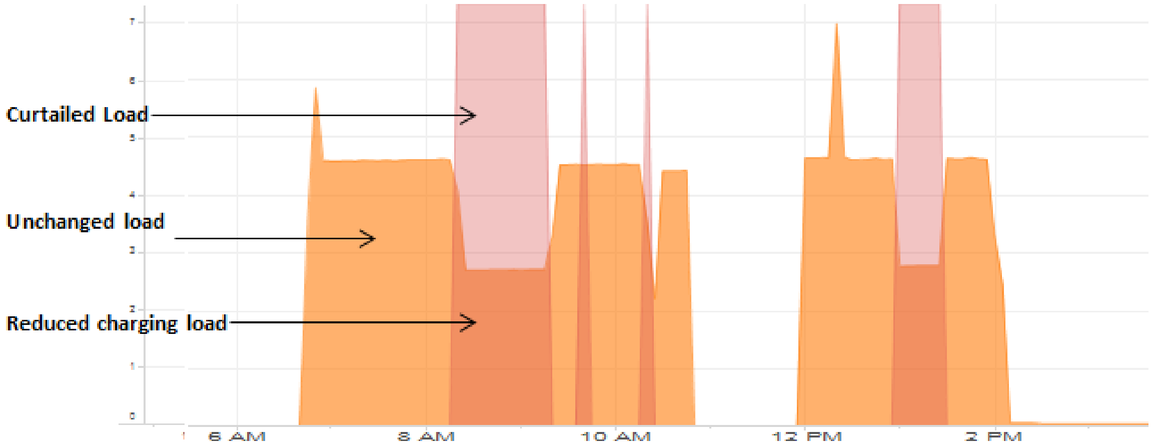
[236] Duty cycling involves allowing the unit to draw power for only a portion of the period, acting as a kind of partial curtailment. Rebound effects are when load increases substantially in the post-event period as a result of prolonged curtailment.

retrofit and new units in the residential market and plans to include both resistance and heat pump water units.

I.1.5 Electric Vehicles

PGE is currently exploring DR opportunities with electric vehicles (EV). PGE has already called DR events on its workplace chargers to demonstrate the capability available through one of the Company's charging vendors. Figure I-2 shows an example of demonstration events called at PGE's Tualatin Contact Center charger.

FIGURE I-2: Example workplace charger DR events



In addition to the continued exploration of workplace chargers, PGE will be researching DR potential as part of its EV employee research pilot. PGE will randomly assign employees with EVs to time-of-use (TOU) rates and/or provide DR-enabled Level Two chargers. The Company will then assess the relative demand impacts of each intervention. Thus far, PGE has called a DR event on one employee DR-enabled charger for demonstration purposes. In conjunction with an Electric Power Research Institute (EPRI) project, PGE will also use the ANSI/CTA-2045 standard for water heaters to test ten residential Smart home EV chargers.

More information on EVs and the work PGE is doing to assess this resource is available in Section 4.2, Plug-in Electric Vehicles.

I.2 Non-Firm Demand Response Programs

I.2.1 Critical Peak Pricing

PGE concluded its Critical Peak Pricing pilot (CPP) for residential customers (Schedule 12) in October 2013. To complete the CPP pilot, PGE submitted a detailed evaluation to Commission Staff in May 2014.

Table I-3 and Table I-4 show the demand impacts in each season for the two year pilot. Note that the summers during the pilot period were particularly mild, leading to muted, and sometimes statistically insignificant, impacts.

TABLE I-3: CPP winter demand impacts

Event Date	Max kW (one hour) Impact One-Day Baseline	Max kW (one hour) Impact Five-Day Baseline	kWh Event Day	kWh One-Day Baseline	kWh Five-Day Baseline	HDD Base 55
			Winter 1			
12/31/2011	0.39	0.25	36.4	37.5	37.6	23.5
1/11/2012	0.2	0.22	35.7	36.8	36.5	19.5
1/18/2012	0.358	0.29	33.4	34.2	32.8	13
1/27/2012	0.2	0.29	34.2	34.2	35.5	20.7
2/2/2012	0.31	0.25	29.4	30.3	30.1	12.5
2/13/2012	0.36	0.32	29.8	31.6	32	14.4
			Winter 2			
1/3/2013	0.26	0.3	37.1	37	37.4	23.5
1/4/2013	0.25	0.21	34.1	34.1	36	18
1/16/2013	0.25	0.28	36.6	36.6	37.5	22.2
2/13/2013	0.17	0.11	27.9	27.9	27.9	7
2/19/2013	0.24	0.21	28.7	28.7	29.1	9.5

TABLE I-4: CPP summer demand impacts

Event Date	Max kW (one hour) Impact One-Day Baseline	Max kW (one hour) Impact Five-Day Baseline	kWh Event Day	kWh One-Day Baseline	kWh Five-Day Baseline	Maximum Daily Temperature (Hillsboro Weather Station)	Minimum Daily Temperature (Hillsboro Weather Station)
Summer 1							
8/6/2012	(*)	(*)	30.8	29.2	27.6	91	65
8/16/2012	(*)	(*)	32.5	29.5	27.2	96	60
8/17/2012	(*)	(*)	31.7	29.2	26.8	98	60
9/7/2012	(*)	(*)	25.7	26.1	25	93	50
9/18/2012	0.22	0.2	22.7	23.3	23.3	89	47
Summer 2							
7/1/2013	(*)	(*)	30.6	29.5	26.5	97	58
8/6/2013	0.23	0.22	27.2	26.9	24.2	91	64
8/21/2013	0.11	0.09	28	28.4	27.6	91	50
9/11/2013	(*)	(*)	29.5	28.8	27.5	91	50

(*) These load impacts cannot be estimated due to baselines that are clearly too low for the event day.

Major aspects of the third-party evaluation include the following:

- The pilot realized measureable load reductions for the comparable event days.
- By far, the main reason to participate was to save money (about 75 percent of respondents). The distant second reason was to save energy (about 10 percent of respondents).
- The main reason for customers to choose to leave the program was that the bill went up after joining the program (38 percent of dropout survey respondents), followed closely by household difficulties to reduce or shift electric usage (29 percent), and did not see advantages for continued participation in the program (22 percent).
- About half of continuing participants said that their bill had changed in the winter, and over 80 percent said that their bill changed in the summer, because of their participation in the pilot.
- About 75 percent of all respondents were satisfied or very satisfied with the pilot enrollment process.
- Most continuing participants and dropouts found the program information easy to understand. Dropouts more often reported not understanding the different electric price categories depending on the time of day and how the program worked in general.

- The majority of continuing participants (close to 90 percent) said they took actions to reduce their energy usage when on-peak rates were in effect. Using dishwashers, clothes washers and/or dryers during off-peak hours was the most common year-round measure, followed by reducing lighting and unplugging unused electronic equipment.
- Survey participants that reported taking action to reduce energy use were asked whether their electricity reductions caused discomfort. Less than 30 percent said that they did.
- Continuing participants that reported being satisfied or very satisfied with the program varied from season to season and averaged about 60 percent. On average, about 75 percent of continuing participants reported that they would recommend the program to others.
- About 89 percent of continuing participants reported to be satisfied or very satisfied with PGE as an electric utility, as did 72 percent of dropouts. These satisfaction rates are much higher than the rates reported for the pilot.
- Continuing participants self-reported that their level of education is higher than that of dropouts (44 percent with four-year college or higher, compared to 34 percent), that their level of income is similar (about 45 percent make $50,000 or less, and about 60 percent make $75,000 or less), and that the rate of home ownership is higher (about 85 percent, compared to 72 percent).

The evaluation found Schedule 12 to be a well-designed rate that can accomplish its goal of increasing load shifting and load reductions in the PGE service territory. Most of the recommendations from the evaluator were regarding program implementation, not the rate design. The PGE CPP and TOU Pilot analysis shows that future, similar programs would benefit from the following:

- Specific and timely feedback regarding their energy costs. One of the results from this study is that the main motivation to participate in programs such as this is to save money. As such, it is very important that PGE provide customers with specific and timely feedback regarding their energy costs. One way to do this is to provide customers with current year / prior year comparisons that show twelve months at a time. PGE could also show customers a comparison of their current expenses to prior year expenses and what the expenses would have been under Schedule 7.
- On-going education and support to help program participants navigate the complexities of their new rate. Pilot participants indicated that customers joined with the expectation to save money, but found some of the program elements confusing, that they did not have enough information about how the program worked, and that they did not receive enough suggestions about how to implement load reductions.
- Future experimental designs may choose to increase access to information to only a part of the pilot or program participants, to assess whether the increased information improves performance under the pilot or not.
- Screening for increased load during event months prior to program solicitation may help to determine the probability that a customer will be successful in this rate.

- In terms of the design of Schedule 12, we suggest that it is not necessary to remove customers that move to another residence within the service territory. In full implementation mode, it is possible that PGE will allow customers to join the program at any time, which means that customers will be able to rejoin when they open an account at their new residence.

I.2.2 Residential Dynamic Pricing Pilot

I.2.2.1 Program Objectives

In order to build on lessons learned from the CPP pilot, PGE is conducting a residential pricing pilot beginning in June 2016 and running through February of 2018. This pilot will target peak load in the summer and winter by using a combination of education about peak energy usage, behavioral DR, Peak Time Rebate (PTR), and/or various versions of TOU. The following section outlines the program details from eligibility to notification and selection. The foremost objective is to test a variety of potential pricing programs in order to identify a pricing program that, when launched at scale, can achieve at least ten percent market penetration, while providing meaningful load-shifting and maintaining or improving satisfaction for participating customers.

I.2.2.2 Customer Experience

There are several aspects to the customer journey through the pilots. The following is an outline of PGE's intent for this pilot, in order to create a positive customer experience for participants, PGE intends for this pilot to focus on the following:

Recruitment

- PGE will recruit customers based upon what the Company knows motivates them and their load segments. This may be a sustainability message, a competitive message, or a savings message.
- PGE will show customers their current bill and the lifestyle changes they could make with the new rates.

Education

- PGE will send customers receive ongoing (monthly) information about how well they are doing on their new rate and on changes that can positively affect their bill to take greatest advantage of the rates.
- PGE will provide a complete library of solutions tailored based upon the customer segment.

Energy Information

- PGE will connect customers with their energy usage information online to allow them to see the impact of the timing of usage on their bill.
- PGE will provide PTR customers with a web tool demonstrating their performance on a regular event and how they can improve.

PGE will use the following criteria to select the pool of eligible participants:

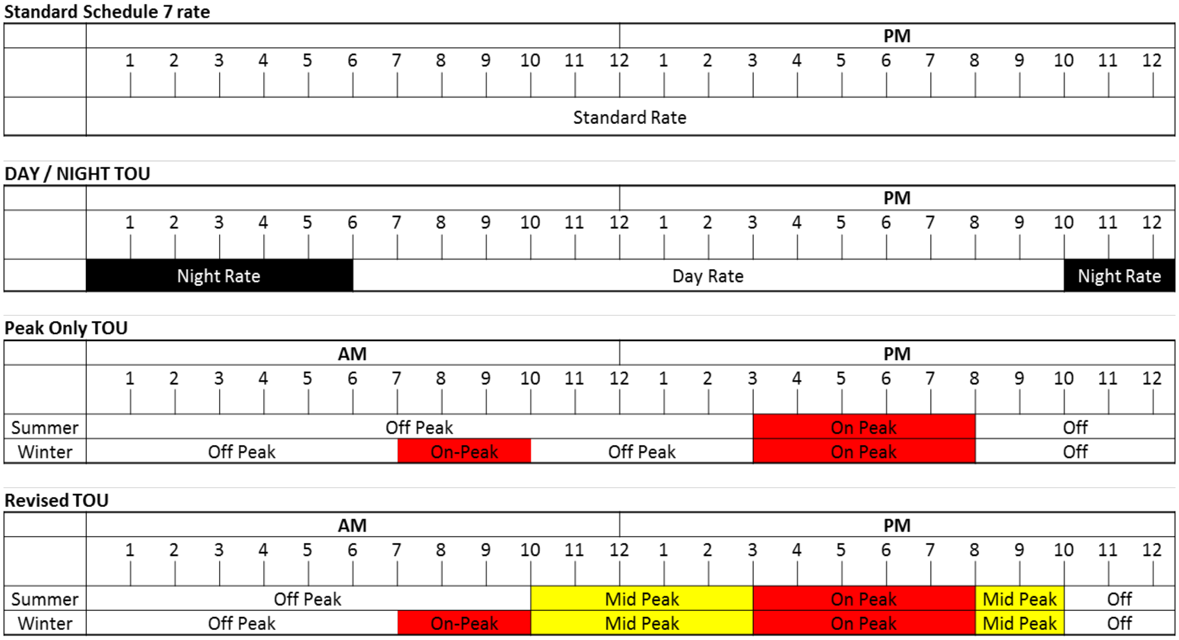
- Residential customer not currently enrolled in time of use;
- Greater than 100 kWh consumption per month;
- 12 months of previous billing data;
- Not currently on a time-payment agreement; and
- In a home capable of delivering 15-minute watt hour resolution data.

PGE will consider all customers meeting the above criteria eligible to participate, irrespective of load segment. All customers are capable of participating, as there are no technology requirements.

PGE carefully considered the needs of low-income customers in designing this pilot. The Company is interested in testing PTR because of the high satisfaction and energy savings noted in other utility studies among low-income and other customer segments. In addition, load shape segmentation reveals that low-income customers are important contributors to PGE's winter peaks, making this group an important part of pilot success.

The factors PGE evaluated to develop the pilot were the peak load duration, customer effects, retention, and program persistence. Figure I-3 provides an outline of our proposed TOU periods to be tested. PGE designed these schedules to capture weekday peak hours during each season, while maintaining consistency between seasons.

FIGURE I-3: TOU rate schedule



Standard Schedule 7 rate

													PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
	Standard Rate																							

DAY / NIGHT TOU

													PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
	Night Rate						Day Rate																Night Rate	

Peak Only TOU

	AM												PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
Summer	Off Peak															On Peak					Off			
Winter	Off Peak							On-Peak			Off Peak					On Peak					Off			

Revised TOU

	AM												PM											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
Summer	Off Peak										Mid Peak					On Peak					Mid Peak		Off	
Winter	Off Peak							On-Peak			Mid Peak					On Peak					Mid Peak		Off	

PGE designed TOU pricing for the pilots to be revenue neutral on an annual basis, assuming no change in energy usage behavior by participants. Differentials in peak periods rely on the energy prices used in MONET, PGE's net variable power cost modeling tool.

PGE takes the day with the highest projected summer peak. For that day, PGE averages the hourly prices for each peak period to establish differentials between the peak periods. PGE then applies the differential to the average kWh in a month for each peak period, so that it yields the same bill as on PGE's standard residential rate schedule. The goal of the pilot's rates is to reflect PGE's variable power cost in the different periods and reward customers for lowering costs.

Finding the right rate/program design is critical to cost-effectively achieve demand savings. The pilot will test ten opt-in pricing treatments, one opt-out behavior treatment (BDR), and one opt-out pricing treatment (PTR 2), for a total of 12 treatments. The opt-in pricing treatments correspond to the three TOU rates, the three PTR rates, TOU2 x BDR, TOU1 x PTR2, TOU2 x PTR2, and TOU3 x PTR2.

TABLE I-5: Summary of proposed research design

Summary of Proposed Research Design					
	Customer Rate				
	Flat Rate	TOU 1	TOU 2	TOU 3	Total
Group A: Opt-in Pricing Test					
Offer TOU only					
TOU only		390	875	390	1,655
TOU x BDR			875		875
Control		390	390	390	1,170
Total		780	2,140	780	3,700
Offer TOU x PTR					
TOU x PTR2 (O-I)		220	220	220	660
Control		220	220	220	660
Total		440	440	440	1,320
Offer PTR 1 only					
PTR (O-I) only	220				220
Control	220				220
Total	440				440
Offer PTR 2 only					
PTR (O-I) only	220				220
Control	220				220
Total	440				440
Offer PTR 3 only					
PTR (O-I) only	220				220
Control	220				220
Total	440				440
Total Opt-in Pricing Pilot	1,320	1,220	2,580	1,220	6,340
Group B: Behavioral Demand Response Test					
Treatment	13,180				13,180
Control	13,180				13,180
Total	26,360				26,360
Group C: Opt-out PTR2 Test					
Treatment	430				430
Control	430				430
Total	860				860
Pilot Totals					
Pilot Customers	28,540	1,220	2,580	1,220	33,560
Pilot Customers in a Pricing Treatment or Control Group (Group A + Group C)	2,180	1,220	2,580	1,220	7,200

I.2.2.3 Residential Dynamic Pricing: Demand Response Events

PGE plans for program events to be up to five hours. PGE will issue a notification of a PTR event—as well as follow-up reminders—to participating customers by 4:00 p.m. the day prior to the PTR event, as well as follow-up reminders. The Company will use the following methodology to call events:

Determine Need

After collecting the above-described data and determining compliance with the general program criteria, the program manager discusses grid needs, current conditions, and load and pricing trends with key PGE personnel.

Event Called

The program manager logs onto a secure web site (FERC Level Security) and inputs the timing and duration of the event.

Notice Dispatched to Participants

The day before an event, the vendor will notify customers of the upcoming event via the customer's preferred communication channel (e.g., email, SMS, IVR). Closer to the event, the vendor will also send reminders/alerts using the format selected by the customer. The vendor's notification will inform the customer of the time and duration of the event, as well as remind them of the rebate level.

Opt-Out

If the customer decides to opt-out of an event, they do not need to notify PGE. The Company simply will not pay the customer if no demand reduction is on the customer's bill.

Actual Event

During an actual event, customers are free to make changes in their electricity usage. The most common and effective changes include, adjusting HVAC settings or not running major appliances such as washers, dryers, or pool pumps.

Post Event

The day after the event, the customer will receive information on their performance via text, email, website, mobile app notification, or telephone depending on their communication preference selection.

Billing and Payment

The customer's monthly billing continues to be on the current PGE system. For any PTR due to the customer, PGE will send the customer a single check at the end of the season. The customer will be able to see in the portal how much they can expect to receive for each of their events.

I.2.2.4 Residential Dynamic Pricing: Pilot Evaluation

PGE contracted with a third-party evaluator for the pricing pilot. The evaluator will provide ongoing evaluation, measurement, and verification throughout the program. PGE began working with the evaluator prior to the start of customer recruitment to allow them an opportunity to consult on the implementation of the experimental design, conduct all necessary randomization, and ensure that

PGE is collecting the necessary data. The evaluator will also provide full process and impact evaluation reports at the end of program year one and at the completion of the pilot.

For the impact evaluation, PGE will estimate demand impacts econometrically using historical data from both the treatment and control groups. This analysis will estimate both event period impacts as well as impacts in hours just before and after events to determine any possible rebound effects. PGE will also track opt-out rates for each event.

For the purposes of determining the PTR, PGE will measure customer performance as the difference in energy consumed over the peak period and their personalized baseline. PGE will use its AMI system to calculate the load profile for each participating customer. PGE plans to use customer-level regression analysis to estimate baselines for participants in the PTR and behavioral DR portions of the pricing pilot. The Company will use baselines to calculate kWh savings over event periods, which PGE will report to customers the day after an event. The Company will measure customer satisfaction through surveys at the end of each season to ensure that customers are happy with their experience. PGE will correct any identified problems on an ongoing basis.

It is PGE's expectation that there will be checkpoints six months after each summer season, similar to the Flex Price^{SM} and Energy Partner^{SM} Pilots.

I.2.3 Time-of-Day Pricing

Time-of-Day (ToD) pricing currently applies to PGE's Schedule 83, 85, and 89 customers. This means that ToD pricing is available for all nonresidential customers with monthly demand greater than 30 kW.

APPENDIX J. ICF International Assessment of the Technical and Economic Potential for CHP in Oregon

Assessment of the Technical and Economic Potential for CHP in Oregon

Final Report

July 2014

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Introduction

Combined Heat and Power (CHP), also known as cogeneration, produces electricity and useful thermal energy in an integrated system. CHP systems can range in size from hundreds of megawatts - such as those being operated at refineries and in enhanced oil recovery fields down to a few kilowatts that are used in small commercial and even residential applications. Combining electricity and thermal energy generation into a single process can save up to 35 percent of the energy required to perform these tasks separately. This report presents the results of a CHP market assessment undertaken for the Oregon Department of Energy to identify the technical and economic potential for CHP market penetration given the current market and regulatory atmosphere for CHP in Oregon. Recommended CHP priority target market criteria with target market recommendations and rationale are also included. Oregon has 41 retail electric utility providers with a wide range of industrial and commercial electric rates and electric rate structures. Per the U.S. Department of Energy's Energy Information Administration's 2011 Electric Sales and Revenue Report, three utilities have over 9,000 industrial and commercial customers (Portland General Electric, Pacific Power, and Eugene Water and Electric) in applications suitable for CHP with electric demand 50 kW or greater. Additional CHP analysis was developed for these three utilities.

Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% load factor and above) and low load factor (51% load factor) applications, resulting in four distinct market segments that are analyzed.

- High load factor traditional CHP (heating only)
- Low load factor traditional CHP (heating only)
- High load factor cooling CHP (heating and cooling)
- Low load factor cooling CHP (heating and cooling)

Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often need more thermal energy than electrical energy to produce their products, leading them to have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially expand benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months, and a portion of the cooling load during the summer months. Two sub-categories were considered:

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of heating thermal load, but with the addition of cooling, can support CHP with low load hours. These applications include schools, big box retail stores, museums, movie theaters, supermarkets, and restaurants.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP. Of note is the Oregon Thermal Baseline, developed by the Oregon Department of Energy, which was used to corroborate data from other databases.
- Estimation of CHP potential by megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration. It is noted that biomass feedstocks are often available in Oregon where natural gas is not available, however this analysis only covers natural gas fueled CHP and waste heat to power (WHP) systems.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Oregon, there are 65 operating CHP plants totaling 2,838 MW of capacity[1]. Of this existing CHP capacity, 57% of the number of sites and 86% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential. A summary of the existing CHP capacity by industry is shown in Table 1.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS),* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the ICF CHP Technical Potential database was utilized to identify potential CHP sites by SIC code or application, and location. The ICF CHP Technical Potential Database is based on a variety of sources for facility level information including: the Oregon Thermal Baseline by the Oregon Department of Energy, the Oregon Boiler database, EPA Greenhouse Gas Reporting Rule database, the Dun and Bradstreet Hoovers database, the Manufacturers News database, Major Industrial Plant Database (MIPD), and industry specific data sources (i.e. Lockwood Post, Iron & Steel Directory, Oil & Gas Journal, etc.). Commercial application-specific information was used from the American Hospital Association, the Database of Accredited Post-Secondary Institutions, the Dept. of Justice (prisons), and the Dept. of Education, etc.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the thermal demand for the facility unless the thermal loads (heating and cooling) would exceed the average electric demand. Table 3 and Table 4 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load, resulting in a total of four market segments. In traditional CHP, the thermal energy is recovered and used for heating,

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[1] CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory. 2014.

process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. Figure 1 and Figure 2 offer another depiction of CHP technical potential in Oregon, showing total CHP sites and MW potential by major utility.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2030 by target market sectors in Oregon. The growth factors used in the analysis for growth between the present and 2030 by individual sector are shown in Table 5. These growth projections were taken from the EIA 2014 Annual Energy Outlook and were used in this analysis as an estimate of the growth in new facilities or expansion of existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table 6 and Table 7.

Table 1 – Existing CHP in Oregon

SIC	Application	# Sites	Capacity (MW)
1	Agriculture	1	0.04
2	Livestock	9	10.7
20	Food Processing	4	1,368.0
24	Lumber and Wood	15	135.8
26	Paper	7	931.0
33	Primary Metals	1	14.0
4939	Utilities	3	316.4
4952	Wastewater Treatment	11	8.2
4953	Solid Waste	3	20.4
5812	Restaurants	1	0.01
6512	Commercial Buildings	1	0.03
8220	Colleges/Universities	4	24.3
9100	Government	1	0.01
9900	Other	4	9.1
Total		65	2,837.8

Table 2 – CHP Technical Potential by Electric Utility Territory (MW Capacity)

Electric Utility	50-500 kW	500-1 MW	1-5 MW	5-20 MW	>20 MW	Total
Portland General Electric	163	105	182	76	87	614
Pacific Power & Light	97	76	99	102	98	471
Eugene Water & Electric Board	21	12	51	0	0	84
Other Electric Companies	57	51	94	16	71	289
Total	338	244	425	195	255	1,457

Table 3 – Oregon Technical Market Potential for CHP in Existing Facilities – Industrial Sector

		50-500 kW		500-1,000 kW		1-5 MW		5-20 MW		>20 MW		Total	
SIC	Application	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)
20	Food	170	29.3	29	20.7	23	45.8	2	15.6	0	0	224	111.3
22	Textiles	4	1	0	0	2	4.7	0	0	0	0	6	5.7
24	Lumber and Wood	233	47.6	54	36.6	44	93.2	10	75.4	0	0	341	252.7
25	Furniture	1	0.1	0	0	0	0	0	0	0	0	1	0.1
26	Paper	29	6	7	5.1	11	29.4	2	18.8	5	221.8	54	281.2
27	Printing	11	1.3	1	0.7	0	0	0	0	0	0	12	2
28	Chemicals	69	12.1	12	7.9	17	34.7	3	25.3	1	33.3	102	113.4
29	Petroleum Refining	0	0	3	2.1	3	6.3	0	0	0	0	6	8.4
30	Rubber/Misc Plastics	55	8.7	2	1.4	1	2.3	0	0	0	0	58	12.4
32	Stone/Clay/Glass	0	0	0	0	1	2.8	0	0	0	0	1	2.8
33	Primary Metals	20	5.1	4	3	7	15.5	1	6.9	0	0	32	30.6
34	Fabricated Metals	9	1.6	0	0	0	0	0	0	0	0	9	1.6
35	Machinery/Computer Equip	5	0.5	0	0	0	0	0	0	0	0	5	0.5
37	Transportation Equip.	24	3.4	0	0	5	6.1	0	0	0	0	29	9.5
38	Instruments	3	0.6	0	0	1	4.1	0	0	0	0	4	4.8
39	Misc. Manufacturing	3	0.2	0	0	0	0	0	0	0	0	3	0.2
	Total	636	117.6	112	77.6	115	245.1	18	142	6	255.1	887	837.5

Table 4– Oregon Technical Market Potential for CHP in Existing Facilities – Commercial Sector

		50-500 kW		500-1,000 kW		1-5 MW		5-20 MW		>20 MW		Total	
SIC	Application	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)	# Sites	Capacity (MW)
43	Post Offices	3	0.3	0	0	0	0	0	0	0	0	3	0.3
52	Retail	190	20.8	4	2.5	0	0	0	0	0	0	194	23.3
4222	Refrigerated Warehouses	9	0.8	1	0.5	1	1.6	0	0	0	0	11	2.9
4581	Airports	3	0.9	0	0	0	0	1	6.3	0	0	4	7.2
4952	Water Treatment	16	1.9	1	0.6	0	0	0	0	0	0	17	2.6
5411	Food Stores	169	20.2	0	0	2	5.2	0	0	0	0	171	25.4
5812	Restaurants	242	22.6	0	0	0	0	0	0	0	0	242	22.6
6512	Commercial Buildings	726	36.3	223	89.2	56	33.6	0	0	0	0	1,005	159.1
6513	Multifamily Buildings	149	11.2	54	27	8	8.4	0	0	0	0	211	46.6
7011	Hotels	189	24.8	8	5.5	5	7.6	1	5	0	0	203	42.9
7211	Laundries	23	3.3	1	0.8	0	0	0	0	0	0	24	4
7374	Data Centers	31	5.7	2	1.3	1	1.4	0	0	0	0	34	8.4
7542	Car Washes	11	0.8	0	0	0	0	0	0	0	0	11	0.8
7832	Movie Theaters	1	0.1	1	0.9	0	0	0	0	0	0	2	1
7991	Health Clubs	47	5.2	1	0.6	0	0	0	0	0	0	48	5.8
7997	Golf/Country Clubs	44	5.2	0	0	2	2.7	0	0	0	0	46	7.9
8051	Nursing Homes	121	11.7	0	0	0	0	0	0	0	0	121	11.7
8062	Hospitals	37	9.1	12	8.1	16	38	0	0	0	0	65	55.3
8211	Schools	4	0.2	0	0	0	0	0	0	0	0	4	0.2
8221	College/Univ.	33	6.5	9	6.3	17	41.2	4	35.4	0	0	63	89.4
8412	Museums	12	1.5	0	0	0	0	0	0	0	0	12	1.5
9100	Government Buildings	204	29.2	27	19.5	9	15.1	0	0	0	0	240	63.8
9923	Prisons	4	1.5	3	2.1	7	21	1	5.9	0	0	15	30.5
9711	Military	3	0.4	1	1	1	4.7	0	0	0	0	5	6.1
	Total	2,271	220.2	348	165.8	125	180.5	7	52.7	0	0	2,751	619.2

Figure 1– Oregon CHP Technical Potential (MW) by Utility

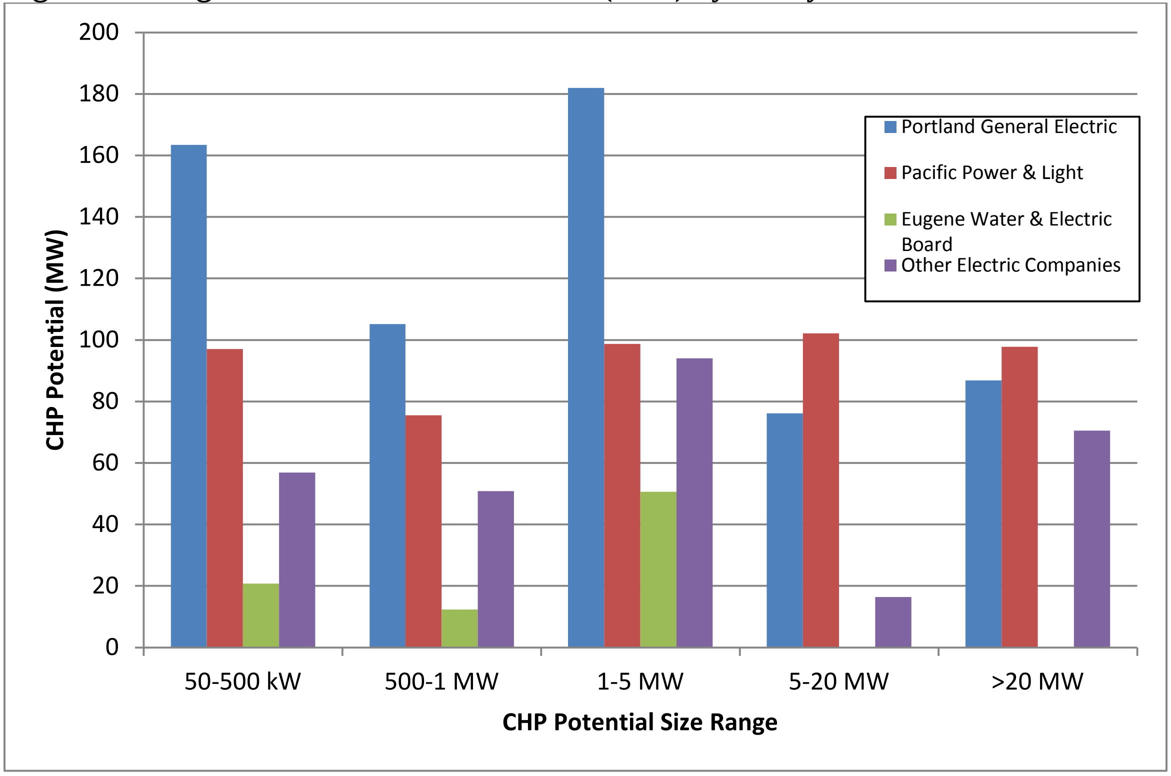

Figure 2– Oregon CHP Technical Potential (Sites) by Utility

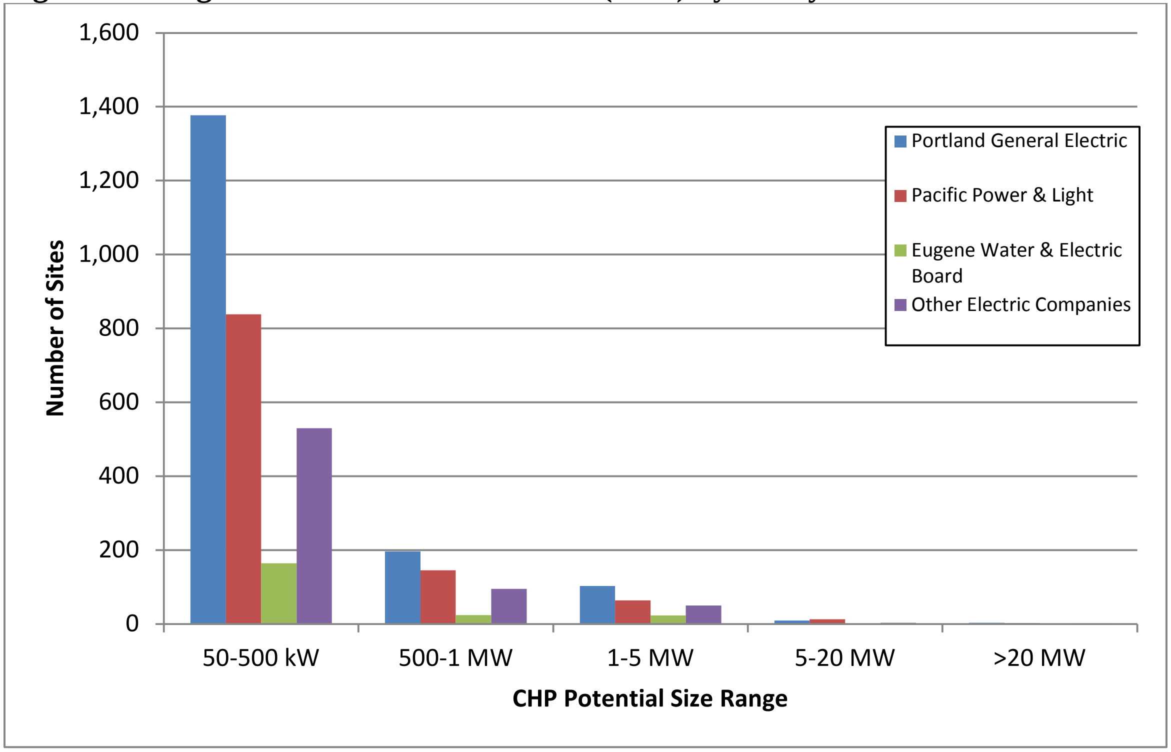

Table 5–Oregon Sector Growth Projections Through 2030

SIC	Application	Yearly 2014-2030 Growth Rate	Cumulative 2014-2030 Growth Rate
20	Food & Beverage	1.8%	32.4%
22	Textiles	0.0%	0.0%
24	Lumber and Wood	0.5%	9.0%
25	Furniture	1.1%	19.4%
26	Paper	1.9%	34.8%
27	Printing/Publishing	0.6%	10.4%
28	Chemicals	2.4%	46.6%
29	Petroleum Refining	0.0%	0.0%
30	Rubber/Misc Plastics	1.5%	26.3%
32	Stone/Clay/Glass	1.3%	23.2%
33	Primary Metals	0.4%	6.8%
34	Fabricated Metals	1.3%	22.9%
35	Machinery/Computer Equip	2.5%	48.0%
37	Transportation Equip.	2.3%	43.1%
38	Instruments	2.6%	50.4%
39	Misc Manufacturing	4.8%	111.9%
49	Gas Processing	1.3%	22.5%
4952	Water Treatment/Sanitary	0.7%	11.2%
9923	Prisons	1.5%	27.2%
9711	Military	1.5%	27.2%
7211	Laundries	1.5%	27.2%
7542	Carwashes	1.5%	27.2%
7991	Health Clubs	1.5%	27.2%
7997	Golf/Country Clubs	1.5%	27.2%
4222	Refrigerated Warehouses	1.5%	27.2%
6513	Multi-Family Buildings	1.5%	26.9%
7011	Hotels	1.2%	21.5%
7374	Data Centers	4.0%	87.3%
8051	Nursing Homes	1.3%	22.1%
8062	Hospitals	1.3%	22.1%
8221	Colleges/Universities	0.4%	7.1%
43	Post Offices	1.5%	27.2%
52	Big Box Retail	1.0%	16.4%
4581	Airports	1.5%	27.2%
5411	Food Sales	1.0%	17.3%
5812	Restaurants	1.1%	18.6%
6512	Commercial Buildings	1.2%	20.3%
7832	Movie Theaters	0.5%	8.0%
8211	Schools	0.4%	7.1%
8412	Museums	0.5%	8.0%
9100	Government Facilities	1.2%	20.3%

Table 6– Industrial CHP Market Segments, Existing Facilities and Expected Growth 2015-2030

			50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total
SIC	Application	Total Growth Rate (2015 to 2030)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)
20	Food	32%	38.8	27.4	60.6	20.6	0	147.4
22	Textiles	0%	1	0	4.7	0	0	5.7
24	Lumber and Wood	9%	51.9	39.9	101.6	82.1	0	275.5
25	Furniture	19%	0.1	0	0	0	0	0.1
26	Paper	35%	8.1	6.9	39.7	25.4	298.9	379
27	Printing	10%	1.4	0.8	0	0	0	2.2
28	Chemicals	47%	17.7	11.6	50.9	37.2	48.9	166.3
29	Petroleum Refining	0%	0	2.1	6.3	0	0	8.4
30	Rubber/Misc. Plastics	26%	11	1.8	2.9	0	0	15.7
32	Stone/Clay/Glass	23%	0	0	3.5	0	0	3.5
33	Primary Metals	7%	5.5	3.2	16.6	7.4	0	32.7
34	Fabricated Metals	23%	2	0	0	0	0	2
35	Machinery/Computer Equip	48%	0.8	0	0	0	0	0.8
37	Transportation Equip.	43%	4.9	0	8.7	0	0	13.6
38	Instruments	50%	1	0	6.2	0	0	7.2
39	Misc. Manufacturing	112%	0.5	0	0	0	0	0.5
	Total		144.5	93.7	301.8	172.7	347.8	1,060.5

Table 7 - Commercial CHP Market Segments, Existing Facilities and Expected Growth 2015-2030

			50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total
SIC	Application	Total Growth Rate (2015 to 2030)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)	Capacity (MW)
43	Post Offices	27%	0.4	0	0	0	0	0.4
52	Retail	16%	24.3	2.9	0	0	0	27.2
4222	Refrigerated Warehouses	27%	1	0.7	2.1	0	0	3.8
4581	Airports	27%	1.1	0	0	8.1	0	9.2
4952	Water Treatment	11%	2.2	0.7	0	0	0	2.9
5411	Food Stores	17%	23.7	0	6.1	0	0	29.8
5812	Restaurants	19%	26.7	0	0	0	0	26.7
6512	Commercial Buildings	20%	43.7	107.3	40.4	0	0	191.4
6513	Multifamily Buildings	27%	14.2	34.3	10.6	0	0	59.1
7011	Hotels	22%	30.1	6.7	9.2	6.1	0	52.1
7211	Laundries	27%	4.2	1	0	0	0	5.2
7374	Data Centers	87%	10.7	2.4	2.6	0	0	15.7
7542	Car Washes	27%	1	0	0	0	0	1
7832	Movie Theaters	8%	0.1	0.9	0	0	0	1
7991	Health Clubs	27%	6.6	0.7	0	0	0	7.3
7997	Golf/Country Clubs	27%	6.7	0	3.4	0	0	10.1
8051	Nursing Homes	22%	14.3	0	0	0	0	14.3
8062	Hospitals	22%	11.1	9.9	46.4	0	0	67.4
8211	Schools	7%	0.3	0	0	0	0	0.3
8221	College/Univ.	7%	6.9	6.8	44.1	37.9	0	95.7
8412	Museums	8%	1.6	0	0	0	0	1.6
9100	Government Buildings	20%	35.1	23.5	18.2	0	0	76.8
9923	Prisons	27%	1.9	2.7	26.7	7.5	0	38.8
9711	Military	27%	0.6	1.2	6	0	0	7.8
	Total		268.3	201.5	215.9	59.6	0	745.3

Waste Heat to Power CHP Technical Potential

In addition to exploring the technical potential of traditional topping cycle CHP in Oregon, this assessment also evaluated the potential for waste heat to power (WHP) in the state. Waste heat to power (WHP) is the process of capturing heat discarded by an existing process to generate power.[2] The following two tables represent current waste heat to power technical potential in Oregon by utility and by application.

Table 8– Waste Heat to Power Potential by Major Utility

Utility Territory	# of Sites	WHP Potential (MW)
Portland General Electric	2	3.2
Pacific Power & Light	10	24.1
Other Electric Company	10	15.2
Total	22	42.4

Table 9– Waste Heat to Power Potential by Application

NAICS Code	Application	# of Sites	WHP Potential (MW)
327310	Cement Manufacturing	1	4.1
486210	Pipeline Transportation of Natural Gas	12	12.1
327213	Glass Container Manufacturing	1	2.9
327420	Gypsum Product Manufacturing	1	3.4
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1	18.3
562212	Solid Waste Landfill	6	1.6
	Total	22	42.4

Economic Potential for CHP

The economic potential for CHP is quantified using payback for CHP systems. Payback is defined as the amount of time (i.e. number of years) before a system can recoup its initial investment. For each site included in the technical potential analysis, an economic payback is calculated based on the appropriate CHP system cost and performance characteristics and energy rates for that system size and application. This section lays out the economic conditions in Oregon that were used to calculate the payback for each technical potential application and size range.

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[2] U.S. EPA, Waste Heat to Power Systems fact sheet.

Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP.

Electric Price Estimation

While state-average spark spreads may mask the differences in specific utility rates on project economics, ICF researched the applicable rates (i.e. full service and partial service/standby rates) for the three largest utilities in Oregon to develop an avoided cost estimate for each utility. The avoided cost is an important concept for evaluating the treatment of onsite generation by partial requirement tariff structures. One of the key economic values of onsite generation is the displacement of purchased electricity and the avoidance of those costs. Ideally, the reduction in electricity price should be commensurate with the reduction in purchased electricity. In other words, if the onsite system reduces electricity consumption by 80 percent, the cost of electricity purchases would also be reduced by 80 percent in an ideal scenario. However, only a portion of the full retail rate is avoided by on-site generation due to fixed customer charges, demand charges, and standby rate structures. The economics of CHP are negatively impacted if partial requirements rates are structured such that only a small portion of the electricity price can be avoided.

The utilities analyzed include Pacific Power, Portland General Electric, and Eugene Water & Electric Board. Facilities in other municipal or coop utility districts were assumed to have rates similar to the Eugene Water & Electric Board. The rates for CHP customers for each utility are shown in Table 10, Table 11, and Table 12.

Table 10 – Pacific Power CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	> 20,000
High Load Factor (hours)	8760	8760	8760	8760	8760
CHP Availability (%)	95%	95%	95%	95%	95%
Voltage Class	Secondary	Secondary	Primary	Transmission	Transmission
Tariff Class	30	30	47	47	47
Avoided Rate, $/kWh	0.0817	0.0782	0.0639	0.0629	0.0626
Avoided Rate as % of Retail Rate	81.1%	86.5%	91.9%	90.3%	90.7%

Table 11 – Portland General Electric CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000	5,000-20,000	> 20,000
High Load Factor (hours)	8760	8760	8760	8760	8760
CHP Availability (%)	95%	95%	95%	95%	95%
Voltage Class	Secondary	Secondary	Primary	Sub-T	Sub-T
Tariff Class	85	85	75	75	75
Avoided Rate, $/kWh	0.0784	0.0779	0.0695	0.0676	0.0676
Avoided Rate as % of Retail Rate	93.7%	96.0%	88.9%	93.3%	94.0%

Table 12 – Eugene Water & Electric Board CHP Customer Electric Rate Summary

System Size Range (kW)	50-500	500-1,000	1,000-5,000
High Load Factor (hours)	8760	8760	8760
CHP Availability (%)	95%	95%	95%
Tariff Class	G-2	G-3	G-3
Voltage Class	Secondary	Secondary	Primary
Avoided Rate, $/kWh	0.0678	0.0571	0.0560
Avoided Rate as % of Retail Rate	95.6%	90.1%	95.7%

To estimate the escalation of electric prices over the 2014-2030 timeframe, forecasts form EIA's 2014 Annual Energy Outlook for the WECC[3]/Northwest region were used to escalate Porland General Electric and Eugene Water & Electric Board rates by 0.5 percent per year. Pacific Power's growth rate was estimated using historical prices from EIA. The real compound annual growth rate for Pacific Power rates between 2007 and 2011 is about 6%/yr, and the rate assumed in the model going forward is halved at 3%/yr. The annual price forecasts provided were converted to 5 year averages for use in the market model.

Natural Gas Price Estimation

The natural gas prices used in the analysis are shown below in Table 13. These prices reflect the 2013 annual Oregon state-average rates from EIA[4]. The specific rate for each size range is as follows:

- 50 – 500 kW: OR Commercial average
- 500 – 1 MW: OR Industrial average + 20 percent[5]
- 1 – 5 MW: OR Industrial average
- 5 – 20 MW: OR Industrial average
- >20 MW : OR Citygate average

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[3] Western Electric Coordinating Council

[4] Energy Information Administration. Natural Gas Prices. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SOR_a.htm

[5] 20 percent adder based on past natural gas tariff analysis for these size categories

The escalation rate for natural gas prices over the 2014-2030 timeframe was 1.4 percent per year and was taken from the EIA Annual Energy Outlook 2014 reference case, for the WECC/Northwest region.

Table 13 – Natural Gas Price by CHP System Size Bin ($/MMBtu)

Year	50-500 kW	500-1 MW	1-5 MW	5-20 MW	> 20 MW
2014	$8.67	$6.63	$5.53	$5.53	$4.69
2020	$9.43	$7.22	$6.02	$6.02	$5.11
2025	$10.12	$7.75	$6.45	$6.45	$5.48
2030	$10.86	$8.31	$6.93	$6.93	$5.88

CHP Technology Cost and Performance

CHP systems use fuel to generate electricity and useful heat for the customer. There are many different technologies and products that are capable of generating electricity and useful heat. While these technologies differ in terms of system configuration and operation, the economic value of CHP depends on key factors common to all CHP technologies:

- Installed capital cost of the system, on a unit basis expressed in $/kWh. A subset of capital costs are emissions treatment equipment costs that are required to bring some CHP systems into compliance with California (or other regional non-attainment areas) emissions requirements.
- Fuel required to generate electricity, commonly expressed as the heat rate in Btu/kWh. All heat rates in this report are expressed in terms of the high heating value (HHV) of the fuel. This is the same basis on which natural gas is measured and priced for sale. Vendors typically express engine heat rates in terms of lower heating value (LHV) which does not include the heat of vaporization of the moisture content of the exhaust. Consequently, vendor efficiency and heat rate quotes for natural gas fueled equipment are about 10-11 percent higher than HHV estimates, which reflects the difference in the HHV and LHV heat contents for a given volume of natural gas.
- Useful thermal energy produced per unit of electricity output (again expressed as Btu/kWh).
- Non-fuel operating and maintenance costs, expressed on unit basis in $/kWh. These annual costs include amortization of overhaul costs that can be required after a number of years of operation.
- Economic life of the equipment.

The cost and performance parameters for the representative CHP systems used in this analysis are based on updated versions that ICF is currently working on of CHP technology characterizations prepared for NYSERDA and the EPA CHP Partnership.[6] Data is presented on the representative CHP system characteristics that were used for each size range category in Table 14. The top portion of the table shows the CHP system characteristics for traditional heat utilization (hot water or steam) while the bottom portion of the table shows the additional cost and performance parameters associated with a

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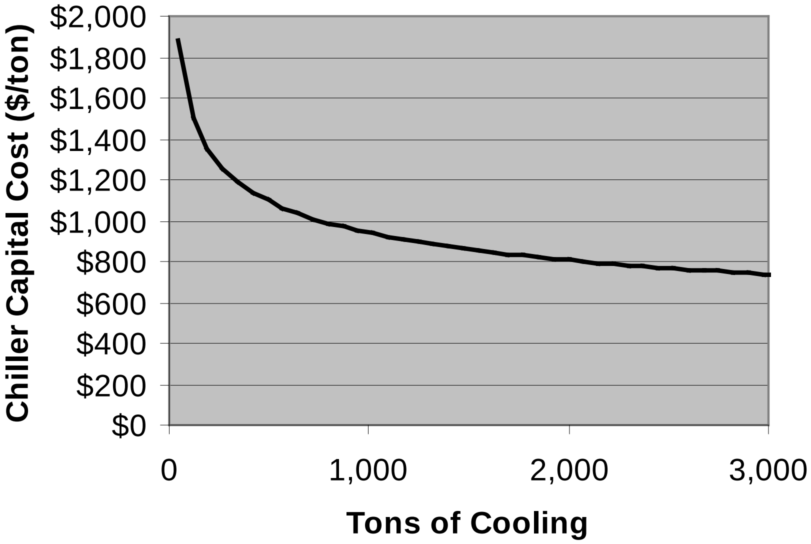
[6] EPA CHP Partnership Program, Technology Characterizations, 2008. http://www.epa.gov/chp/technologies.html.

CHP system used for cooling. In the cooling markets, the additional cost to add chiller capacity to the CHP system is shown in Figure 3. These costs depend on the sizing of the absorption chiller, which in turn depends on the amount of usable waste heat that the CHP system produces.

Table 14 – CHP Cost and Performance Assumptions

Market Size Bin	50-1,000 kW	1-5 MW	5-20 MW	>20 MW
Technology	500 kW RE	3000 kW RE	10 MW GT	40 MW GT
Capacity, kW	500	3,000	12,500	40,000
Capital Cost $/kW	$2,217	$1,604	$1,802	$1,144
After-Treatment Cost, $/kW	$552	$313	$174	$104
Total Capital Cost, $/kW	$2,769	$1,917	$1,976	$1,248
Heat Rate, Btu/kWh	11,293	8,454	12,482	9,488
Thermal Output, Btu/kWh	5,546	3,208	5,262	3,118
Electric Efficiency, %	30.2%	40.4%	27.3%	36.0%
CHP Overall Efficiency	79.3%	78.3%	69.5%	68.8%
O&M Costs, $/kWh	$0.0215	$0.0150	$0.0120	$0.0092
Economic Life, years	15	15	20	20
Avoided Boiler Efficiency	80%	80%	80%	80%
Avoided AC Efficiency, kW/ton	1.00	0.68	0.68	0.68
Cooling Hours	2,000	2,000	2,000	2,000
Absorption Cooling Efficiency, Btu/ton	17,143	17,143	10,000	10,000
Tons of cooling	166	561	6,578	12,473
kW AC/kW Generated	0.32	0.13	0.36	0.21
Capital Cost, $/ton	$1,845	$1,410	$950	$950
Capital Cost Adder, $/kWe	$597	$264	$500	$296

Figure 3 - Absorption Chiller Capital Costs



Waste Heat to Power Cost/Performance

ICF used in-house data, published literature, and held discussions with industry stakeholders to develop cost estimates for steam rankine cycle (SRC) and organic rankine cycle (ORC) systems. SRC and ORC technologies account for nearly all WHP systems currently installed, and are expected to be the dominate technologies that will be installed for the next several years. Other waste heat to power technologies, including emerging technologies, have not yet matured and are therefore not included in this cost analysis. The following assumptions were used to develop the economic analysis of WHP sites:

- Table 15 shows the breakdown of technologies used by NAICS codes. Waste heat stream temperatures have a significant influence on the type of technology a site will choose. In practice, SRC and ORC technologies overlap in each sector. For the purposes of this analysis, however, SRC and ORC technologies are assumed to be divided along typical NAICS codes for that technology.
- Table 16 shows the costs used in the payback calculations of each waste heat to power technology and size range. Costs were differentiated by size to infer economies of scale, meaning that higher capital and O&M costs were assigned to smaller capacity equipment, and vice versa.

Table 15 - Technology Assignment by NAICS Code

NAICS	NAICS Description	WHP Technology
211	Oil and Gas Extraction	ORC
212	Mining except Oil and Gas	ORC
311	Food	SRC
312	Beverage and Tobacco	SRC
321	Wood	SRC
322	Paper	SRC
323	Printing	SRC
324	Petroleum Refining	SRC
325	Chemical	SRC
327	Non-Metallic Minerals	SRC
331	Primary Metals	SRC
333	Machinery	SRC
336	Transportation Equipment	SRC
486	Pipeline Transportation	ORC
562	Waste Management	ORC
611	Colleges	SRC

Table 16 - Waste Heat to Power Cost Assumptions

Technology	Cost Characteristic	Electric Capacity for WHP Technology				
		50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW
Steam Rankine Cycle	Installed Capital Cost, $/kW	$3,000	$2,500	$1,800	$1,500	$1,200
	O&M Costs, $/kWh	$0.013	$0.009	$0.008	$0.006	$0.005
Organic Rankine Cycle	Installed Capital Cost, $/kW	$4,500	$4,000	$3,000	$2,500	$2,100
	O&M Costs, $/kWh	$0.020	$0.015	$0.013	$0.012	$0.010

Economic Potential Results

CHP project economics are site-specific. Utility-specific electricity rates and tariff structures, natural gas prices, and site-specific conditions (i.e. space availability and integration into existing thermal and electric systems, permitting, siting and grid interconnection requirements) all contribute to the unique economics of each CHP system. An estimate of economic potential by system size range was developed for this analysis using Oregon-specific electricity and natural gas rates and representative CHP equipment cost and performance characteristics. Simple yearly paybacks were calculated for the five CHP system size categories for all of the applications.

The payback calculation was conducted for each electric utility in the state and the potential in terms of megawatts was categorized into four payback categories representing the degree of economic potential:

- Strong potential – simple payback < 5 years
- Moderate potential – simple payback 5 to 10 years
- Minimal potential – simple payback 10 to 20 years
- No potential – simple payback > 20 years

Table 17 presents the economic potential based on current electricity and natural gas prices, and equipment cost and performance characteristics. As shown, 87 MW of the total technical potential of 1,457 MW has a payback less than 5 years, with all of this potential occurring in Portland General Electric service territory. Just over 230 MW has a payback in the 5 to 10 year range. The majority of the sites with payback under 10 years are large sites in the >20 MW size range.

Table 17 – CHP Economic Potential in Oregon by Electric Utility

	Payback (years)				
Electric Utility	**<5**	**5 - 10**	**10 - 20**	**>20**	**Total**
Portland General Electric	87	134	29	364	614
Pacific Power & Light	0	98	169	204	471
Eugene Water & Electric Board	0	0	0	84	84
Other	0	0	0	289	289
Total	87	232	198	940	1,457

Table 18 shows the WHP economic potential based on WHP cost and performance characteristics and similar electricity and natural gas price assumptions used in the CHP economic potential analysis. While the total WHP technical potential is less than 3% of the CHP technical potential, the majority of the WHP economic potential has an expected payback of less than 5 years. None of the WHP systems have an expected payback of greater than 20 years, which contrasts with the 940 MW of CHP potential that has an expected payback of greater than 20 years.

Table 18 – WHP Economic Potential in Oregon by Electric Utility

Electric Utility	Payback (years)				Total
	<5	5 - 10	10 - 20	>20	
Portland General Electric	2.9	0.0	0.3	0.0	3.2
Pacific Power & Light	18.3	4.1	1.7	0.0	24.1
Eugene Water & Electric Board	0.0	0.0	0.0	0.0	0.0
Other	4.1	6.3	4.8	0.0	15.2
Total	25.3	10.4	6.8	0.0	42.4

CHP Market Penetration Analysis

Based on the calculated economic potential, a market diffusion model is used to determine the cumulative CHP market penetration over the analysis timeframe. The market penetration represents an estimate of CHP capacity that will actually enter the market between 2014 and 2030. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

Rather than use a single yearly payback value as the sole determinant of economic potential, the market acceptance rate has also been included. These acceptance rates are based on a survey of commercial and industrial facility operators, identifying the level of payback required to consider installing CHP. Figure 4 shows the percentage of survey respondents that would accept CHP investments at different payback levels[7]. As can be seen from the figure, more than 30% of customers surveyed would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of around 50 percent. Potential explanations for rejecting a project with such high returns include 1. The average customer does not believe that the results are valid and is attempting to mitigate this perceived risk by requiring very high projected returns before a project would be accepted, 2. The facility has limited capital and is rationing its ability to raise capital for higher priority projects (i.e. market expansion, product improvement, etc.).

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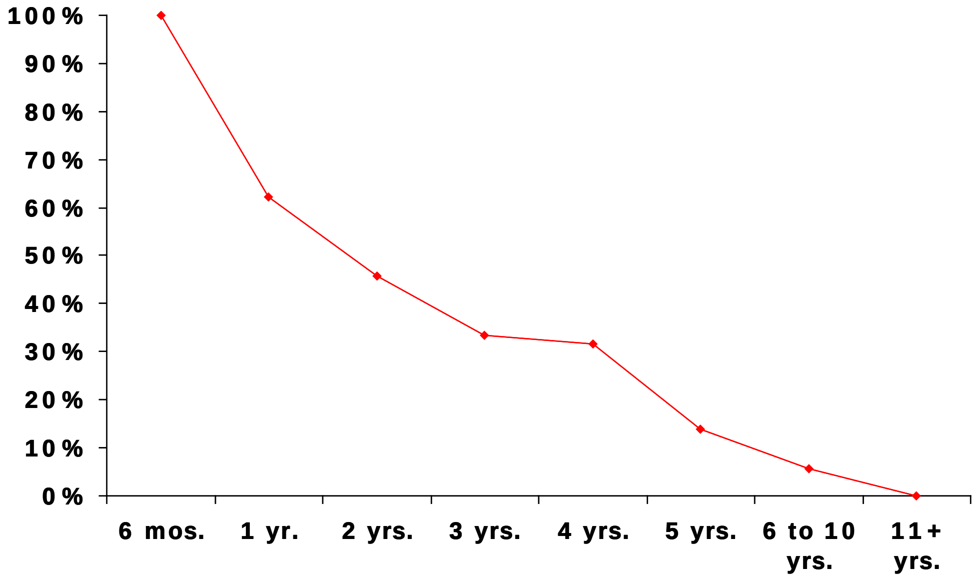
[7] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

Figure 4 - Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the CHP market penetration represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic potential section.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration over the analysis timeframe. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The shape of the curve is determined by an initial market penetration estimate and growth rate of the technical market potential.

CHP Market Penetration Results

Only Portland General Electric and Pacific power show economic CHP market penetration between 2014 and 2030. About 90.4 MW of CHP is forecasted to be installed, with 44.7 MW occurring in Portland General Electric territory and 45.7 MW occurring in Pacific Power territory. Sites in Eugene Water & Electric Board and other utility territories in Oregon do not show any economic CHP market penetration.

Figure 5 shows the projected CHP penetration rate over the analysis timeframe. Table 19 shows the detailed cumulative results for the state projections of CHP market penetration.

Figure 5 – CHP Cumulative Market Penetration by Electric Utility Territory, 2014-2030

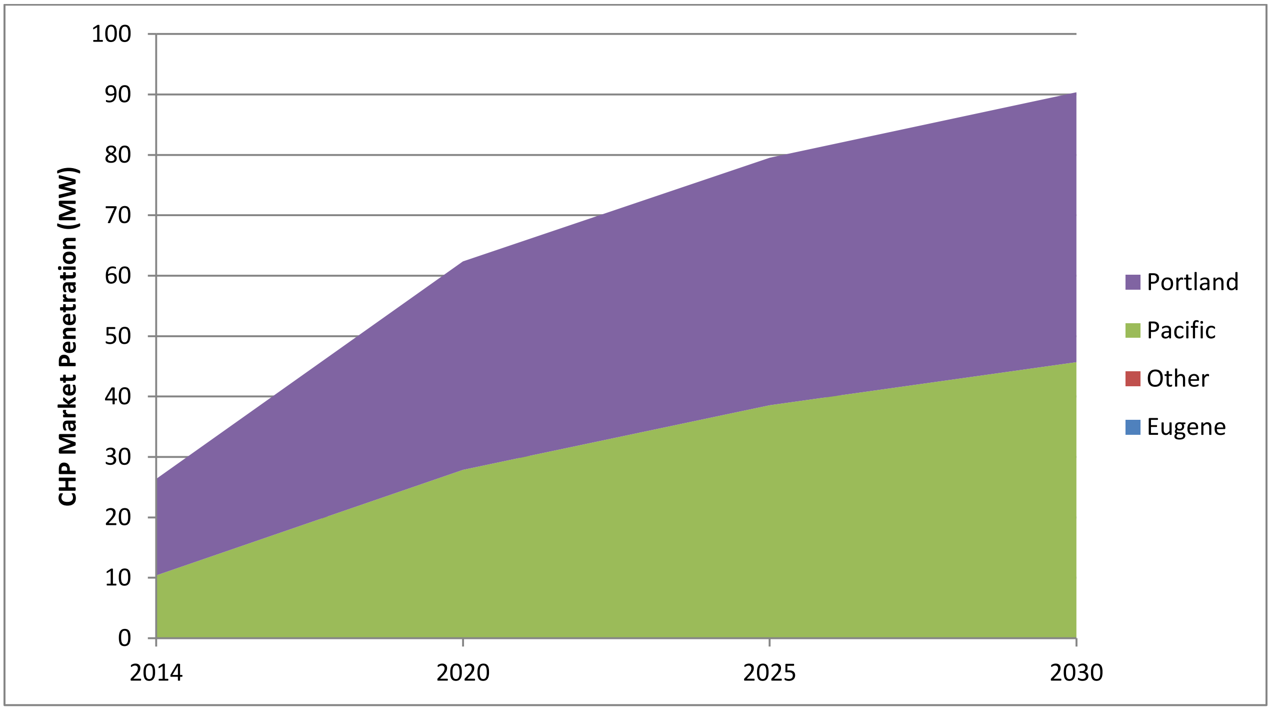


Table 19 – Oregon CHP Market Penetration Results

Cumulative Market Penetration (MW)	**2014**	**2020**	**2025**	**2030**
Industrial	26.2	61.7	78.5	89.2
Commercial/Institutional	0.2	0.7	1.0	1.2
Total	26.4	62.4	79.5	90.4

Annual Electric Energy Generation (Million kWh)	**2014**	**2020**	**2025**	**2030**
Industrial	209	489	619	703
Commercial/Institutional	1	5	7	8
Total	210	494	627	711

Annual CHP Fuel Balance (Billion Btu/year)	**2014**	**2020**	**2025**	**2030**
CHP Fuel	1,951	4,531	5,714	6,465
Avoided Boiler Fuel	843	1,922	2,418	2,736
Incremental Onsite Fuel	1,108	2,609	3,296	3,729

Cumulative Market Penetration by Size (MW)	**2014**	**2020**	**2025**	**2030**
50-500 kW	0.0	0.0	0.0	0.2
500 kW-1,000kW	0.0	0.0	0.0	0.2
1-5 MW	1.7	7.4	11.0	12.4
5-20 MW	0.8	1.9	4.4	6.0
>20 MW	23.9	53.1	64.1	71.6
Total Market	26.4	62.4	79.5	90.4

WHP Market Penetration Results

The total amount of expected WHP market penetration is 9.5 MW, with the majority of this located in Pacific Power & Light’s service territory. There is no technical potential for WHP applications in Eugene Water & Electric Board service territory. The WHP market penetration methodology is calculated consistently with the CHP methodology.

Table 19 – Oregon WHP Market Penetration

Utility Territory	**Market Penetration (MW)**
Portland General Electric	0.7
Pacific Power & Light	6.9
Other Electric Company	1.9
Total	9.5

Prioritization of CHP Opportunities

The below prioritized list of CHP opportunities in Oregon are based on the following criteria:

1) The technical potential for CHP (both traditional and waste heat to power) by SIC code;
2) The economic potential for CHP (both traditional and waste heat to power) by SIC code;
3) Economic development of Oregon industry (both job creation and preservation);
4) Recognition of facilities (industrial, commercial, institutional) with critical power loads
5) Reduced need for transmission and distribution upgrades ("non-wires solution";
6) Renewable CHP potential to offset "coal by wires", support forest health and where only fuel oil or propane is available for thermal energy needs (natural gas is not available); and
7) Environmental improvements

It is recognized that these recommendations are based on "best analytical judgment". Other choices could be made. The recommended priority areas and rationale are as follows:

1) Pulp & paper – A large target market opportunity with renewable energy CHP potential with job creation and preservation – 281.2 MW technical CHP potential;
2) Lumber and wood (forest products – A large target market opportunity with renewable energy CHP potential with job creation and preservation – 252.7 MW technical potential;
3) Chemicals – A large target market opportunity with job creation and preservation – 113.4 MW technical potential;
4) Food processing - A large target market opportunity with job creation and preservation – 111.3 MW;
5) Support of very large individual CHP systems – Greater than 100 MW – Transmission and distribution system support; and
6) Critical facilities (hospitals, nursing homes, waste water treatment facilities, prisons and data centers and places of refuge) – Serious consequences for loss of power, adding resiliency – At least 108.5 MW technical potential.

Note: Environmental improvements apply to all CHP systems.

Conclusion

Of the 1,457 MW existing CHP technical potential for CHP in Oregon, 319 MW has economic potential with a payback of less than 10 years. The 319 MW of economic potential is located only in Pacific Power & Light and Portland General Electric territory. Economic potential is determined by calculating payback, which takes into account: 1. Electric rate analysis by utility, system size, and market sector, for both standard customers and CHP customers, 2. EIA natural gas prices (2013 Oregon commercial, industrial, and citygate) by CHP system size, 3. Current and expected CHP cost and performance characteristics by technology type for various CHP sizes. Generally, calculated payback is lower for larger customers, stemming from lower CHP system costs as a result of economies of scale, better CHP system performance characteristics, and lower natural gas prices.

The 319 MW of CHP economic potential with a payback of less than 10 years is then pared down to CHP market penetration. There is 90.4 MW of cumulative CHP market penetration by 2030 in Oregon, also exclusively in the Pacific Power & Light and Portland General Electric service territories. Market penetration includes growth of technical potential to 2030, the customer payback acceptance curve, as well as the bass diffusion curve.

In addition, there is 42.4 MW of current WHP technical potential. With the exception of a few landfill WHP site, all other WHP sites are at least 1 MW in size, which implies more favorable economics than systems smaller than 1 MW. The majority of the WHP potential (i.e. 25.3 MW of 42.4 MW) has a payback of < 5 years, and the total expected market penetration is 9.5 MW. This yields a total CHP and WHP expected market penetration of 132.8 MW.

While these calculated economic potential and market penetration figures provide insight into the amount of CHP and WHP that could penetrate the market in Oregon, there are other factors and uncertainties that affect the economics expected market penetration. Some of these factors include:

- Local state or utility-specific incentives have not been included (however, the Federal Investment Tax Credit is included).
- Gas rates, especially for larger (i.e. > 20 MW) customers, can be negotiated on a case-by-case basis with the utility, generally resulting in more favorable rates for the customer.
- Some customers may accept a CHP or WHP system with a payback of more than 10 years.

Overall, multiple factors point toward increasing levels of distributed generation market penetration in the United States. Some of these factors include the abundance of low-cost natural gas, technology advancements, emissions compliance, as well as favorable policies and incentives. CHP will continue to play an important role meeting demands for distributed generation, particularly in applications with favorable electric and thermal loads. With more than 2,800 MW of existing CHP in Oregon, it is not unexpected that there will be significant levels of CHP and WHP market penetration in the near future.

APPENDIX K. Characterization of Supply-Side Options (Black & Veatch)

FINAL

CHARACTERIZATION OF SUPPLY-SIDE OPTIONS

B&V PROJECT NO. 188349
B&V FILE NO. 40.0000

PREPARED FOR

Portland General Electric

Portland General Electric

5 NOVEMBER 2015

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1.0 Introduction

Black & Veatch has prepared this report characterizing supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs requested by PGE include the following:

- 1x0 General Electric (GE) LMS100PA Combustion Turbine Generator (CTG).
- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG Reciprocating Engines (RICE).
- 1x1 Mitsubishi Hitachi Power Systems (MHPS) M501GAC Fast Combined Cycle (CCCT).
- 1x1 GE 7HA.01 CCCT.
- 2x1 GE 7HA.01 CCCT.
- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).
- Pumped Storage Hydroelectric (300 MW Closed Loop).
- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 40 MWh Redox Flow Battery).

Each of these technology options is described in the following sections, including a brief technology overview and characterization of the performance and cost parameters. A full matrix of cost and performance parameters for the 11 requested SSOs is provided as Appendix A. Expenditure patterns for each SSO are provided in Appendix B. A Technology Maturity Outlook for each SSO, described further in Subsection 2.5.4 is included in Appendix C.

2.0 Design Basis and General Assumptions

2.1 DESIGN BASIS FOR SUPPLY-SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch worked with PGE to establish design basis parameters for each of the SSOs under consideration. The design basis parameters are summarized in Table 2-1.

Table 2-1 Design Basis for Supply-Side Options

SUPPLY-SIDE OPTION	MAJOR EQUIPMENT	DUTY	NET CAPACITY (MW)	CAPACITY FACTOR (PERCENT)	PRIMARY FUEL
1x0 GE LMS100	Combustion Turbine: GE LMS100 PA Wet Intercooler (IC) Emissions Control: Selective Catalytic Reduction (SCR), Carbon Monoxide (CO) Catalyst, Water Injection for NOx Control Heat Rejection: Wet Cooling Tower	Peaking	100	21	Natural Gas
1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO Catalyst	Peaking	230	21	Natural Gas
6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO Catalyst	Peaking	110	13	Natural Gas
1x1 MHPS M501GAC Fast	Combustion Turbine: MHPS M501GAC Fast Duct Firing: None Emissions Control: SCR, CO Catalyst Heat Rejection: Wet Cooling Tower	Intermediate	365	71	Natural Gas
1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO Catalyst Heat Rejection: Wet Cooling Tower	Intermediate	400	71	Natural Gas
2x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO Catalyst Heat Rejection: Wet Cooling Tower	Intermediate	810	71	Natural Gas
Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: Selective Non-Catalytic Reduction (SNCR), Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	85	Wood
Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	85	n/a
Pumped Storage Hydro	System: Closed Loop Discharge Duration: 8 hours Upper Reservoir: 2,500 ft. Lower Reservoir: 1,000 ft.	Storage	300	n/a	n/a
Battery Storage	Battery: Lithium Ion Discharge Duration: 2 hours	Storage	50	n/a	n/a
Battery Storage	Battery: Redox Flow Discharge Duration: 4 hours	Storage	10	n/a	n/a

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, Black & Veatch worked with PGE to establish the following general site assumptions for the SSOs:

- The 1x0 GE LMS100, 1x0 GE 7F.05, and 6x0 Wartsila 18V50SG capital and O&M cost estimates are for add-on units to existing PGE combined cycle or thermal plant sites. All other option cost estimates are for greenfield sites.
- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, service, and fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water, if required, will be treated sewage effluent or groundwater. Allowances for pipeline costs are included in the Owner's cost.
- Costs for transmission lines and switching stations are included as part of the Owner's cost estimate.

2.3 CAPITAL COST ESTIMATING ASSUMPTIONS

Black & Veatch worked with PGE to establish the following capital cost estimating assumptions for the SSOs:

- Capital cost estimates were developed on an engineering, procurement, and construction (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- All capital cost estimates are presented in 2015 dollars.
- EPC capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest, or other general Owner's cost items.
- Separately from the EPC capital cost estimates, a recommended allowance for Owner's costs has been provided for each technology. Potential Owner's costs are listed in Table 2-2.

Table 2-2 Potential Owner’s Costs for Power Generation/Storage Projects

Project Development

- Site selection study
- Land purchase/rezoning for greenfield sites
- Transmission/gas pipeline right-of-way
- Road modifications/upgrades
- Demolition
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance
- Provision of project management

Spare Parts and Plant Equipment

- Combustion turbine and reciprocating engine materials, gas compressors, supplies, and parts
- Steam turbine materials, supplies, and parts
- Boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishings and supplies

Plant Startup/Construction Support

- Owner’s site mobilization
- Operations and Maintenance (O&M) staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals and reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchases
- Acceptance testing
- Construction all-risk insurance

Owner’s Contingency

- Owner’s uncertainty and costs pending final negotiation
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreements (i.e., interconnection contract costs)

Owner’s Project Management

- Preparation of bid documents and the selection of contractors and suppliers
- Performance of engineering due diligence
- Provision of personnel for site construction management

Taxes/Advisory Fees/Legal

- Taxes
- Market and environmental consultants
- Owner’s legal expenses
- Interconnect agreements
- Contracts (procurement and construction)
- Property

Utility Interconnections

- Natural gas service
- Gas system upgrades
- Electrical transmission
- Water supply
- Wastewater/sewer

Financing (included in fixed charge rate)

- Financial advisor, lender’s legal, market analyst, and engineer
- Loan administration and commitment fees
- Debt service reserve fund

2.3.2 Direct Cost Assumptions

Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services. Assumptions regarding direct costs within the capital cost estimates include the following:

- Construction costs are based on a turnkey EPC contracting philosophy.
- Permitting and licensing are excluded from EPC costs. These items should be included in the Owner's cost estimate.

2.3.3 Indirect Cost Assumptions

Indirect costs within the capital cost estimates are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

Indirect costs are assumed to exclude the following:

- Initial inventory of spare parts for use during operation. These items are assumed to be included in the Owner's costs.
- Allowance for funds used during construction and financing fees. These costs should be included in the Owner's overall cost estimate.

2.4 OPERATION AND MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch.
- O&M cost estimates were categorized into fixed O&M and nonfuel variable O&M components. Nonfuel variable O&M costs exclude the cost of fuel (e.g., natural gas or woody biomass). Depending upon the SSO, fuel may or may not be required.
  - Fixed O&M costs include labor (operations, maintenance, technical services, and administration), routine maintenance (major equipment and

systems, including contracted services) and other expenses (training, office and administrative expenses, bonus and incentives, and miscellaneous). Options assumed to operate as peaking units have minimal staff, assumed to be shared with staffing at an existing, adjacent facility. Costs are presented in $/MW-month.

  - Nonfuel variable O&M costs include outage maintenance, parts and materials, water usage, chemical usage and equipment. Costs are presented in $/MWh.
- Nonfuel variable wear and tear costs and nonfuel startup variable O&M costs are presented as sub-categories of nonfuel variable O&M costs and are defined as follows:
  - Nonfuel variable wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG when applicable, and SCR catalysts. Costs are presented in $/MWh.
  - Nonfuel startup variable O&M costs assume an average start and include makeup water and chemicals. This estimate does not include fuel or electricity. Costs are presented in $/start.
- All nonfuel O&M cost estimates are presented in 2015 dollars.
- Additionally, Black & Veatch provided estimates of fuel startup variable O&M Usage presented in million British thermal units (MMBtu)-HHV/start.

2.5 ADDITIONAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including overnight total cost standard deviation, capital expenditures and maintenance accruals, decommissioning costs, and a technical maturity outlook. A brief description of the methodology applied for each of these financial parameters is described in the following subsections.

2.5.1 Overnight Total Cost Standard Deviation

One standard deviation accounts for approximately 68.2 percent of the data points for a given data set, assuming a normal distribution. Given the planning level of this IRP study, Black & Veatch assumed a normal distribution and estimated the standard deviation by comparing the technology options on a relative basis. The standard deviation estimates are based on expert judgment and were based on Black & Veatch project experience with units of similar size and type, where possible.

2.5.2 Capital Expenditures/Maintenance Accruals

Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). For example, the operation of a geothermal facility typically requires the drilling of new supply wells at regular intervals during the lifetime of the power project, and depending on the extent of charge/discharge cycling, battery energy storage systems may require periodic replacement of batteries.

Typically, Black & Veatch does not provide estimates of the costs associated with these activities as capital expenditures or maintenance accruals separately from other O&M costs. In instances where these periodic costs are necessary (for the SSOs under consideration in this report, excluding battery energy storage systems), these costs have been included in the relevant O&M costs associated with specific technology options. For these SSOs, the periodic system/equipment replacement requirements are noted in the technology-specific assumptions.

2.5.3 Decommissioning Costs

The total estimated decommissioning cost is presented in 2015 USD based on a percentage of the total overnight capital cost. Relative percentages are based on recent decommissioning cost estimates for a similar scope of decommissioning for similar assets and Black & Veatch expert judgment. Values are net of salvage.

Typically, a fixed amount of money is accrued each year over the book life of the asset to cover the cost of decommissioning the asset. For all SSOs except Pumped Storage Hydro, it is assumed the site would be returned to a brownfield condition at the end of its book life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).

2.5.4 Technology Maturity Outlook

To provide an outlook on technology maturity and the potential for reductions in future capital costs, Black & Veatch employed a methodology for estimating future costs associated with each of the SSOs considered in this study. To provide this technology maturity outlook, Black & Veatch employed data developed by the US Department of Energy (US DOE) Energy Information Administration (EIA) in the Annual Energy Outlook (AEO) 2014 and applied these data to the present-day capital costs for each SSO. For the data developed for the AEO 2014, EIA employs the National Energy Modeling System (NEMS). Black & Veatch has provided estimates of total capital cost from 2015 to 2035. All estimates of future capital costs are presented on a constant dollar basis (i.e., in 2015 dollars).

2.5.4.1 NEMS Attributes

Relative strengths of the NEMS estimates of future capital costs for generation technologies include the following:

- NEMS was first developed in 1993 and has been employed by the EIA since then to provide a basis for the AEO. The model employs an analytical methodology; is well-documented, and has been peer reviewed over the course of time.
- NEMS is one of the more commonly used methods for future capital cost forecasting.
- The forecast data provided by NEMS provide technology-specific forecasts for the majority of technologies of interest, and forecast data is provided on a year-by-year basis from 2015 to 2040, which is consistent with the time horizon considered in this study.
- Within the NEMS model, future cost forecasts are developed and updated annually, rather than on cycles of multiple years (i.e., 2 to 5 years).
- The estimates are developed by the US DOE rather than national laboratories and technology-specific advocacy groups. In many cases, the national laboratories advocacy groups have a specific area of technical focus. The estimates developed by US DOE utilize information provided by the laboratories and other groups but are considered to have less technology bias than estimates developed by others.

Relative weaknesses of these estimates include the following:

- NEMS is a model of the energy market within the United States, and no model is able to fully integrate and consider all factors that affect costs of generation assets. The model may not predict short-term market effects. For example, the NEMS model did not forecast the increase in capital costs of all generation facilities in the 2005 to 2009 time period, which was attributed to (1) short-term shortage in craft labor supply and (2) short-term increases in commodity prices. While virtually all forecast models are limited in their ability to predict these short-term variations, the NEMS model is considered to provide a general indication of price trends over the long term.
- The NEMS model assumes continual development for all technologies, which may not be the case, particularly for technologies that are mature from a technical perspective. For example, coal fired boiler, simple cycle turbine and reciprocating engine technologies are unlikely to see significant reductions in cost.

Given these considerations, the NEMS forecast of future capital cost is useful as a means to quantify general capital cost trends for the disparate set of generation options available to utilities. These trends provide a reasonable base case for future capital costs, and variations for specific technologies may be considered via sensitivity analysis, if necessary. For example, for emerging technologies such as battery energy storage, analysis of variations in forecasts may be beneficial.

2.5.4.2 Estimated Future Capital Costs for PGE IRP 2016

As part of the NEMS data within the AEO 2014, EIA developed forecasts of capital cost (over the 2014 to 2040 time period) for technologies as listed in Table 2-3. Black & Veatch requested data associated with these forecasts, and EIA provided the data via email in April 2015. The data provided by EIA includes the overnight capital costs for these technologies presented in 2012 dollars (on a $/kW basis). Based on notes from EIA, these data represents the "cost of new plants, including contingencies, excluding regional multipliers, excluding tax credits."

Table 2-3 Technologies Included in NEMS Data Provided by EIA

CONVENTIONAL TECHNOLOGIES	RENEWABLE TECHNOLOGIES	DISTRIBUTED GENERATION TECHNOLOGIES
• Pulverized Coal • Integrated Gasification Combined Cycle (IGCC) • Pulverized Coal with Sequestration • Combustion Turbine • Advanced Combustion Turbine • Combined Cycle • Advanced Combined Cycle • Advanced Combined Cycle ith/ Sequestration • Fuel Cell • Nuclear • Hydroelectric	• Biomass • Geothermal • Landfill Gas • Hydroelectric • Wind (Onshore) • Offshore Wind • Solar Thermal • Solar Photovoltaic (PV)	• Distributed Generation Base • Distributed Generation Peak

Maintaining a constant dollar basis, Black & Veatch developed a set of “forecast factors,” and normalized these factors to 2015 values for each technology presented in the NEMS overnight capital cost data. The resulting forecast factors for conventional technologies, including nuclear, are illustrated in Figure 2-1. The forecast factors for renewable technologies, including fuel cell and distributed generation technologies, are illustrated in Figure 2-2. A table of these NEMS-based forecast factors for conventional and renewable technologies is presented in Appendix C.

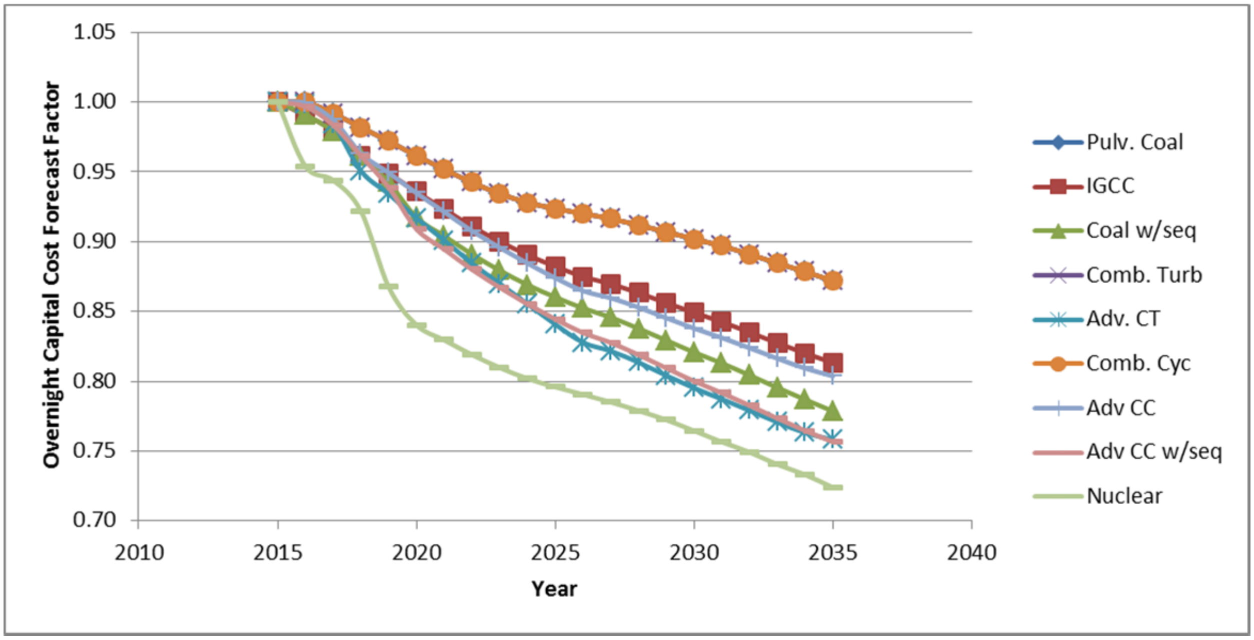

Figure 2-1 Overnight Capital Cost Forecast Factors for Conventional Technologies

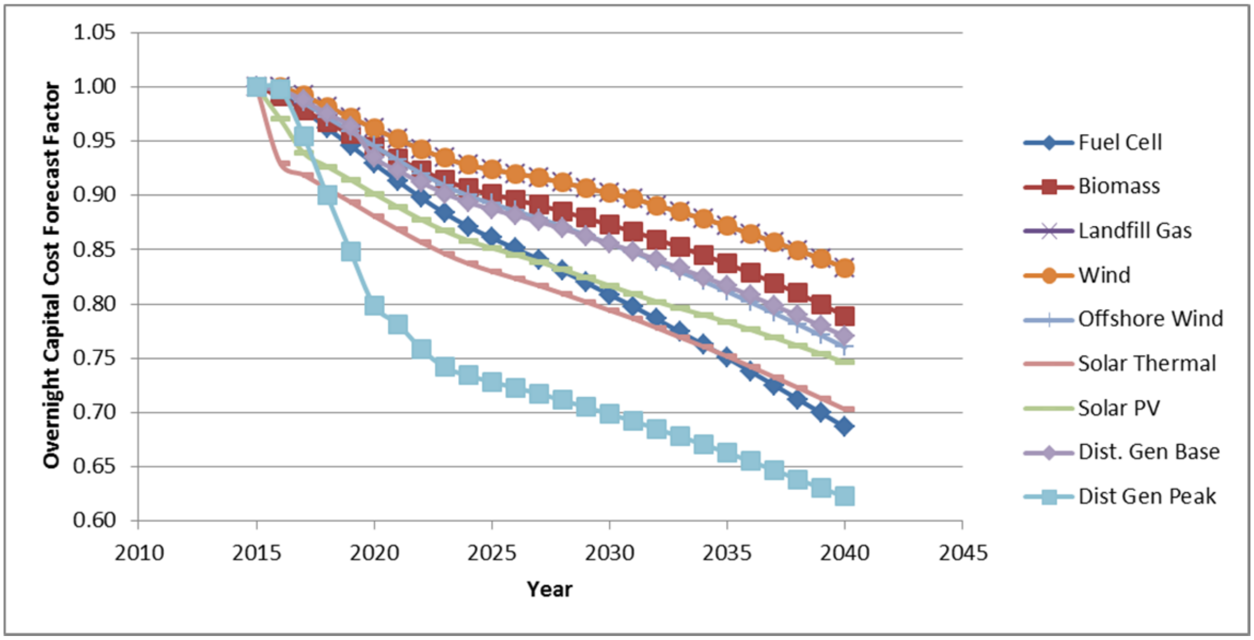

Figure 2-2 **Overnight Capital Cost Forecast Factors for Renewable Technologies**

For the SSOs considered in this IRP study, the estimates of future capital costs were based on the corresponding technology forecast factors (based on NEMS data). The future capital cost for each SSO was estimated by multiplying the present-day total overnight capital cost by the appropriate technology forecast factor. For example, the future capital costs of the simple cycle GE LMS100 SSO were based on the set of forecast factors associated with the NEMS data for combustion turbine technologies. To estimate the total capital cost in a specific year (in 2015 dollars), the present-day capital cost (in 2015 dollars) was multiplied by the combustion turbine forecast factor associated with the specified year. The NEMS technology forecast factors applied for each SSO are identified in Table 2-4.

Table 2-4 Technology-Specific Forecast Data Employed for Supply-Side Options

SUPPLY-SIDE OPTION	EIA NEMS TECHNOLOGY FORECAST EMPLOYED
1x0 GE LMS100	Combustion Turbine
1x0 GE 7F.05	Combustion Turbine
6x0 Wartsila 18V50SG	Combustion Turbine
1x1 MHPS M501GAC Fast	Combined Cycle
1x1 GE 7HA.01	Advanced Combined Cycle
2x1 GE 7HA.01	Advanced Combined Cycle
Biomass Combustion	Biomass
Geothermal – Binary	Biomass[1]
Pumped Storage Hydro	Biomass[1]
Battery Storage – Li-Ion	Not Applicable[2]
Battery Storage – Redox Flow	Not Applicable[2]

Notes:

1. For Geothermal and Pumped Storage Hydro SSOs, Black & Veatch considered these to be technologically mature renewable options, similar in terms of future capital cost outlook to biomass SSOs.
2. Expected trends for battery energy storage options are not consistent with any of the technology forecasts provided within the EIA data. Therefore, for battery storage applications, Black & Veatch developed a separate estimate of future capital costs.

2.5.4.3 Other NEMS Characteristics

Regarding the NEMS technology data applied to each SSO, Black & Veatch notes the following:

- While the NEMS data included geothermal and hydroelectric cost data, Black & Veatch notes that this data was not presented in the same fashion as other technologies within the data provided by EIA. The costs for geothermal and hydroelectric provided by EIA had significant fluctuations from year to year. According to EIA staff, capital costs for geothermal and hydroelectric technologies were determined by selecting projects from within a database of existing sites with site-specific costs.[1]

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[1] In an email to Black & Veatch, Laura Martin of the Electricity Analysis Team at EIA stated: “Reflected in the [geothermal and hydroelectric technology] costs I provided you are just the least-cost plants available each year, based on the model results in that scenario. Within the model we develop a supply curve of capacity and costs for the technology, and pass the electricity model information about the most economic sites (looking at total operating costs, not just capital costs) and the model makes decisions about whether or not to build. As sites are chosen, the supply curves are readjusted each year, and the overnight costs associated with the cheapest ‘total cost’ site may jump around.”

  - Because the NEMS capital cost data for geothermal and hydroelectric technologies did follow a consistent trend, Black & Veatch did not apply these forecasts to geothermal and hydroelectric options considered in this study.
  - Because both geothermal and pumped storage hydroelectric are considered technologically mature renewable/storage options, Black & Veatch applied forecast factors associated with Biomass technologies, which are also considered to be a technologically mature renewable technologies.
- For utility-scale battery energy storage technologies, none of the technologies included in the NEMS data were considered consistent with anticipated capital costs over the next 25 years. Therefore, Black & Veatch developed a set of capital cost forecast factors for battery energy storage technologies, as shown in Figure 2-3.
  - Black & Veatch anticipates that capital costs associated with battery energy storage facilities may decrease by 50 percent (on a constant dollar basis) by 2025.
  - From 2025 to 2035, Black & Veatch anticipates that capital costs of battery energy storage facilities may remain flat (on a constant dollar basis).
  - The estimates of future costs for utility-scale battery are consistent with DOE targets for cost reductions associated with battery technologies through 2025 and longer term projections by industry analysts.

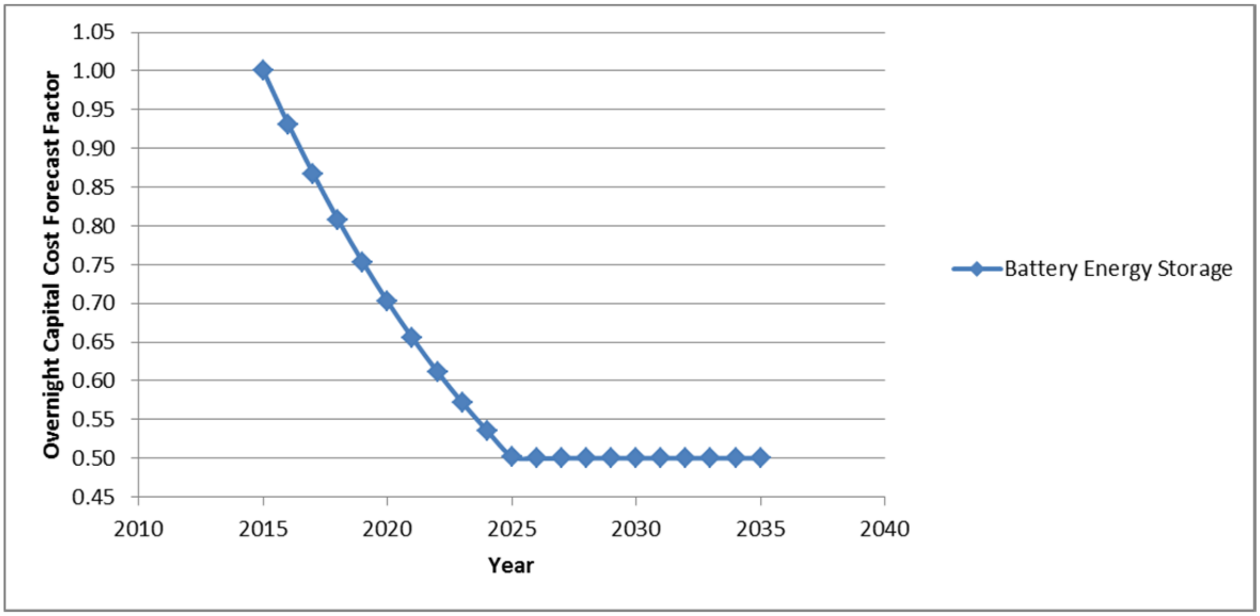

Figure 2-3 **Overnight Capital Cost Forecast Factors for Battery Energy Storage Supply-Side Options**

3.0 Conventional Generation Options

Six conventional generation SSOs were studied.

- 1x0 GE LMS100PA CTG.
- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG RICE.
- 1x1 MHPS M501GAC Fast CCCT.
- 1x1 GE 7HA.01 CCCT.
- 2x1 GE 7HA.01 CCCT.

These conventional SSOs and their performance and cost characteristics are defined in the following subsections. A comparison of wet versus dry cooling is provided in Subsection 3.7.

3.1 1X0 GE LMS100PA

3.1.1 Technology Overview

The LMS100PA is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor section. A compressed air and fuel mixture is combusted in a single annular combustor. Hot flue gas then enters the two-stage high-pressure turbine. The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine, which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to/from the intercooler and the intercooler. Nitrogen oxides (NO_x) emissions are minimized utilizing water injection.

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of ~41:1. The single annular combustor is derived from GE's LM6000 aeroderivative and CF6-80C aircraft engines. The high-pressure turbine is derived from GE's LM6000 aeroderivative and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 megawatt per minute (MW/min) ramp rate.
- 10 minutes to full power.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 850 pounds per square inch gauge (psig).
- Dual fuel capable.

The LMS100 is available in a number of configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and dry low emissions (DLE) in lieu of water injected combustion for applications when water availability is limited.

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle natural gas-fired GE LMS100PA combustion turbine facility. Relevant assumptions employed in the development of performance and cost parameters for the LMS100PA facility include the following:

- The power plant would consist of a single GE LMS100PA CTG, located outdoors in a weather-proof enclosure.
- To reduce NOx and carbon monoxide (CO) emissions, a selective catalytic reduction (SCR) system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and when CTG exhaust temperature approaches the operational limits of the SCR catalyst.
- Intercooler heat is rejected to atmosphere by way of a wet mechanical draft cooling tower.
- A generation building would house electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compressors would be housed in a prefabricated weather-proof enclosure.

3.2 1X0 GE 7F.05

3.2.1 Technology Overview

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's 5th generation 7FA machine with the latest advancements including a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 MW/min ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes.
- Natural gas interface pressure requirement of only 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Water injected combustion with CTG NOx emissions of 42 ppm on diesel fuel.
- High exhaust temperature makes it difficult to implement post-combustion NOx emissions controls.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle natural gas-fired GE 7F.05 combustion turbine facility. Relevant assumptions employed in the development of performance and cost parameters for the 7F.05 facility include the following:

- The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and to reduce CTG exhaust temperature to within the operational limits of the SCR catalyst.
- A generation building would house electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- No natural gas compression has been assumed for this option.

3.3 6X0 WARTSILA 18V50SG

3.3.1 Technology Overview

The 18V50SG is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. Individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been at least 62 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere by way of a mechanical draft cooling tower. In locations with limited water resources, an air-cooled heat exchanger may be employed as an alternative to a mechanical draft cooling tower. An 18V50SG power plant utilizing air cooled heat exchangers would require very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 10 minutes to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a “6-Pack”. The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle (6x0) natural gas-fired Wartsila 18V50SG reciprocating engine facility. Relevant assumptions employed in the development of performance and cost parameters for the 18V50SG facility include the following:

- The facility would consist of six Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for water treatment, electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- An SCR system with oxidation catalyst would be utilized to minimize NOx and CO emissions.
- Engine heat is rejected to atmosphere by way of a common wet mechanical draft cooling tower.

3.4 1X1 MHPS M501GAC FASTTECHNOLOGY OVERVIEW

The MHPS 501GAC Fast is an air cooled heavy frame CTG with a single shaft, 17-stage axial compressor, 4-stage axial turbine, and 17-can-annular DLN combustors. The 501GAC Fast utilizes a single inlet guide vane stage to vary compressor geometry for part load operation. The 501GAC Fast is a variation of MHPS’s G-class technology. Improved thermal barrier coatings (TBC), more effective use of cooling air, and reduced air leakage have allowed for the steam-cooled M501G to evolve into the air cooled M501GAC. The M501GAC Fast has been specifically designed to be more flexible than the M501GAC with higher ramp rates and faster start times. The main difference between the M501GAC and M501GAC Fast is increased clearances in the first stages of the turbine. As a result, the M501GAC Fast does not encounter the same interference issues and can heat up much more quickly at the expense of CTG output and efficiency.

This option would also employ a triple-pressure heat recovery steam generator (HRSG), reheat condensing steam turbine generator (STG), wet surface condenser, and wet mechanical draft counterflow cooling tower. The STG would likely employ a single axial flow exhaust.

Key attributes of the MHPS M501GAC-Fast include the following:

- High availability.
- CTG 20 percent/min ramp rate (about 54 MW/min).

- Combined cycle start times dependent on bottoming cycle, HRSG, and STG design. A nominal hot start time of 60 minutes is typical.
- Natural gas interface pressure requirement of about 650 psig.
- Dual fuel capable, DLN combustion with CTG NOx emissions of 15 ppm on natural gas.

An off-engine heat exchanger, referred to as the Turbine Air Cooler (TCA), cools hot air from the compressor discharge indirectly with feedwater. The cooled compressor discharge air is sent to the first, second, and third stages of the turbine for blade cooling.

3.4.1 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a combined cycle natural gas-fired MHPS M501GAC Fast CTG-based facility. Relevant assumptions employed in the development of performance and cost parameters include the following:

- The power plant would consist of a single MHPS M501GAC Fast CTG, located outdoors in a weather-proof enclosure with close-coupled three-pressure HRSG.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, engine controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression has been assumed for this option.

3.5 1X1 GE 7HA.01

3.5.1 Technology Overview

The GE 7HA.01 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 4-stage axial turbine, and 12-can-annular DLN combustors. The 7HA.01 a single inlet guide vane stage and three variable stator vain stages to vary compressor geometry for part load operation. The 7HA.01, along with the scaled-up 7HA.02 and 50 Hertz versions, the 9HA.01 and 9HA.02, represent the largest and most advanced heavy frame CTG technologies from GE. The compressor design is scaled from GE’s 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 will use a DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees, stable operations, and allows for increased fuel variability. 7HA.01 first shipments are expected to begin in 2016. GE has 16 orders of its HA CTG technology to date.

This option would also employ a triple-pressure HRSG, reheat condensing STG, wet surface condenser, and wet mechanical draft counterflow cooling tower. The STG would likely employ a single axial flow exhaust.

Key attributes of the GE 7HA.01 include the following:

- High availability.
- CTG 50 MW/min ramp rate.
- Combined cycle start times dependent on bottoming cycle, HRSG, and STG design. A nominal hot start time of 60 minutes is typical.
- Natural gas interface pressure requirement of about 500 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.

3.5.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a combined cycle natural gas-fired GE HA.01 CTG-based facility. Relevant assumptions employed in the development of performance and cost parameters include the following:

- The power plant would consist of a single GE 7HA.01 CTG, located outdoors in a weather-proof enclosure with close-coupled three-pressure HRSG.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, engine controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression has been assumed for this option.

3.6 2X1 GE 7HA.01

This option would employ two GE 7HA.01 CTGs, two triple-pressure HRSGs, a single reheat condensing STG, wet surface condenser, and wet mechanical draft counterflow cooling tower. The STG would likely employ a two flow down or side exhaust. Refer to the 1x1 GE 7H.01 technology overview and technology-specific assumptions provided in Section 3.5.

3.7 WET VERSUS DRY COOLING COMPARISON

Combined cycle power plants and some peaking power plants require large heat rejection systems for proper operation. For a combined cycle power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature which results in a high bottoming cycle efficiency. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC which results in a lower bottoming cycle efficiency compared to a combination surface condenser and wet mechanical draft cooling tower. O&M costs required to maintain an air cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water treatment chemicals would likely offset the additional maintenance cost. Below is a summary comparison for a typical combined cycle operating during hot day conditions. The performance difference during average day conditions would be reduced.

Table 3-1 Typical Combined Cycle Wet versus Dry Cooling Comparison

	WET SURFACE CONDENSER/ WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED CONDENSER
Capital Cost	BASE	+5 percent
Net Plant Output	BASE	-1.5 percent
Net Plant Heat Rate	BASE	+1.5 percent

Some peaking plants also rely on large heat rejection systems for proper operation. GE's LMS100 uses a compressor intercooler to cool air leaving the low pressure compressor prior to entering the high pressure compressor. Using an air cooled intercooler loop is possible but results in a much greater hot day performance impact. Below is a summary comparison for an LMS100 operating during typical hot day conditions.

Table 3-2 Typical GE LMS100 Wet versus Dry Cooling Comparison

	WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED HEAT EXCHANGER
Capital Cost	BASE	+3 to 5 percent
Net Plant Output	BASE	-5 to 10 percent
Net Plant Heat Rate	BASE	+1 to 3 percent

Wartsila's 18V50SG also relies on a large heat rejection system, mainly for engine jacket cooling. Unlike the LMS100 or a combined cycle's bottoming cycle, the temperatures required are not as stringent. Therefore, the performance impact associated with an air cooled heat exchanger is not nearly as great. However, one thing to keep in mind is space availability. The footprint of an air cooled heat exchanger for a single Wartsila 18V50SG engine is roughly 100 feet by 100 feet, which is approximately the space required for the engine itself. One solution would be to locate the air cooled heat exchangers on top of the engine hall. Wartsila has done this as EPC contractor for projects outside the US. However, this approach will result in increased engine hall building costs. Below is a summary comparison for 18V50SG operating during typical hot day conditions.

Table 3-3 Typical Wartsila 18V50SG Wet versus Dry Cooling Comparison

	WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED HEAT EXCHANGER
Capital Cost	BASE	+2 to 5 percent
Net Plant Output	BASE	-1 to 3 percent
Net Plant Heat Rate	BASE	+1 to 2 percent

3.8 TECHNICAL AND FINANCIAL PARAMETERS FOR CONVENTIONAL GENERATION OPTIONS

Technical parameters for conventional energy options considered for PGE are summarized in Table 3-4, while cost and financial parameters for conventional energy options considered for PGE are summarized in Table 3-4 and Table 3-5.

Table 3-4 Technical Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/ MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	FUEL CONSUMPTION VERSUS OUTPUT (MMBtu-HHV VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIMES (HOURS)	START TIME TO FULL LOAD (MINS)[5]	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)[6]	EQUIVALENT FORCED OUTAGE RATE (PERCENT)	EPC PERIOD (MONTHS)[7]
1x0 GE LMS100	110	105	21	0.06	9,031	9,176	$y = 2.25579E-13x^{3} - 4.60425E-08x^{2} + 1.00877E-02x + 1.40587E+02$	30	50	0.5 / 0.5	10	0.38	0.07	2.1	24
1x0 GE 7F.05	230	224	21	0.04	9,843	9,981	$y = 1.49882E-14x^{3} + 1.36515E-08x^{2} + 1.41949E-03x + 1.02989E+03$	38	40	0.5 / 0.5	11	0	0.10	1.5	24
6x0 Wartsila 18V50SG	110	110	13	0.06	8,371	8,437	$y = -6.69785E-08x^{2} + 9.35009E-03x + 4.57192E+00$	7	31.8	0.5 / 0.5	10	0.36	0.20	3.2	24
1x1 MHPS M501GAC Fast	395	383	71	0.04	6,744	6,926	$y = -1.32139E-13x^{3} + 1.24103E-07x^{2} - 3.20871E-02x + 4.11935E+03$	58	54	1.5 / 1.5	Hot:60 Warm:100 Cold:210	1.84	0.84	2.9	30
1x1 GE 7HA.01	400	387	71	0.04	6,370	6,503	$y = -5.85279E-15x^{3} + 7.52543E-09x^{2} + 2.81340E-03x + 5.92389E+02$	33	50	1.5 / 1.5	Hot:60 Warm:100 Cold:210	1.86	1.23	2.9	30
2x1 GE 7HA.01	810	784	71	0.02	6,351	6,485	$y = -1.26147E-15x^{3} + 3.40328E-09x^{2} + 3.00625E-03x + 1.14354E+03$	16	100	1.5 / 1.5	Hot:60 Warm:100 Cold:210	3.71	1.23	2.9	34

Notes:

1. Performance parameters assume International Organization for Standardization (ISO) conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is fuel consumption versus output (MMBtu-HHV versus kW-net, new and clean). Heat rate can be further determined by dividing fuel consumption by output.
4. While maintaining emissions compliance for combustion turbine and reciprocating engine based option.
5. Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).
6. Maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance.
7. The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.

Table 3-5 Financial Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	DESIGN LIFE (YEARS)	EXPENDITURE PATTERN (BY MONTH)	OVERNIGHT EPC CAPITAL COST ($000, 2015$)	OWNER'S COST ALLOWANCE (PERCENT)[8]	OVERNIGHT TOTAL CAPITAL COST ($000, 2015$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2015$)	FIXED O&M COSTS ($/MW-MONTH)[9]	NONFUEL VARIABLE O&M COST (2015$/MWh)[9]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2015$/MWh)[10]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2015$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2015$/ START)[11]	FUEL STARTUP VARIABLE O&M COSTS (MMBTU-HHV/ START)[12]	DECOMMISSIONING COST ($000, 2015$)[13]
1x0 GE LMS100	30	Refer to Appendix B	99,000	25	123,800	9,300	267	5.22	3.88	Refer to Note 14	10	66	6,800
1x0 GE 7F.05	30	Refer to Appendix B	112,000	25	140,000	10,500	261	9.29	9.03	Refer to Note 14	4	294	7,700
6x0 Wartsila 18V50SG	30	Refer to Appendix B	128,000	25	160,000	12,000	280	8.93	5.43	Refer to Note 14	11	72	8,000
1x1 MHPS M501GAC Fast	30	Refer to Appendix B	342,000	25	427,500	42,800	744	3.00	1.94	Refer to Note 14	361	850	42,800
1x1 GE 7HA.01	30	Refer to Appendix B	349,000	25	436,300	43,600	688	2.60	1.60	Refer to Note 14	369	950	43,600
2x1 GE 7HA.01	30	Refer to Appendix B	623,000	25	778,800	77,900	502	2.29	1.55	Refer to Note 14	557	1,900	77,900

Notes (continued from Table 3-4):

8. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
9. Estimates expressed in terms of new and clean condition.
10. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG, and SCR catalysts, as applicable.
11. Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.
12. Startup fuel consumption for achieving CTG/RICE full load operation.
13. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
14. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary, these costs have been included in the relevant O&M costs associated with specific technology options.

4.0 Renewable Generation Options

Renewable SSOs considered include the following:

- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).

These renewable SSOs and their performance and cost characteristics are defined in the following sections.

4.1 BIOMASS COMBUSTION

4.1.1 Technology Overview

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is generated in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Boiler systems used in biomass combustion include stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Newly constructed biomass-fired generation facilities likely employ either a stoker boiler or a fluidized bed boiler. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are under development but have not achieved widespread commercial operation at utility scales.

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are less efficient than modern fossil fuel plants. Also, because of added transportation costs, biomass is generally more expensive than conventional fossil fuels on a $/kW basis. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment. Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike coal or natural gas, biomass may be viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury (Hg), cadmium, and lead.

While biomass fuels offer certain emissions benefits relative to coal and natural gas, biomass combustion facilities typically require technologies to control emissions of NO_x, particulate matter (PM), and CO to meet state and or federal regulatory requirements.

4.1.2 Technology-Specific Assumptions

For this PGE IRP effort, Black & Veatch developed performance and cost parameters for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler, with a net generation output of 35 MW-net. Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net biomass energy facility include the following:

- The primary fuel for the biomass facility will be woody biomass, with an average moisture content of 40 percent and an as-received heating value of 5,100 Btu/lb (HHV).
- The facility will have an average annual capacity factor of 85 percent. It is estimated that the facility would produce approximately 260,600 MWh per year of electricity.
- The facility will have a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes SCR systems for NOx control, sorbent injection for acid gas control, and a fabric filter for PM control.

4.2 GEOTHERMAL

4.2.1 Technology Overview

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine which lit four light bulbs. This experiment led to the installation of the world's first geothermal power plant in 1911, with a capacity of 250 kilowatts. The government of New Zealand was the first significant producer of geothermal electricity, with the ~150-MW Wairakei power plant, which began operating in 1958. Shortly thereafter, the first power plants were installed at The Geysers in California, USA. By 1975, the Larderello fields were capable of producing about 400 MW of power. By the mid-1980s, The Geysers' output had peaked at about 1,600 MW, after which it declined to its present output at about 850 MW.[2] Today, roughly 70 geothermal power facilities are in operation in over 20 countries around the world. There is a natural concentration of geothermal resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and The Philippines have many large, high-temperature geothermal resources; about 10,000 MW of geothermal capacity are installed worldwide.[3]

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality

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[2] Sanyal, S. K. (2011) Fifty Years of Power Generation at The Geysers - The Lessons Learned. Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering, Stanford University, January 31 - February 2, 2011, SGP-TR-191.

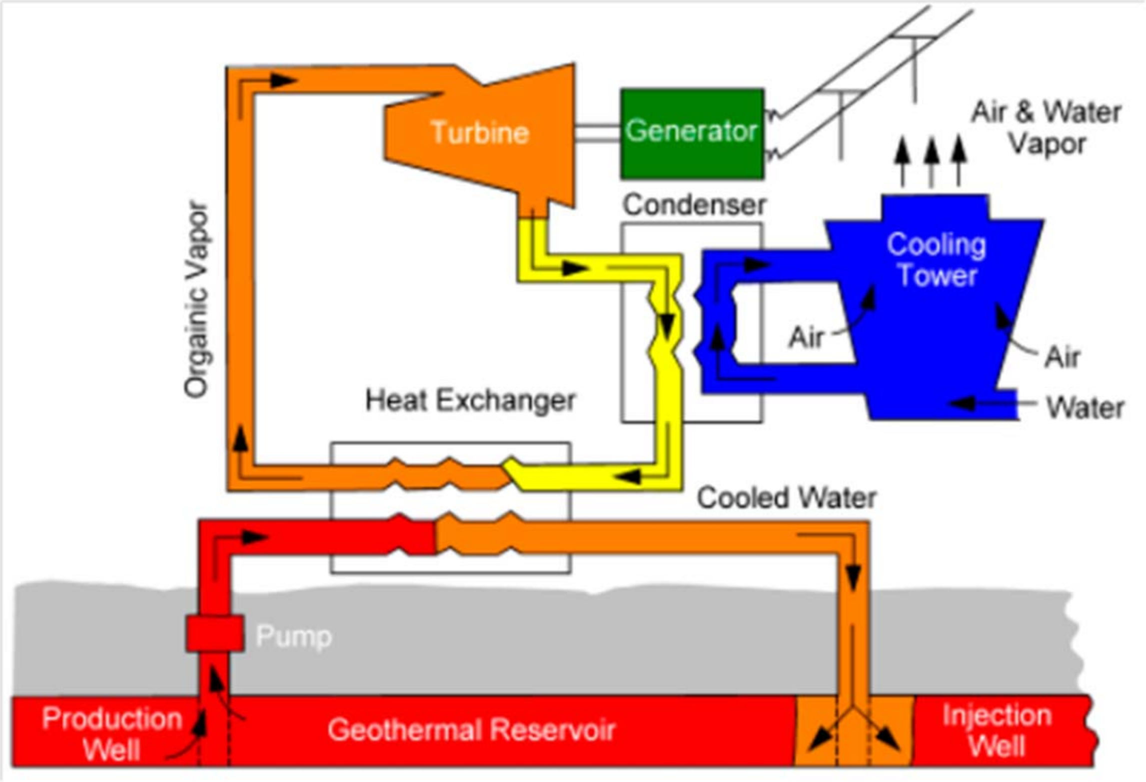
[3] R.Bertani. (2010). Geothermal Power Generation in the World, 2005-2010 update report. Proceedings of the World Geothermal Congress. Bali, Indonesia.

of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350° F [177° C]) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following expansion in the steam turbine, the brine is scrubbed as necessary to remove acid gases and other contaminants, and re-injection wells are employed to return the geothermal brine to the geothermal reservoir.
- Single-Flash or Double-Flash: Flash systems are used in high temperature (i.e., greater than 350° F [177° C]) liquid-dominated geothermal reservoirs. Upon extraction from the geothermal reservoir, the geothermal fluid is a pressurized two-phase mixture of liquid brine and steam. This two-phase mixture is routed to a separator, where the pressure of the mixture is reduced, causing the fluid to flash into steam. This steam is then expanded in steam turbine generator. Double-flash systems flash the separated brine a second time. In double-flash systems, the lower temperature steam may be expanded through a separate steam turbine, or the steam may be introduced into the high-pressure turbine through a second admission port. As in direct steam systems, the spent brine is scrubbed and re-injected into the geothermal reservoir.
- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350° F [177° C]). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine Cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or “hot dry rock”): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

Considering the temperatures associated with geothermal resource areas located in Oregon, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems. Because of the technical and cost uncertainty associated with enhanced geothermal systems, Black & Veatch has selected binary geothermal options for this characterization and has developed performance and cost parameters for a 35 MW-net binary geothermal facility.

In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle, as shown in Figure 4-1. The brine itself does not contact moving parts of the power plant, thus minimizing the potential of equipment fouling (e.g., scaling, corrosion or erosion). Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F [177°C])) or for brines with high dissolved gases or high corrosion or scaling potential.



Source: Colorado Department of Natural Resources

Figure 4-1 Binary Geothermal System

Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower make-up. There is a wide range of candidate working fluids for the closed power cycle. The working fluid of the binary system is generally selected to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid would provide a high utilization efficiency with safe and economical operation.

4.2.2 Technology-Specific Assumptions

Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net geothermal energy facility include the following:

- The geothermal energy facility would employ a binary geothermal system with dry cooling methods (rather than a wet cooling tower) to minimize water requirements.
- The facility will have an average annual capacity factor of 85 percent.
- To extract and re-inject geothermal brine, the facility would utilize 5 supply wells and 5 return wells.
  - Capital costs estimated by Black & Veatch include the cost of well development.
  - Variable O&M costs estimated by Black & Veatch include costs associated with development of 1 new supply well every 5 years. When drilling replacement

wells, it is assumed that 1 out of every 5 supply wells is dry (i.e., does not provide sufficient flow and is unusable), and well replacement costs include costs associated with drilling of dry wells.

- The geothermal project would require 35 acres of land, and this land would be leased for the lifetime of the project. Land lease costs for the geothermal facility are included in the Variable O&M costs estimated by Black & Veatch.

4.3 TECHNICAL AND FINANCIAL PARAMETERS FOR RENEWABLE GENERATION OPTIONS

Technical parameters for renewable energy options considered for PGE are summarized in Table 4-1, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 4-2.

Table 4-1 Technical Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	HEAT RATE VERSUS OUTPUT (BTU/KWH VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIME (HOURS)	START TIME TO FULL LOAD (MINS)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE (PERCENT)	EPC PERIOD (MONTHS)[5]
Biomass Combustion	35	35	85	1.0	13,000	13,350	$y = 4{,}800x^2 - 10{,}800x + 18{,}999$	25	1.75	8.0 / 8.0	180	1.0	3.83	7.5	36
Geothermal -- Binary	35	n/a	85	1.0	n/a	n/a	n/a	50	4.5	0.5 / 0.5	10	0	3.83	6.0	24(6)

Notes:

1. Performance parameters assume ISO conditions (59˚ F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For the biomass combustion option, a heat rate curve is shown as a function of net plant output.
4. While maintaining emissions compliance for the biomass option.
5. The project duration period starts with EPC contractor NTP and ends at the COD. Some excluded activities are permitting and EPC specification development.
6. EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period.

Table 4-2 Financial Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	DESIGN LIFE (YEARS)	EXPENDITURE PATTERN (BY QUARTER)	OVERNIGHT EPC CAPITAL COST ($000, 2015$)	OWNER'S COST ALLOWANCE (PERCENT)[7]	OVERNIGHT TOTAL CAPITAL COST ($000, 2015$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2015$)	FIXED O&M COSTS ($/MW-MONTH)[8]	NONFUEL VARIABLE O&M COST (2015$/MWh)[8]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2015$/MWh)[9]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2015$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2015$/ START)	FUEL STARTUP VARIABLE O&M COSTS (MMBTU-HHV/ START)	DECOMMISSIONING COST ($000, 2015$)[10]
Biomass Combustion	40	Refer to Appendix B	166,000	25	207,500	31,100	140	9.30	n/a	Refer to Note 11	n/a	n/a	29,100
Geothermal -- Binary	30	Refer to Appendix B	229,000	20	274,800	68,700	21	26.75	n/a	Refer to Note 11	n/a	n/a	13,700

Notes (continued from Table 4-1):

7. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
8. Estimates expressed in terms of new and clean condition.
9. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, steam generator, and SCR catalysts, as applicable.
10. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
11. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary, these costs have been included in the relevant O&M costs associated with specific technology options.

5.0 Energy Storage Options

Energy Storage options considered include the following:

- Pumped Storage Hydroelectric (300 MW, 2,400 MWh Closed Loop).
- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 40 MWh Redox Flow Battery).

These energy storage options and their performance and cost characteristics are defined in the following subsections.

5.1 PUMPED STORAGE HYDROELECTRIC

5.1.1 Technology Overview

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand, excess low cost energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or a peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity. The pumping and generating is typically accomplished by a reversible pump turbine / motor generator.

In addition to providing electricity at times of peak power demand, applications for pumped storage hydroelectric projects include:

- Providing transmission system support.
- Energy storage for less dependable renewable resources such as wind and solar energy.

Pumped storage projects may be categorized as either open- loop or closed-loop pumped storage projects. The Federal Energy Regulatory Commission (FERC) defines these classifications as follows:

- Open-loop pumped storage projects are continuously connected to a naturally-flowing water feature.
- Closed-loop pumped storage projects are not continuously connected to a naturally-flowing water feature.

For open-loop pumped storage systems, acquisition of environmental approvals has become increasingly challenging, due to the need to develop a lower reservoir on an active river or existing lake. To mitigate this issue, many recent pumped storage developments have proposed closed-loop systems, which often utilize existing features such as abandoned quarries or underground mines as the lower reservoir of the pumped storage system. This allows the pumped storage project to be developed and operated off-stream, reducing environmental impacts and also reducing costs associated with development of the lower reservoir.

5.1.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for a pumped storage hydroelectric project capable of providing 300 MW of energy output. Relevant assumptions employed in the development of these performance and cost parameters include the following:

- The pumped storage project is assumed to have a maximum output of 300 MW, with a maximum daily discharge period of 8 hours (i.e., maximum energy storage capacity of 2,400 MWh).
- The facility would employ two reversible, variable speed pump turbines, each rated at approximately 1,325 cubic feet per second (cfs). These reversible, variable speed pump turbines are assumed to be located in an aboveground powerhouse near the lower reservoir. Two steel penstocks, each with a diameter of 11 feet, would be located between the inlet/outlet of the upper reservoir and the pump turbine units.
- The lower reservoir of the pumped storage hydroelectric project is either an abandoned quarry, an underground mine or a similar existing feature. Therefore, the project is a closed-loop pumped storage project.
- Upper Reservoir design parameters:
  - Elevation: 2,500 ft above mean sea level (ft msl).
  - Active Water Storage Capacity: 1,750 acre-feet.
  - Active Water Storage Depth: 50 ft.
- Lower Reservoir design parameters:
  - Elevation: 1,000 ft msl.
  - Active Water Storage Capacity: 14,500 acre-feet.
  - Active Water Storage Depth: 50 ft.
- Gross Head design parameters:
  - Average Gross Head: 1,500 ft .
  - Maximum Gross Head, (Generating or Pumping): 1,550 ft.
  - Minimum Gross Head, (Generating or Pumping): 1,450 ft.
- Distance from Upper Reservoir to Lower Reservoir: 1,500 ft (i.e., distance/head ratio of 1.0).
- Fixed O&M costs include the cost of major overhaul of the reversible, variable speed pump turbines in Year 15 of the project's life.

5.2 BATTERY ENERGY STORAGE

5.2.1 Technology Overview

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The batteries of interest for this report are secondary batteries that can be recharged (i.e., the redox reaction can be reversed). The main components of a battery are the positive electrode (cathode), the negative electrode (anode) and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[4]

Battery energy storage systems employ multiple (up to several thousand) batteries and are charged via an external source of electrical energy. The battery energy storage system discharges this stored

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[4] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

energy to provide a specific electrical function. Examples of these functions, as defined by the Energy Storage Association (ESA), are as follows:

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10 to 15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of 1.
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that is capable of responding within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.

The size of a battery energy storage system is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min.
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system).
- Round-trip efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- Discharge duration: how long a battery can be discharged at a given power.
- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes).

Operational parameters associated with battery energy storage technologies include:

- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity. In general, maximum lifetime of battery systems occurs when the SOC is maintained between 10 and 90 percent.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity is degraded to 80 percent of its original capacity.

Battery types employed within battery energy storage systems include lithium-ion (Li-ion), lead-acid and flow batteries. Because Li-ion battery systems appear to be the prevalent battery technology for battery energy storage projects presently under development,[5] this section will focus on two commonly deployed utility scale battery technologies, namely, Li-ion battery and Redox Flow battery technologies.

5.2.1.1 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode. Some examples of cathode and anode combinations are shown in Figure 5-1.

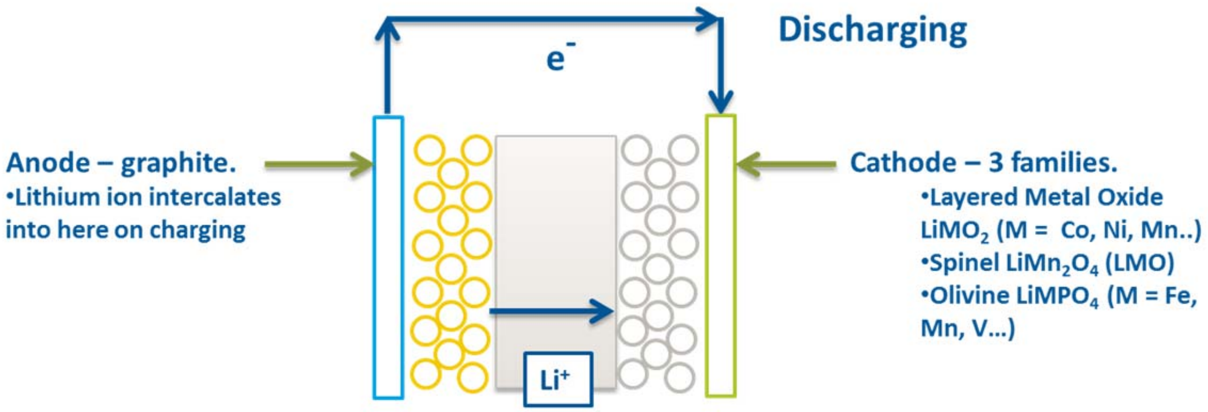

Figure 5-1 Lithium Ion Battery Showing Different Electrode Configurations

The battery cells are integrated to form modules. These modules are then strung together in series/ parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

Lithium ion battery storage systems are typically used for both power and energy applications. One strength of lithium ion batteries is their strong cycle life. For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate good cycle life characteristics. Additionally, lithium ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- Excellent Cycle Life: Lithium ion technologies have superior cycling ability to other battery technologies such as lead acid.
- Fast Response Time: Lithium ion technologies have a fast response time which is typically less than 100 milliseconds.
- High Round Trip Efficiency: Lithium ion energy conversion is efficient and has a 90 percent round trip efficiency (DC-DC).
- Versatility: Lithium ion solutions can provide many relevant operating functions.

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[5] 2020 Strategic Analysis of Energy Storage in California prepared for the California Energy Commission and by the University of California, Berkeley School of Law, University of California, Los Angeles, and the University of California, San Diego. November 2011.

- Commercial Availability: Dozens of strong lithium ion vendors.
- Energy Density: Lithium ion solutions have a high energy density to meet space constraints.

An image of a sample lithium ion BESS can be found in Figure 5-2.

Figure 5-2 Lithium Ion Battery Energy Storage System located at the Black & Veatch Headquarters

Various Li-ion battery systems are installed around the world, including projects in the United States. The 32 MW Laurel Mountain Project in West Virginia, the 32 MWh Tehachapi Project in California, and other projects in Chile and China employ Li-ion systems. PGE also employs a 5 MW Li-Ion system at the Salem Smart Power Center (SSPC) as part of the Pacific Northwest Smart Grid Demonstration. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Li-ion is about 214 MW.[6]

5.2.1.2 Redox Flow Batteries

Vanadium redox flow batteries are another form of electrochemical storage. Vanadium redox flow batteries are the most commercially developed technology of the various flow battery technologies. In this technology, the energy for these systems is stored within a liquid electrolyte stored in tanks. The volume of electrolyte can be scaled to produce the desired energy storage capacity; the power cells (where the reactions happen) can be scaled to produce the desired power output. A diagram of a vanadium redox flow battery can be found on Figure 5-3.

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[6] DOE Energy Storage Database (beta). Sadia National Laboratories. http://www.energystorageexchange.org/

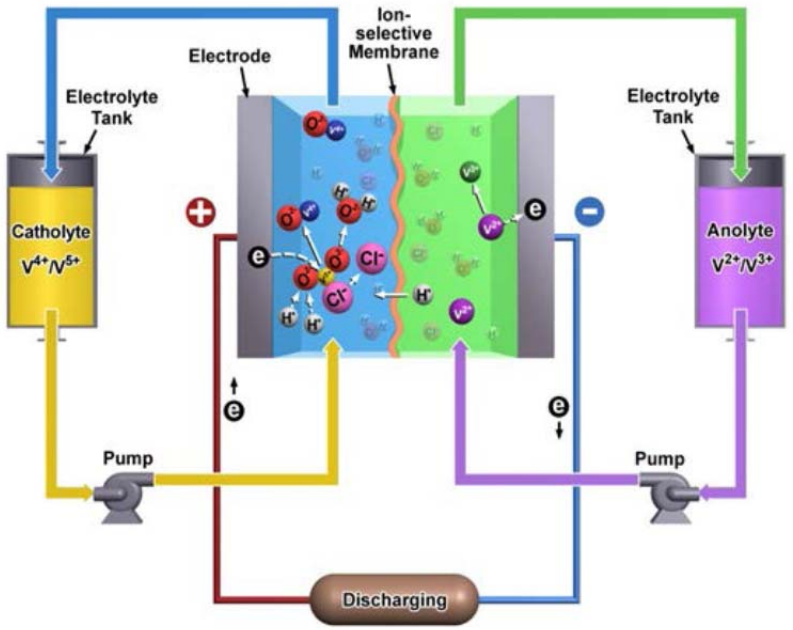

Figure 5-3 **Diagram of Vanadium Redox Flow Battery (Source: DOE/Electric Power Research Institute [EPRI] 2013 Electricity Storage Handbook in Collaboration with National Rural Electric Cooperative Association [NRECA])**

This technology is also integrated with a PCS to form the overall BESS. Vanadium redox batteries are more typically used for energy applications, as they can more effectively be scaled to longer discharge periods than lithium ion batteries. However, one drawback with flow batteries is the space requirements for these systems relative to other battery technologies. The vanadium redox flow batteries require more space for the installation than lithium ion batteries. Vanadium redox BESS can be modular, as shown on Figure 5-4, and containerized systems, as shown on Figure 5-5.

Figure 5-4 **Vanadium Redox Flow Battery (Source: Prudent Energy brochure)**

Figure 5-5 **Containerized Flow Battery (Source: UniEnergy)**

Various Flow battery systems are installed around the world, including projects in the United States. The 600 kW Gills Onions Project in California, the 1 MW Avista Project in Washington, and other projects in Japan and China employ Flow batteries. According to the DOE Energy Storage

Database, the United States installed (or under construction) capacity of Flow battery is about 6 MW.[7]

A summary of representative performance parameters for battery energy storage systems employing Li-ion and Flow batteries is provided in Table 5-1.

5.2.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for 50-MW and 10-MW battery energy storage systems, capable of discharging at their rated power for 2 and 4 hours, respectively. Relevant assumptions employed in the development of these performance and cost parameters include the following:

The battery storage system is assumed to have a 20 year service lifetime. Assuming one (complete) discharge of the battery energy per day, it is anticipated that the battery energy storage modules employed within the system will provide 20 years of operation. No capacity additions (i.e., periodic battery replacement) were included in estimates of either capital costs or O&M costs.
Service contracts for long-term battery maintenance (provided by the OEM) are included in the fixed O&M costs.

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[7] DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org/

Table 5-1 Representative Performance Parameters for Lithium Ion and Redox Flow Energy Storage Systems

PARAMETER	LI-ION	REDOX FLOW
Commercial Availability	Commercial	Commercial
Facility Power Rating, MW	0.005 to 32	0.05 to 5
Module Power Rating, MW	0.005 to 4	0.005 to 0.25
Facility Energy Capacity, MWh	0.005 to 32	0.2 to 10
Module Energy Capacity, MWh	0.1 to 2	0.03 to 0.5
Ramp Rate, MW/min	Note[1]	Note[1]
Response Time[2]	< 100 ms	< 100 ms
Round-Trip Efficiency, percent	75 to 90	65 to 75
Discharge Duration, hours	0.25 to 4	3 to 8
Charge/Discharge Rate, C[3]	C/4 to 4C	C/8 to C/3

Notes:

1. Li-ion and Redox Flow systems are able to ramp up from an idle status to full rated capacity in less than 1 second.
2. Amount of time system takes to reach rated power.
3. Charge/discharge rate is conventionally expressed in terms of “C-rate”. Under this convention, a system with a charge/discharge rate of 2C could be fully charged or discharged in 30 minutes (1/2 hour), while a system with a charge/discharge rate of 6C could be fully charged or discharged in 10 minutes (1/6 hour).

5.3 TECHNICAL AND FINANCIAL PARAMETERS FOR ENERGY STORAGE OPTIONS

Technical parameters for energy storage options considered for PGE are summarized in Table 5-2, while cost and financial parameters for energy storage options considered for PGE are summarized in Table 5-3. Additional parameters specific to energy storage options are shown in Table 5-4.

Table 5-2 Technical Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	HEAT RATE VERSUS OUTPUT (BTU/KWh-HHV VERSUS KW-NET, NEW AND CLEAN)	MINIMUM TURNDOWN CAPACITY (PERCENT)	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIME (HOURS)	START TIME TO FULL LOAD (MINS)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE (PERCENT)	EPC PERIOD (MONTHS)[3]
Pumped Storage Hydro	300	n/a	n/a	2.0	n/a	n/a	n/a	20	100	n/a	2	n/a	2	1.7	60
Battery Storage – Lithium Ion	50	n/a	n/a	0.04(4)	n/a	n/a	n/a	0	Refer to Note 5	n/a	n/a	n/a	2	n/a	12 to 15
Battery Storage – Redox Flow	10	n/a	n/a	0.10(4)	n/a	n/a	n/a	0	Refer to Note 5	n/a	n/a	n/a	2	n/a	12 to 15

Notes:

1. Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. The project duration period starts with EPC contractor NTP and ends at the COD. Some excluded activities are permitting and EPC specification development.
4. For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre.
5. BESS are able to ramp up from an idle status to full rated capacity in less than 1 second.

Table 5-3 Financial Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	DESIGN LIFE (YEARS)	EXPENDITURE PATTERN (BY QUARTER)	OVERNIGHT EPC CAPITAL COST ($000, 2015$)	OWNER'S COST ALLOWANCE (PERCENT)[6]	OVERNIGHT TOTAL CAPITAL COST ($000, 2015$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2015$)	FIXED O&M COSTS ($/MW-MONTH)[7]	NONFUEL VARIABLE O&M COST (2015$/MWh)[7]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2015$/MWh)[8]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2015$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2015$/ START)	FUEL STARTUP VARIABLE O&M COSTS (MMBTU-HHV/ START)	DECOMMISSIONING COST ($000, 2015$)[9]
Pumped Storage Hydro	30	Refer to Appendix B	700,000	25	875,000	218,800	1,000	0.40	n/a	Refer to Note 10	n/a	n/a	8,800
Battery Storage	20	Refer to Appendix B	80,000	12	89,600	11,200	1,250	n/a	n/a	821,250(11)	n/a	n/a	2,200
Battery Storage	20	Refer to Appendix B	38,000	12	42,560	5,300	2,500	n/a	n/a	204,400(11)	n/a	n/a	2,300

Notes (continued from Table 5-2):

6. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
7. Estimates expressed in terms of new and clean condition.
8. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, and batteries.
9. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. For all SSOs except Pumped Storage Hydro, the site would be returned to a brownfield condition at the end of its design life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).
10. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary, these costs have been included in the relevant O&M costs associated with specific technology options.
11. The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

Table 5-4 Additional Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[12]	ENERGY CAPACITY (MWh)	ROUND TRIP EFFICIENCY (PERCENT)
Pumped Storage Hydro	300	2,400(13)	77
Battery Storage – Lithium Ion	50	100	85
Battery Storage – Redox Flow	10	40	75

Notes (continued from Table 5-3):

12. Performance parameters assume ISO conditions (59˚ F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
13. Daily storage based on the 8 hours of discharge per day.

Appendix A. Supply-Side Option Parameters (Full Table)

		Design Basis Parameters						Technical/Performance Parameters												
No.	Supply-Side Option	Option Design Basis	Duty	Net Capacity (MW)(1)	Average Design Life Net Capacity, Including Degradation (MW)	Capacity Factor (%)	Primary Fuel	Land Required (acres/MW)(2)	Net Plant Heat Rate (Btu/kWh-HHV)	Average Design Life Net Plant Heat Rate, Including Degradation (Btu/kWh-HHV)	Heat Rate vs Output (Btu/kWh versus kW-net, New and Clean)	Fuel Consumption versus Output (MMBtu-HHV versus kW-net, New and Clean)(3)	Minimum Turndown Capacity (%)(4)	Ramp Rate (MW/min)	Minimum Run/Down Times (hours)	Start Time to Full Load (mins) (5)	Water Consumption (MGD)	Scheduled Maintenance (weeks/yr) (6)	Equivalent Forced Outage Rate (%)	EPC Period(7) (months)
1	1x0 GE LMS100	Combustion Turbine: GE LMS100 PA Wet IC Emissions Control: SCR, CO catalyst, water injection for NOx control Heat Rejection: Wet Cooling Tower	Peaking	110	105	21%	Natural Gas	0.06	9,031	9,176	See Next Column	$y = 2.25579E-13x^3 - 4.60425E-08x^2 + 1.00877E-02x + 1.40587E+02$	30%	50	0.5 / 0.5	10	0.38	0.07	2.1%	24
2	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO catalyst	Peaking	230	224	21%	Natural Gas	0.04	9,843	9,981	See Next Column	$y = 1.49882E-14x^3 + 1.36515E-08x^2 + 1.41949E-03x + 1.02989E+03$	38%	40	0.5 / 0.5	11	0	0.10	1.5%	24
3	6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO catalyst	Peaking	110	110	13%	Natural Gas	0.06	8,371	8,437	See Next Column	$y = -6.69785E-08x^2 + 9.35009E-03x + 4.57192E+00$	7%	31.8	0.5 / 0.5	10	0.36	0.20	3.2%	24
4	1x1 MHPS M501GAC Fast	Combustion Turbine: MHPS M501GAC Fast Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	395	383	71%	Natural Gas	0.04	6,744	6,926	See Next Column	$y = -1.32139E-13x^3 + 1.24103E-07x^2 - 3.20871E-02x + +4.11935E+03$	58%	54	1.5 / 1.5	Hot: 60 Warm: 100 Cold: 210	1.84	0.84	2.9%	30
5	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	400	387	71%	Natural Gas	0.04	6,370	6,503	See Next Column	$y = -5.85279E-15x^3 + 7.52543E-09x^2 + 2.81340E-03x + 5.92389E+02$	33%	50	1.5 / 1.5	Hot: 60 Warm: 100 Cold: 210	1.86	1.23	2.9%	30
6	2x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	810	784	71%	Natural Gas	0.02	6,351	6,485	See Next Column	$y = -1.26147E-15x^3 + 3.40328E-09x^2 + 3.00625E-03x + 1.14354E+03$	16%	100	1.5 / 1.5	Hot: 60 Warm: 100 Cold: 210	3.71	1.23	2.9%	34
7	Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	35	85%	Wood	1.0	13,000	13,350	$y = 4{,}800x^2 - 10{,}800x + 18{,}999$	n/a	25%	1.75	8.0 / 8.0	180	1.0	3.83	7.5%	36
8	Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	n/a	85%	n/a	1.0	n/a	n/a	n/a	n/a	50%	4.5	0.5 / 0.5	10	0.00	3.83	6.0%	24(16)
9	Pumped Storage Hydro	System: Closed Loop Discharge Duration: 8 hours Upper Reservoir: 2,500 ft. Lower Reservoir: 1,000 ft.	Storage	300	n/a	n/a	n/a	2.0	n/a	n/a	n/a	n/a	20%	100	n/a	2	n/a	2	1.7%	60
10	Battery Storage -- Lithium Ion	Battery: Lithium Ion Discharge Duration: 2 hrs	Storage	50	n/a	n/a	n/a	0.04(14)	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15
11	Battery Storage -- Redux Flow	Battery: Redux Flow Discharge Duration: 4 hrs	Storage	10	n/a	n/a	n/a	0.10(14)	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15

NOTES:

(1) Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity, minus any auxiliary losses.

(2) Typical value; actual value is specific to project, location, and owner's requirements.

(3) For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is Fuel Consumption versus Output (MMBtu-HHV versus kW-net, New and Clean). Heat rate can be further determined by dividing fuel consumption by output.

(4) While maintaining emissions compliance for Options 1 through 7.

(5) Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).

(6) Natural gas fueled option maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance. Renewable option maintenance based on industry norms

(7) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development

(8) Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely

(9) Estimates expressed in terms of new and clean condition.

(10) Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators,steam generator, batteries, and SCR catalysts, as applicable

(11) Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.

(12) Startup fuel consumption for achieving CTG/RICE full load operation.

(13) Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. For all SSOs except Pumped Storage Hydro, the site would be returned to a brownfield condition at the end of its design life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted)

(14) For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre

(15) BESS are able to ramp up from an idle status to full rated capacity in less than 1 second

(16) EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period

(17) Design life for battery energy storage options is consistent with the warranties/guarantees provided by battery OEMs and is consistent with the capacity maintenance costs listed in the Table

(18) Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options

(19) The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

(20) Daily storage based on the 8 hours of discharge per day.

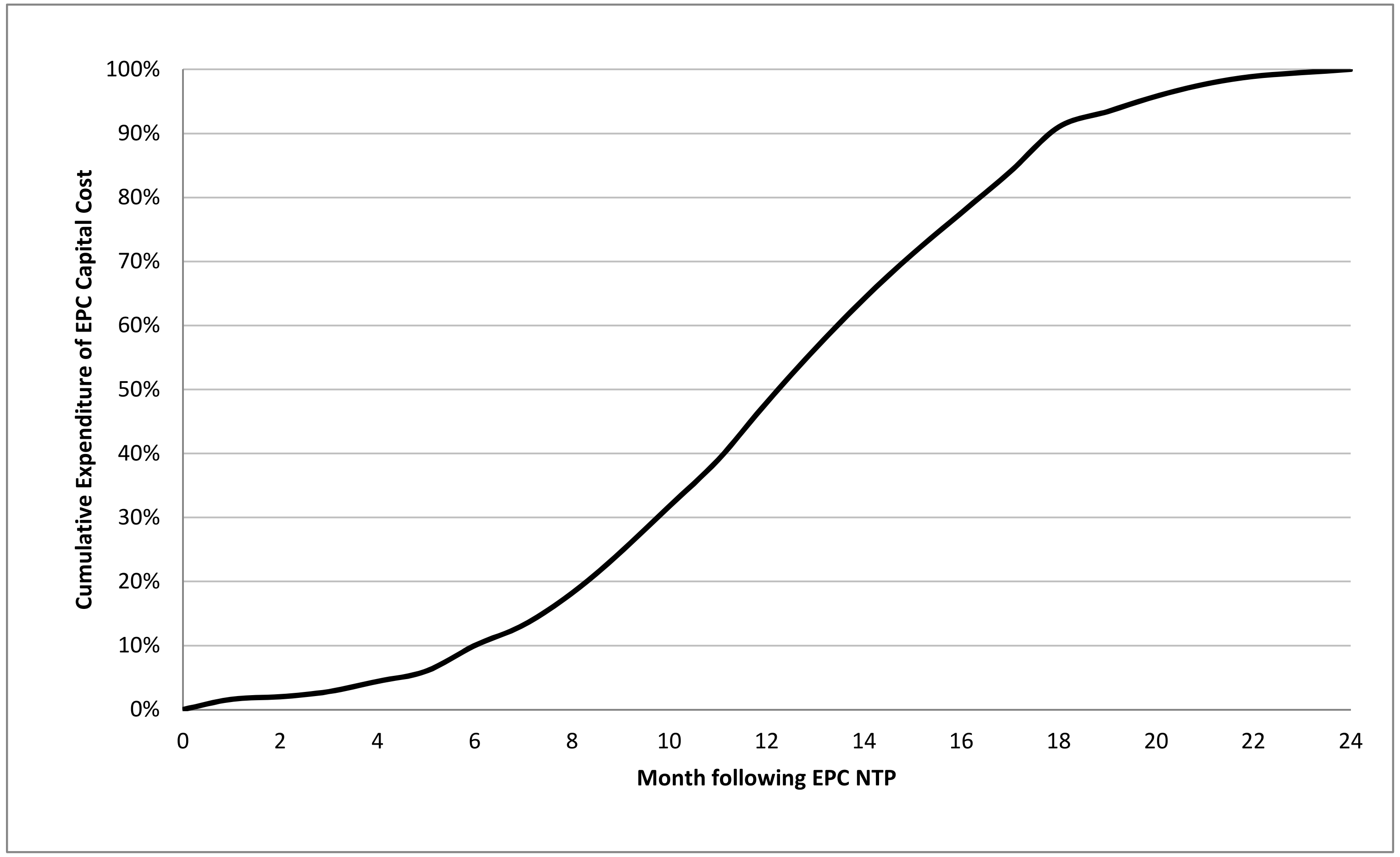
		Financial Parameters													Energy Storage Parameters	
No.	Supply-Side Option	Design Life (years)	Expenditure Pattern (by month/qtr)	Overnight EPC Capital Cost ($000, 2015$)	Owner's Cost Allowance (8) (%)	Overnight Total Capital Cost ($000, 2015$)	Overnight Total Capital Cost Standard Deviation, 1σ ($,000, 2015$)	Fixed O&M Cost (2015$/MW-month)(9)	Nonfuel Variable O&M Cost (2015$/MWh) (9)	Nonfuel Variable Wear and Tear Costs (2015$/MWh)(10)	Capital Additions/ Maintenance Accrual (2015$/yr)	Nonfuel Startup Variable O&M Costs (2015$/start)(11)	Fuel Startup Variable O&M Usage (MMBtu-HHV/start)(12)	Decom-missioning Cost ($000, 2015$)(13)	Energy Capacity (MWh)	Round Trip Efficiency (%)
1	1x0 GE LMS100	30	Refer to Appendix B	99,000	25%	123,800	9,300	267	5.22	3.88	Refer to Note 18	10	66	6,800	n/a	n/a
2	1x0 GE 7F.05	30	Refer to Appendix B	112,000	25%	140,000	10,500	261	9.29	9.03	Refer to Note 18	4	294	7,700	n/a	n/a
3	6x0 Wartsila 18V50SG	30	Refer to Appendix B	128,000	25%	160,000	12,000	280	8.93	5.43	Refer to Note 18	11	72	8,000	n/a	n/a
4	1x1 MHPS M501GAC Fast	30	Refer to Appendix B	342,000	25%	427,500	42,800	744	3.00	1.94	Refer to Note 18	361	850	42,800	n/a	n/a
5	1x1 GE 7HA.01	30	Refer to Appendix B	349,000	25%	436,300	43,600	688	2.60	1.60	Refer to Note 18	369	950	43,600	n/a	n/a
6	2x1 GE 7HA.01	30	Refer to Appendix B	623,000	25%	778,800	77,900	502	2.29	1.55	Refer to Note 18	557	1,900	77,900	n/a	n/a
7	Biomass Combustion	40	Refer to Appendix B	166,000	25%	207,500	31,100	140	9.30	n/a	Refer to Note 18	n/a	n/a	29,100	n/a	n/a
8	Geothermal -- Binary	30	Refer to Appendix B	229,000	20%	274,800	68,700	21	26.75	n/a	Refer to Note 18	n/a	n/a	13,700	n/a	n/a
9	Pumped Storage Hydro	30	Refer to Appendix B	700,000	25%	875,000	218,800	1,000	0.40	n/a	Refer to Note 18	n/a	n/a	8,800	2400(20)	77
10	Battery Storage -- Lithium Ion	20(17)	Refer to Appendix B	80,000	12%	89,600	11,200	1,250	n/a	n/a	821,250(19)	n/a	n/a	2,200	100	85
11	Battery Storage -- Redux Flow	20(17)	Refer to Appendix B	38,000	12%	42,560	5,300	2,500	n/a	n/a	204,400(19)	n/a	n/a	2,300	40	75

Appendix B. SSO Expenditure Patterns

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x0 MW GE LMS100PA

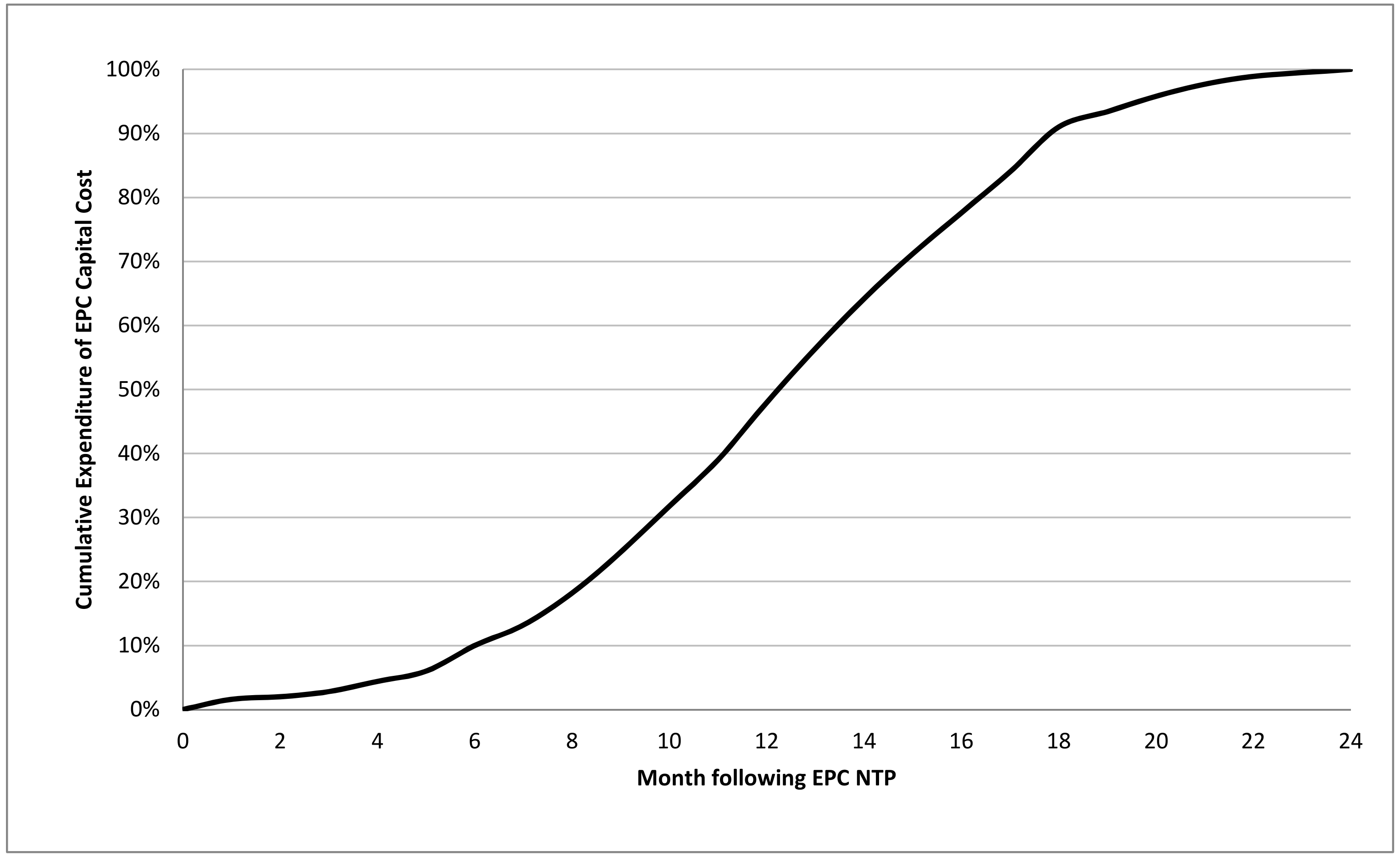
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x0 MW GE 7F.05

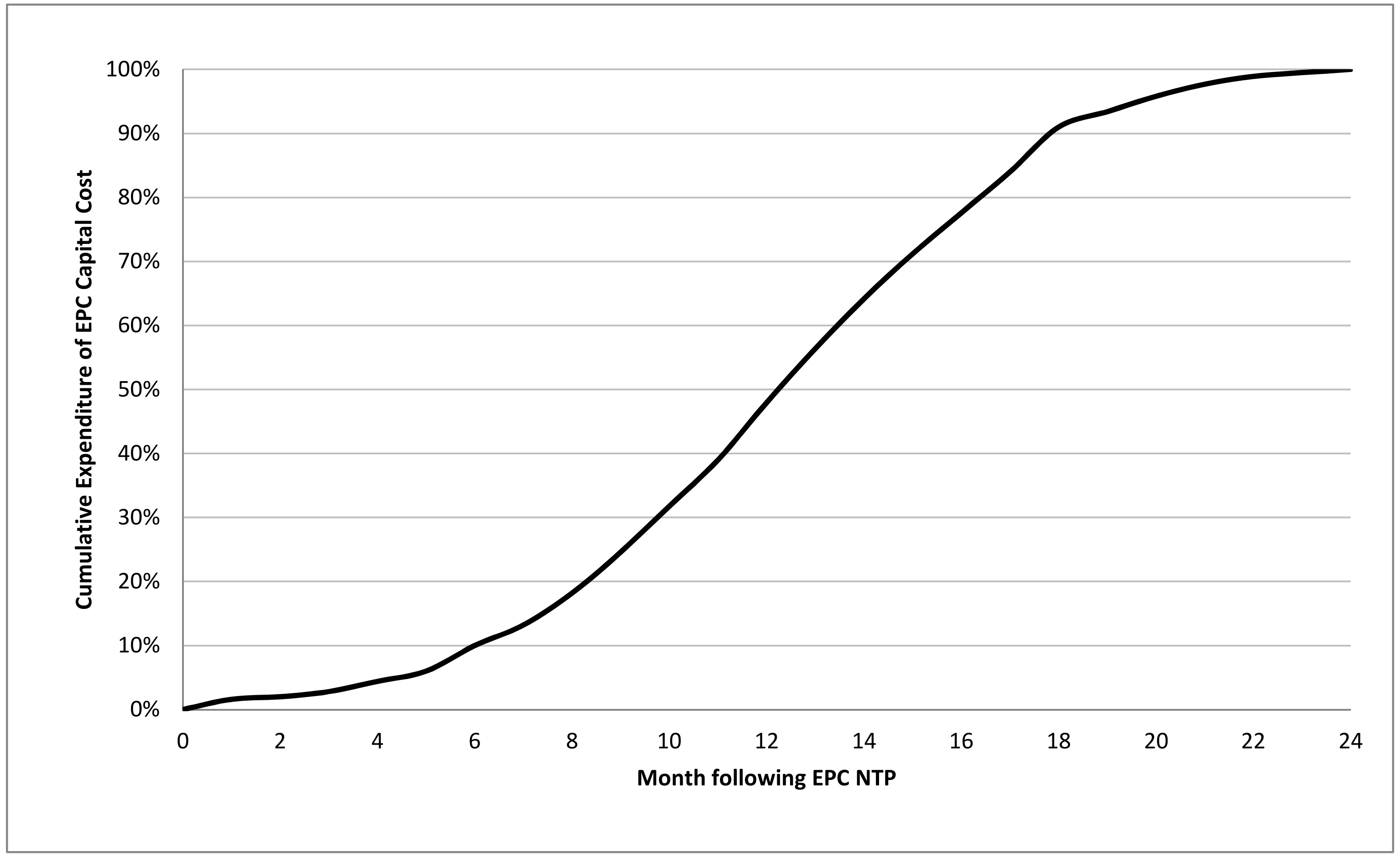
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 6x0 Wartsila 18V50SG

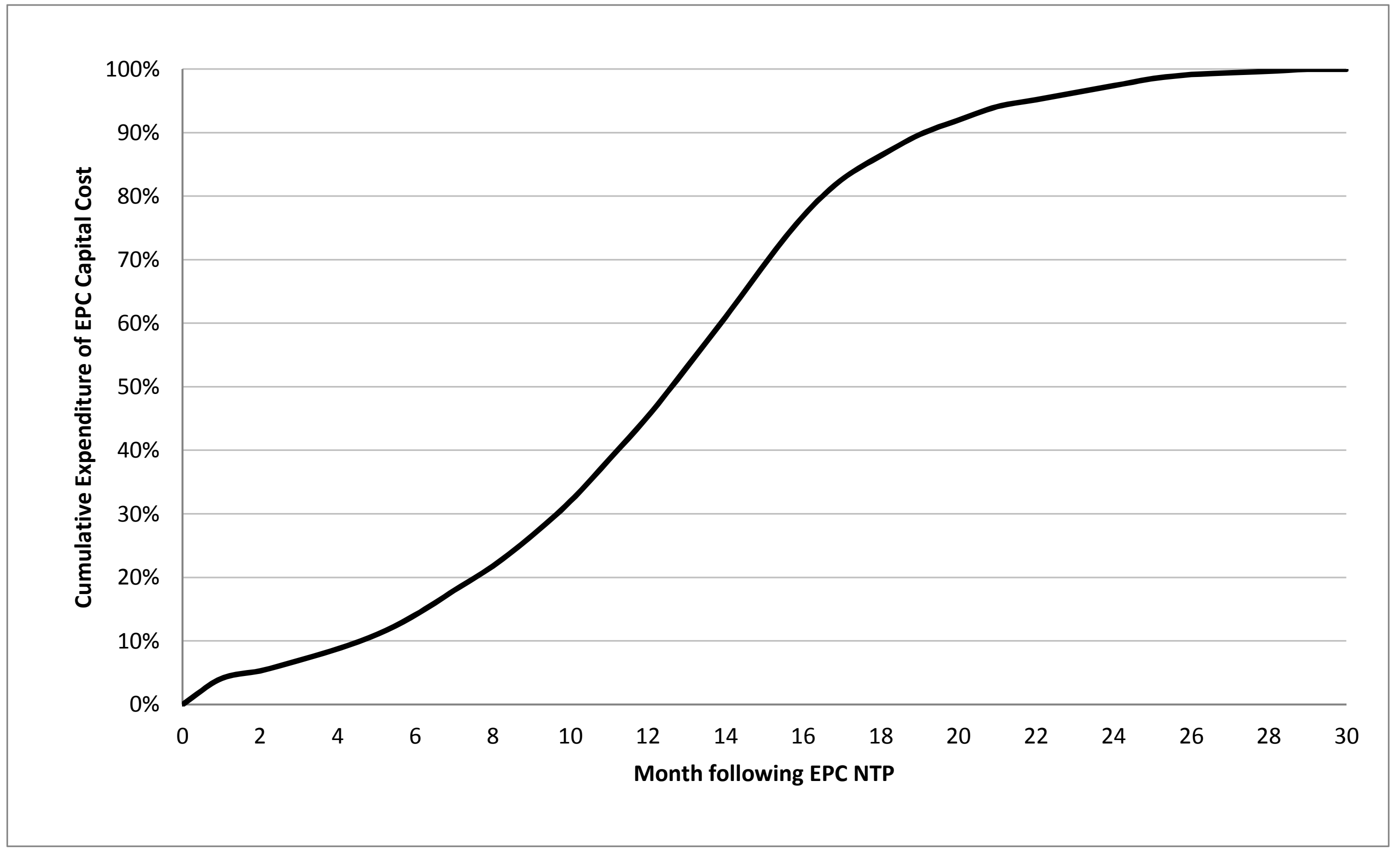
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x1 MHPS M501GAC

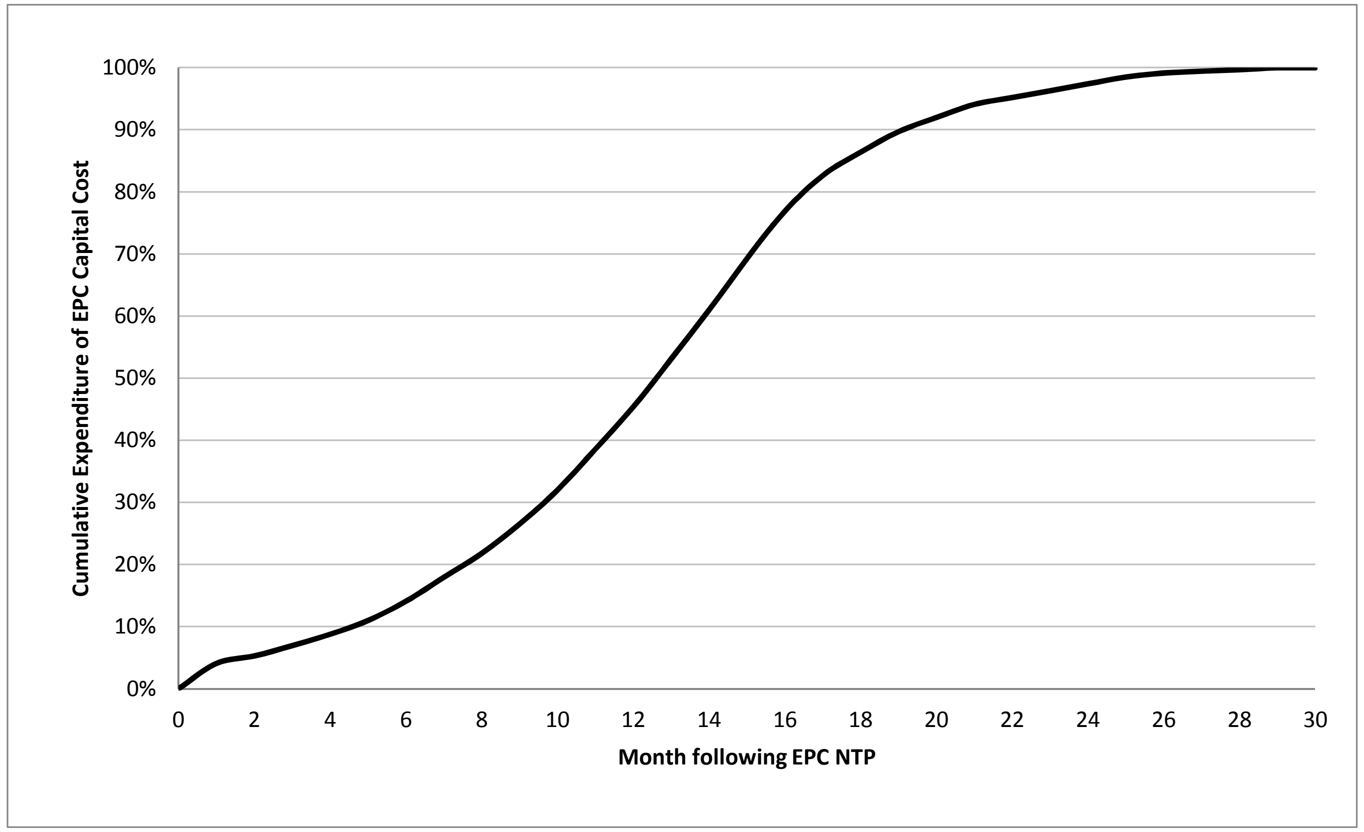
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	4.1%	4.1%
1	2	2	1.2%	5.3%
1	3	3	1.7%	7.0%
1	4	4	1.9%	8.8%
1	5	5	2.2%	11.0%
1	6	6	3.1%	14.1%
1	7	7	3.9%	18.0%
1	8	8	3.9%	21.8%
1	9	9	4.8%	26.6%
1	10	10	5.5%	32.0%
1	11	11	6.6%	38.6%
1	12	12	6.8%	45.4%
2	1	13	7.7%	53.1%
2	2	14	7.9%	61.0%
2	3	15	8.3%	69.3%
2	4	16	7.7%	76.9%
2	5	17	5.8%	82.7%
2	6	18	3.8%	86.4%
2	7	19	3.3%	89.7%
2	8	20	2.3%	92.0%
2	9	21	2.1%	94.1%
2	10	22	1.1%	95.2%
2	11	23	1.1%	96.3%
2	12	24	1.1%	97.4%
3	1	25	1.1%	98.5%
3	2	26	0.7%	99.2%
3	3	27	0.3%	99.4%
3	4	28	0.3%	99.7%
3	5	29	0.3%	100.0%
3	6	30	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 1x1 GE 7HA.01

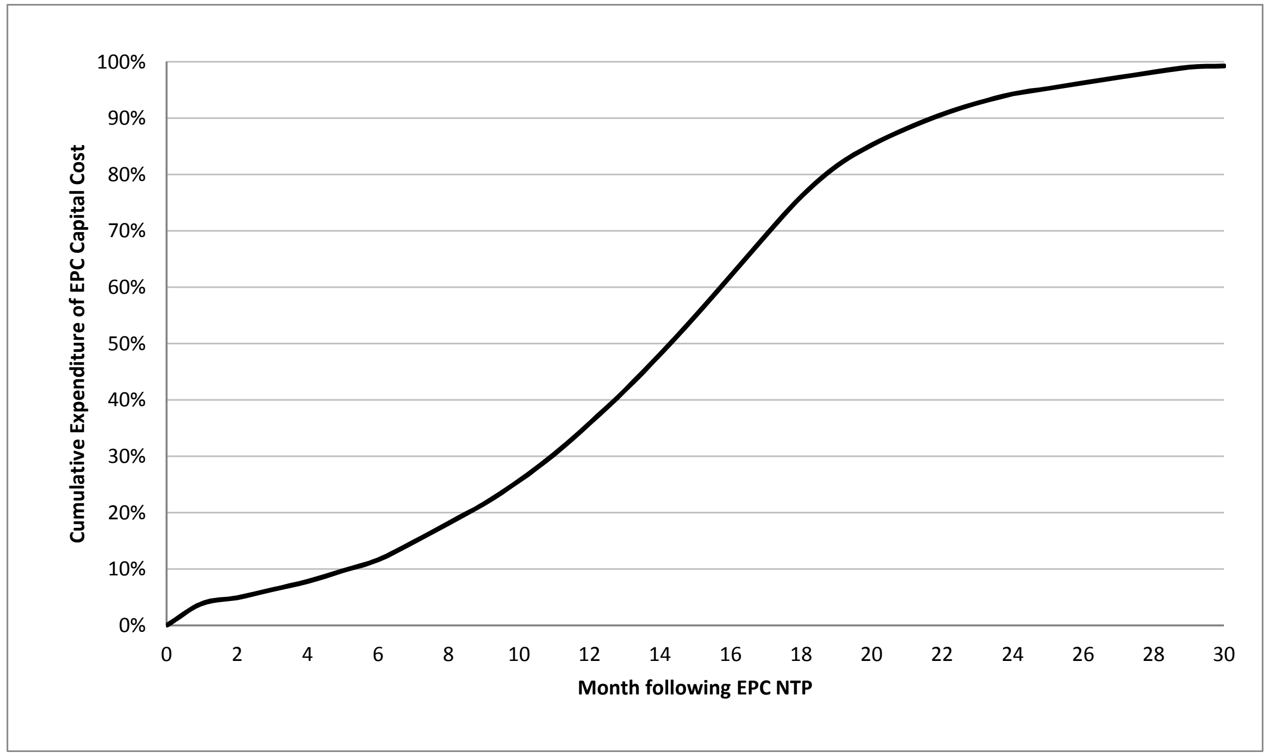
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	4.1%	4.1%
1	2	2	1.2%	5.3%
1	3	3	1.7%	7.0%
1	4	4	1.9%	8.8%
1	5	5	2.2%	11.0%
1	6	6	3.1%	14.1%
1	7	7	3.9%	18.0%
1	8	8	3.9%	21.8%
1	9	9	4.8%	26.6%
1	10	10	5.5%	32.0%
1	11	11	6.6%	38.6%
1	12	12	6.8%	45.4%
2	1	13	7.7%	53.1%
2	2	14	7.9%	61.0%
2	3	15	8.3%	69.3%
2	4	16	7.7%	76.9%
2	5	17	5.8%	82.7%
2	6	18	3.8%	86.4%
2	7	19	3.3%	89.7%
2	8	20	2.3%	92.0%
2	9	21	2.1%	94.1%
2	10	22	1.1%	95.2%
2	11	23	1.1%	96.3%
2	12	24	1.1%	97.4%
3	1	25	1.1%	98.5%
3	2	26	0.7%	99.2%
3	3	27	0.3%	99.4%
3	4	28	0.3%	99.7%
3	5	29	0.3%	100.0%
3	6	30	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 2x1 GE 7HA.01

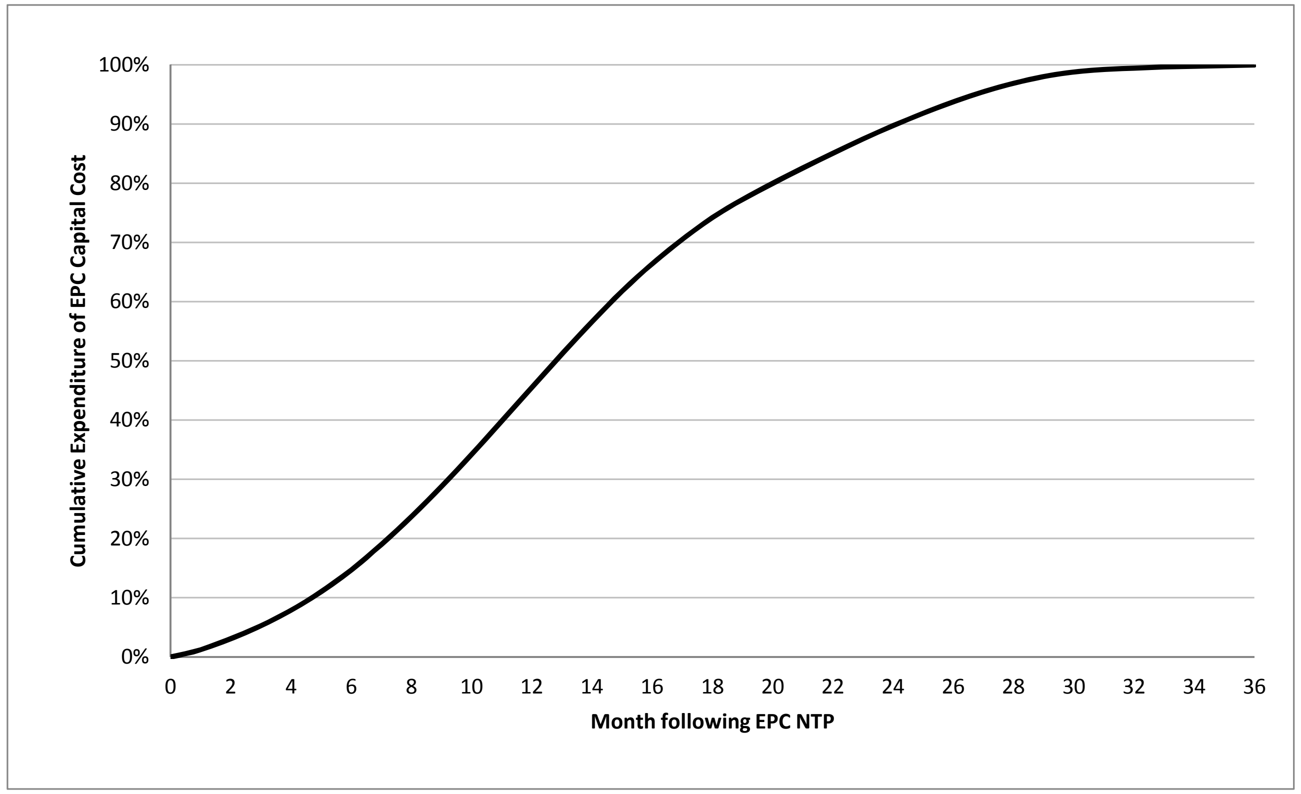
Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	3.9%	3.9%
1	2	2	1.1%	4.9%
1	3	3	1.4%	6.4%
1	4	4	1.5%	7.8%
1	5	5	1.9%	9.7%
1	6	6	1.9%	11.6%
1	7	7	3.1%	14.8%
1	8	8	3.4%	18.2%
1	9	9	3.4%	21.6%
1	10	10	4.1%	25.7%
1	11	11	4.7%	30.4%
1	12	12	5.5%	35.9%
2	1	13	5.8%	41.7%
2	2	14	6.4%	48.1%
2	3	15	6.8%	54.9%
2	4	16	7.1%	62.0%
2	5	17	7.3%	69.3%
2	6	18	6.8%	76.1%
2	7	19	5.4%	81.5%
2	8	20	3.8%	85.2%
2	9	21	2.9%	88.1%
2	10	22	2.6%	90.7%
2	11	23	1.9%	92.6%
2	12	24	1.6%	94.3%
3	1	25	1.0%	95.3%
3	2	26	1.0%	96.2%
3	3	27	1.0%	97.2%
3	4	28	1.0%	98.2%
3	5	29	0.9%	99.0%
3	6	30	0.2%	99.3%
3	7	31	0.2%	99.5%
3	8	32	0.2%	99.8%
3	9	33	0.2%	100.0%
3	10	34	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 35 MW Biomass Combustion (BFB)

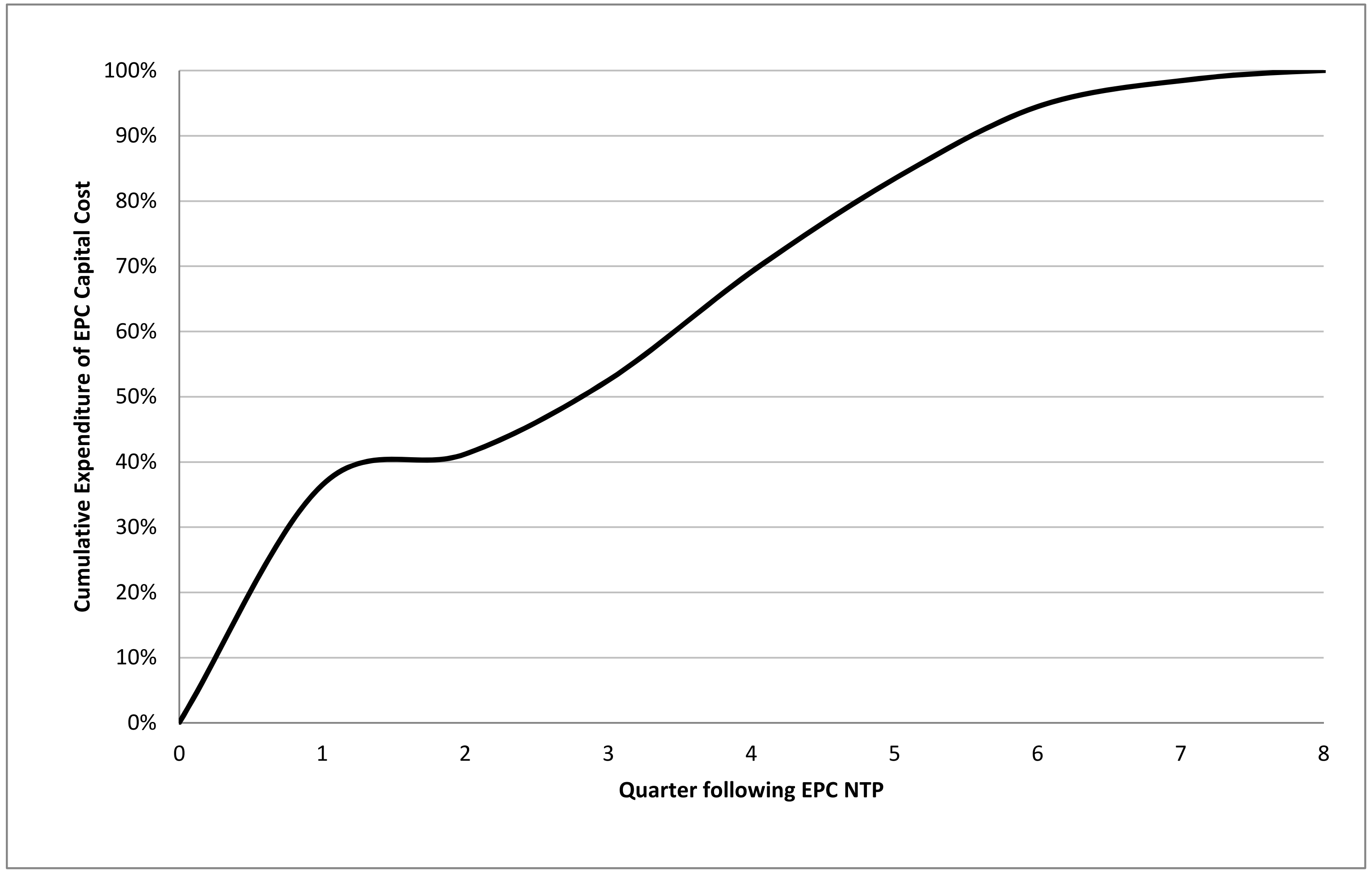
Year	Quarter	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.2%	1.2%
1	2	2	1.9%	3.1%
1	3	3	2.2%	5.3%
1	4	4	2.6%	7.9%
1	5	5	3.2%	11.0%
1	6	6	3.7%	14.7%
1	7	7	4.3%	19.0%
1	8	8	4.7%	23.7%
1	9	9	5.1%	28.8%
1	10	10	5.4%	34.2%
1	11	11	5.6%	39.8%
1	12	12	5.7%	45.5%
2	1	13	5.6%	51.2%
2	2	14	5.5%	56.6%
2	3	15	5.2%	61.8%
2	4	16	4.6%	66.4%
2	5	17	4.1%	70.5%
2	6	18	3.7%	74.2%
2	7	19	3.0%	77.3%
2	8	20	2.7%	80.0%
2	9	21	2.6%	82.6%
2	10	22	2.5%	85.1%
2	11	23	2.4%	87.5%
2	12	24	2.2%	89.7%
3	1	25	2.1%	91.8%
3	2	26	1.9%	93.8%
3	3	27	1.7%	95.5%
3	4	28	1.4%	96.9%
3	5	29	1.1%	98.0%
3	6	30	0.8%	98.8%
3	7	31	0.4%	99.2%
3	8	32	0.2%	99.5%
3	9	33	0.2%	99.6%
3	10	34	0.1%	99.8%
3	11	35	0.1%	99.9%
3	12	36	0.1%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 35 MW Geothermal

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	36.5%	36.5%
1	2	2	4.7%	41.2%
1	3	3	11.3%	52.5%
1	4	4	16.6%	69.1%
2	1	5	14.3%	83.4%
2	2	6	11.1%	94.5%
2	3	7	4.0%	98.5%
2	4	8	1.5%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	0.0%



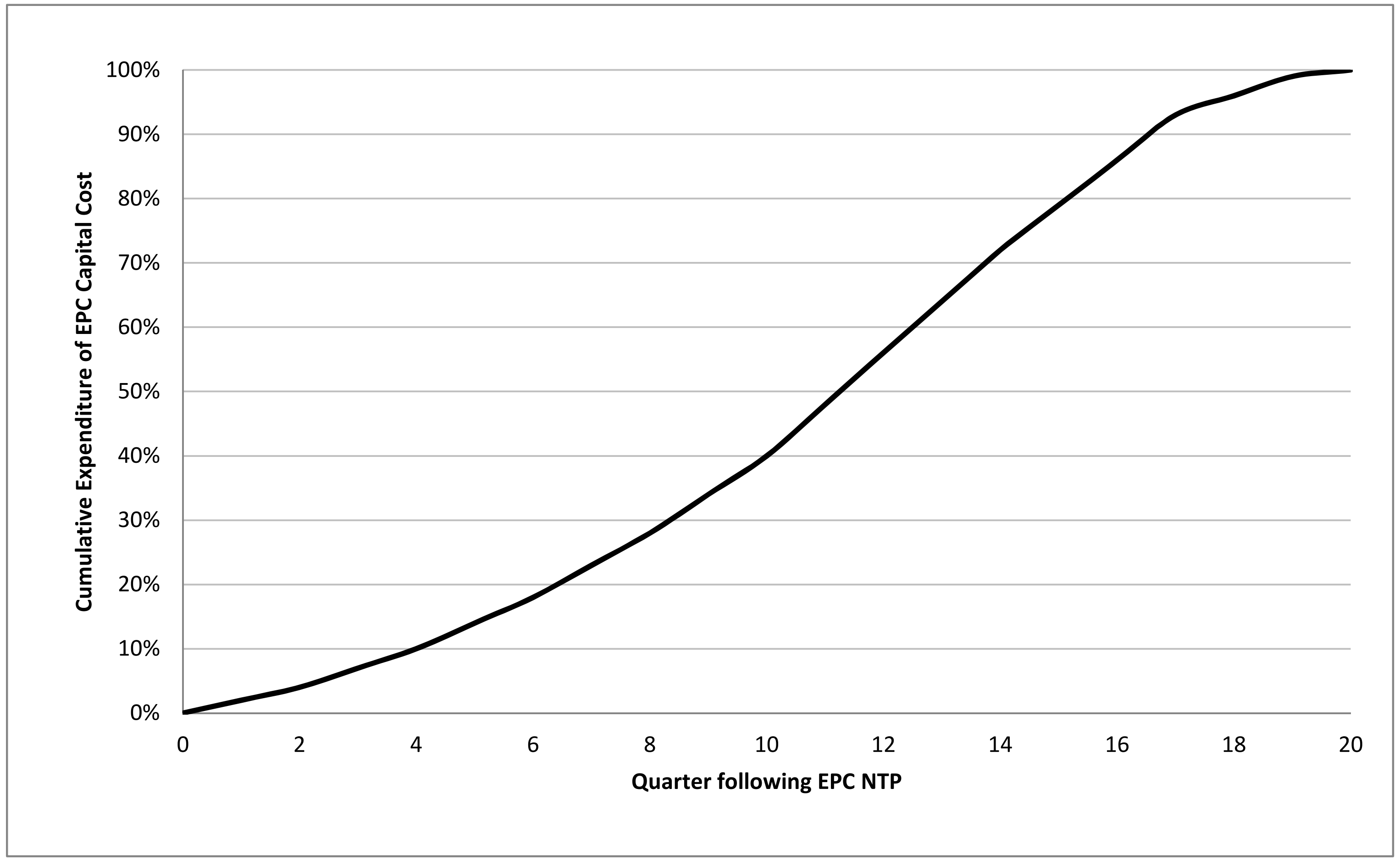
Note:

(1) Geothermal expenditure pattern assumes project development (including well field development) represents roughly one-third of project cost. It is assumed that PGE would buy the project at the beginning of the EPC contract, and all development costs would be re-imbursed to the project developer during Month 1 of the EPC period.

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 300 MW Pumped Storage Hydro

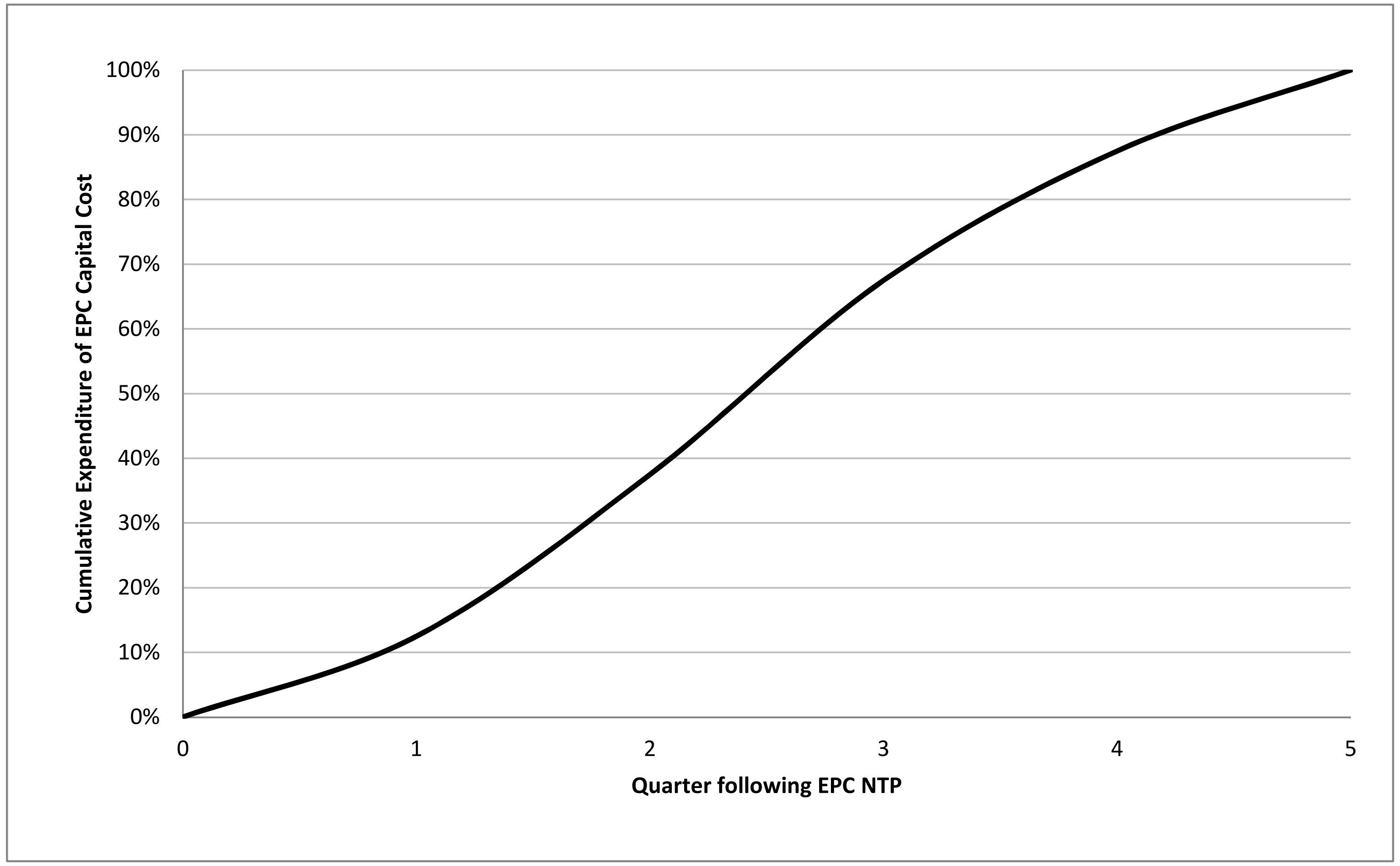
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	2.0%	2.0%
1	2	2	2.0%	4.0%
1	3	3	3.0%	7.0%
1	4	4	3.0%	10.0%
2	1	5	4.0%	14.0%
2	2	6	4.0%	18.0%
2	3	7	5.0%	23.0%
2	4	8	5.0%	28.0%
3	1	9	6.0%	34.0%
3	2	10	6.0%	40.0%
3	3	11	8.0%	48.0%
3	4	12	8.0%	56.0%
4	1	13	8.0%	64.0%
4	2	14	8.0%	72.0%
4	3	15	7.0%	79.0%
4	4	16	7.0%	86.0%
5	1	17	7.0%	93.0%
5	2	18	3.0%	96.0%
5	3	19	3.0%	99.0%
5	4	20	1.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 50 MW Li-Ion Battery Energy Storage

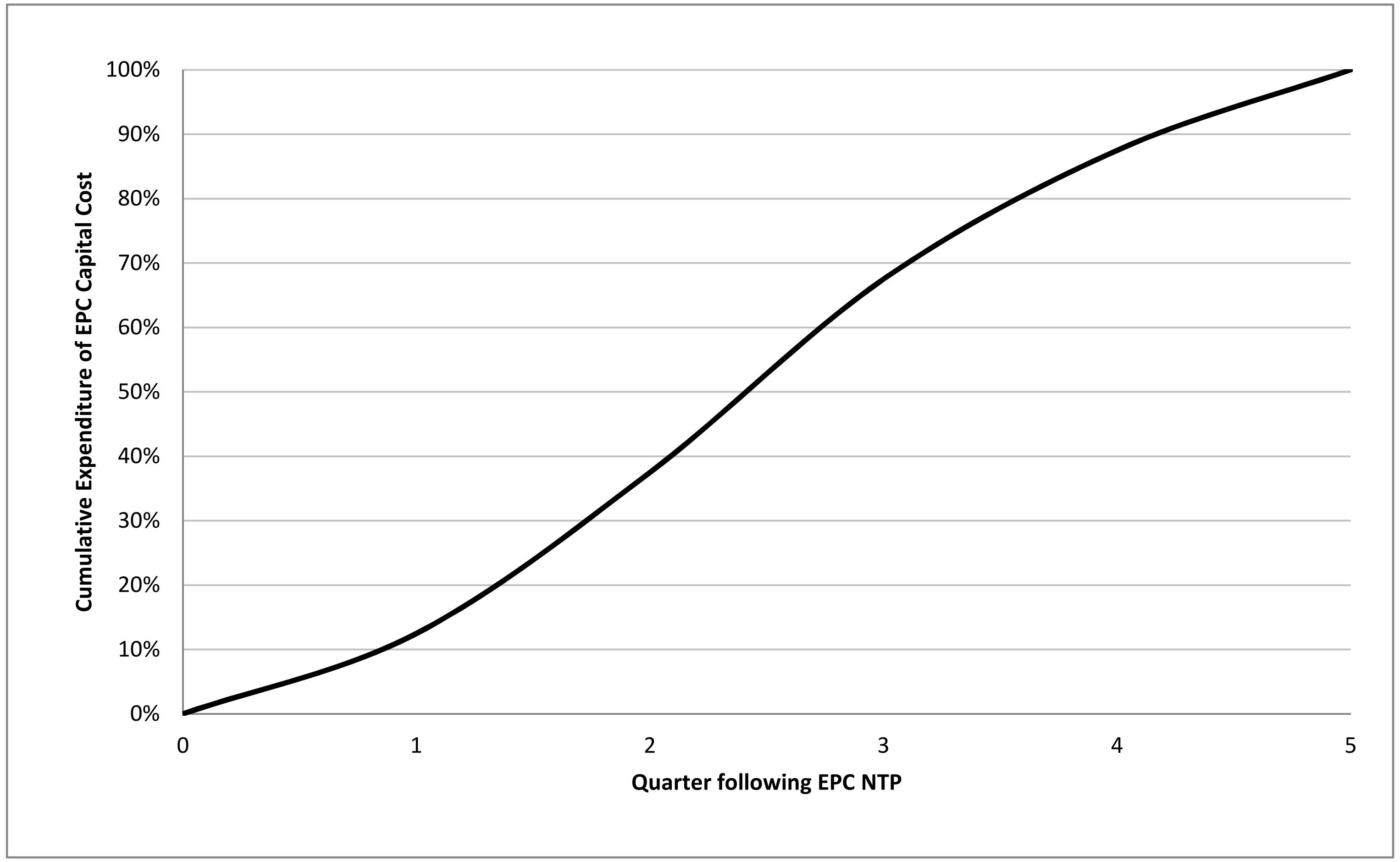
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 10 MW Redox Flow Battery Energy Storage

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Appendix C. Technology Maturity Outlook

Table C-1 **Total Capital Cost Forecast Factors by Technology (Constant Dollar Basis)**

TECHNOLOGY	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pulverized Coal	1.000	1.000	0.992	0.982	0.972	0.961	0.952	0.942	0.934	0.928	0.924	0.920	0.916	0.912	0.907	0.902	0.897	0.891	0.885	0.878	0.872
IGCC	1.000	0.990	0.980	0.962	0.949	0.936	0.923	0.911	0.900	0.890	0.882	0.875	0.870	0.863	0.856	0.849	0.842	0.835	0.827	0.820	0.813
Coal w/ Sequestration	1.000	0.991	0.979	0.962	0.942	0.917	0.904	0.891	0.879	0.869	0.860	0.852	0.846	0.838	0.829	0.821	0.813	0.804	0.795	0.787	0.779
Combustion Turbine	1.000	1.000	0.992	0.982	0.972	0.961	0.952	0.942	0.934	0.928	0.924	0.920	0.916	0.912	0.907	0.902	0.897	0.891	0.885	0.878	0.872
Advanced Comb. Turbine	1.000	0.999	0.984	0.951	0.934	0.917	0.901	0.884	0.870	0.855	0.841	0.828	0.822	0.814	0.804	0.795	0.787	0.779	0.771	0.763	0.758
Combined Cycle	1.000	1.000	0.992	0.982	0.972	0.961	0.952	0.942	0.934	0.928	0.924	0.920	0.916	0.912	0.907	0.902	0.897	0.891	0.885	0.878	0.872
Advanced Comb. Cycle	1.000	0.999	0.987	0.963	0.949	0.935	0.921	0.908	0.896	0.884	0.874	0.865	0.860	0.853	0.845	0.838	0.831	0.824	0.816	0.809	0.804
Adv. CC w/ Sequestration	1.000	0.997	0.983	0.961	0.939	0.909	0.895	0.880	0.867	0.855	0.844	0.835	0.828	0.819	0.809	0.800	0.792	0.783	0.773	0.765	0.757
Fuel Cell	1.000	0.993	0.979	0.962	0.946	0.929	0.913	0.898	0.884	0.871	0.861	0.851	0.841	0.831	0.820	0.809	0.798	0.786	0.774	0.762	0.750
Nuclear	1.000	0.954	0.944	0.922	0.868	0.840	0.829	0.819	0.810	0.802	0.796	0.791	0.785	0.779	0.772	0.765	0.757	0.749	0.740	0.733	0.724
Biomass	1.000	0.991	0.979	0.967	0.956	0.945	0.934	0.923	0.914	0.906	0.901	0.896	0.891	0.885	0.879	0.873	0.867	0.860	0.852	0.845	0.837
Landfill Gas	1.000	1.000	0.992	0.982	0.972	0.961	0.952	0.942	0.934	0.928	0.924	0.920	0.916	0.912	0.907	0.902	0.897	0.891	0.885	0.878	0.872
Wind (Onshore)	1.000	1.000	0.992	0.982	0.972	0.961	0.952	0.942	0.934	0.928	0.924	0.920	0.916	0.912	0.907	0.902	0.897	0.891	0.885	0.878	0.872
Offshore Wind	1.000	0.996	0.985	0.972	0.959	0.945	0.933	0.920	0.909	0.900	0.892	0.886	0.879	0.871	0.864	0.856	0.848	0.839	0.830	0.821	0.811
Solar Thermal	1.000	0.930	0.919	0.906	0.894	0.881	0.869	0.857	0.846	0.837	0.830	0.824	0.817	0.810	0.802	0.794	0.787	0.778	0.769	0.761	0.752
Solar PV	1.000	0.971	0.939	0.927	0.914	0.902	0.889	0.878	0.867	0.858	0.851	0.845	0.839	0.832	0.824	0.817	0.809	0.802	0.796	0.790	0.783
Distributed Gen. Base	1.000	0.998	0.987	0.975	0.963	0.935	0.923	0.912	0.902	0.893	0.887	0.882	0.876	0.869	0.863	0.856	0.849	0.841	0.833	0.825	0.817
Distributed Gen. Peak	1.000	0.998	0.955	0.900	0.848	0.799	0.782	0.759	0.742	0.734	0.728	0.723	0.717	0.711	0.705	0.699	0.692	0.685	0.678	0.671	0.663

National Energy Modeling System (NEMS)

		Design Basis Parameters					Technology Maturity Outlook Factor Adjusted Overnight Capital Cost (2015 Dollars)																				
No.	Option	Option Design Basis	Duty	Net Capacity (MW)$^{(1)}$	Capacity Factor (%)	Primary Fuel	2015 ($000)	2016 ($000)	2017 ($000)	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	2024 ($000)	2025 ($000)	2026 ($000)	2027 ($000)	2028 ($000)	2029 ($000)	2030 ($000)	2031 ($000)	2032 ($000)	2033 ($000)	2034 ($000)	2035 ($000)
1	1x0 GE LMS100	Combustion Turbine: GE LMS100 PA Wet IC Emissions Control: SCR, CO catalyst, water injection for NOx control Heat Rejection: Wet Cooling Tower	Peaking	110	21%	Natural Gas	123,800	123,800	122,800	121,500	120,300	119,000	117,800	116,700	115,700	114,900	114,400	113,900	113,500	112,900	112,300	111,700	111,000	110,300	109,500	108,800	107,900
2	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Peaking	230	21%	Natural Gas	140,000	140,000	138,900	137,400	136,100	134,600	133,200	131,900	130,800	129,900	129,300	128,800	128,300	127,700	127,000	126,300	125,600	124,700	123,800	123,000	122,100
3	6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO catalyst	Peaking	110	13%	Natural Gas	160,000	160,000	158,700	157,100	155,500	153,800	152,300	150,800	149,500	148,500	147,800	147,200	146,600	145,900	145,100	144,300	143,500	142,500	141,500	140,600	139,500
4	1x1 MHPS M501GAC Fast	Combustion Turbine: MHPS M501GAC Fast Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	395	71%	Natural Gas	427,500	427,400	424,000	419,700	415,500	411,000	406,900	402,900	399,400	396,700	394,900	393,300	391,800	389,800	387,700	385,600	383,500	380,900	378,200	375,600	372,700
5	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	400	71%	Natural Gas	436,250	435,900	430,600	420,100	414,100	407,800	401,900	395,900	390,700	385,800	381,300	377,200	375,000	372,100	368,800	365,500	362,600	359,400	356,100	353,100	350,600
6	2x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	810	71%	Natural Gas	778,750	778,100	768,700	750,000	739,300	727,900	717,400	706,800	697,500	688,800	680,600	673,400	669,400	664,200	658,300	652,500	647,300	641,600	635,700	630,300	625,900
7	Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	85%	Wood	207,500	205,700	203,100	200,700	198,400	196,000	193,700	191,500	189,600	188,100	186,900	185,900	184,900	183,700	182,400	181,100	179,900	178,400	176,800	175,300	173,700
8	Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	85%	n/a	274,800	272,400	268,900	265,800	262,800	259,600	256,600	253,700	251,100	249,100	247,500	246,200	244,800	243,300	241,600	239,900	238,200	236,200	234,200	232,200	230,000
9	Pumped Storage Hydro	System: Closed Loop Discharge Duration: 8 hours Upper Reservoir: 2500 ft. Lower Reservoir: 1000 ft.	Storage	300	n/a	n/a	875,000	867,300	856,300	846,400	836,700	826,500	817,000	807,700	799,600	793,000	788,200	783,900	779,600	774,600	769,200	763,700	758,400	752,100	745,600	739,300	732,400
10	Battery Storage -- Lithium Ion	Battery: Lithium Ion Discharge Duration: 2 hrs	Storage	50	n/a	n/a	89,600	83,400	77,800	72,400	67,400	62,900	58,700	54,800	51,200	47,900	45,000	45,000	45,000	45,000	45,000	45,000	44,900	44,800	44,700	44,600	44,500
11	Battery Storage -- Redux Flow	Battery: Redux Flow Discharge Duration: 4 hrs	Storage	10	n/a	n/a	42,560	39,600	36,900	34,400	32,100	29,900	27,900	26,000	24,300	22,800	21,400	21,400	21,400	21,400	21,400	21,300	21,300	21,300	21,200	21,200	21,100

NOTES:

(1) Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation).

(2) Costs are provided in 2015 United States Dollars. No escalation has been applied.

APPENDIX L. Supplemental Findings Across Futures

L.1 NPVRR Summary

Table L-1 summarizes the NPVRR of each portfolio across the 23 futures described in Chapter 10, Modeling Methodology.

TABLE L-1: NPVRR (million 2016$) of each portfolio across each future

Future	RPS Wind 2018 + No Capacity Action	RPS Wind 2018	Efficient Capacity 2021	Wind 2018 Long	Wind 2018	Diverse Wind 2021	Wind 2018 + Solar PV 2021	Geothermal 2021	Boardman Biomass 2021	Wind 2018 + Solar PV 2018	Efficient Capacity 2021 + High EE	Wind 2018 + High EE	Colstrip Wind 2030	Colstrip Wind 2035	Colstrip Efficient Capacity 2030	Colstrip Efficient Capacity 2035	RPS Wind 2020	RPS Wind 2025	RPS Wind 2021	Efficient Capacity 2021 Minimum REC Bank	Efficient Capacity 2021 20% Unbundled RECs
Ref Gas, No CO2, Low Load	23,881	26,345	26,264	26,882	26,463	25,998	26,521	26,580	28,033	26,608	28,639	28,801	26,161	26,126	26,338	26,276	26,509	26,523	26,480	26,432	26,352
Ref Gas, No CO2, Ref. Load	25,593	28,056	27,975	28,594	28,175	27,709	28,233	28,292	29,745	28,320	30,350	30,512	27,873	27,837	28,050	27,988	28,220	28,234	28,192	28,144	28,064
Ref Gas, No CO2, High Load	27,317	29,780	29,699	30,318	29,899	29,433	29,957	30,016	31,469	30,044	32,074	32,236	29,597	29,561	29,774	29,712	29,944	29,958	29,916	29,868	29,788
Ref Gas, Ref. CO2, Low Load	26,460	29,005	28,819	29,376	29,152	28,678	29,206	29,269	30,674	29,292	30,976	31,268	28,713	28,778	28,828	28,894	29,130	29,141	29,107	28,946	28,893
Ref Gas, Ref. CO2, Ref. Load	**28,960**	**31,504**	**31,319**	**31,875**	**31,652**	**31,178**	**31,705**	**31,769**	**33,173**	**31,792**	**33,476**	**33,768**	**31,213**	**31,278**	**31,328**	**31,393**	**31,630**	**31,641**	**31,607**	**31,446**	**31,392**
Ref Gas, Ref. CO2, High Load	31,478	34,022	33,837	34,393	34,169	33,695	34,223	34,287	35,691	34,310	35,994	36,286	33,731	33,796	33,846	33,911	34,148	34,158	34,125	33,964	33,910
Ref Gas, High CO2, Low Load	27,653	29,892	29,591	30,168	30,030	29,569	30,100	30,143	31,534	30,186	31,661	32,063	29,562	29,677	29,599	29,721	29,982	29,989	29,976	29,677	29,635
Ref Gas, High CO2, Ref. Load	30,528	32,767	32,466	33,043	32,905	32,444	32,975	33,018	34,409	33,061	34,536	34,938	32,437	32,552	32,474	32,596	32,857	32,864	32,851	32,552	32,510
Ref Gas, High CO2, High Load	33,424	35,663	35,362	35,939	35,801	35,340	35,871	35,914	37,305	35,957	37,432	37,834	35,332	35,448	35,370	35,492	35,753	35,760	35,747	35,448	35,406
High Gas, No CO2, Low Load	26,884	29,388	29,242	29,544	29,442	28,976	29,530	29,567	30,875	29,616	31,325	31,507	29,313	29,168	29,462	29,280	29,511	29,524	29,467	29,371	29,341
High Gas, No CO2, Ref. Load	29,633	32,137	31,991	32,293	32,191	31,725	32,278	32,315	33,624	32,365	34,073	34,256	32,062	31,916	32,211	32,029	32,260	32,273	32,216	32,120	32,090
High Gas, No CO2, High Load	32,400	34,904	34,758	35,060	34,958	34,492	35,046	35,083	36,391	35,132	36,841	37,023	34,829	34,683	34,978	34,797	35,027	35,040	34,983	34,888	34,857
High Gas, Ref. CO2, Low Load	29,402	31,930	31,838	31,959	32,017	31,544	32,096	32,138	33,427	32,182	33,751	33,906	31,724	31,703	31,927	31,878	32,011	32,019	31,982	31,921	31,911
High Gas, Ref. CO2, Ref. Load	32,767	35,294	35,202	35,323	35,381	34,908	35,460	35,502	36,791	35,546	37,115	37,270	35,088	35,067	35,291	35,242	35,375	35,383	35,346	35,285	35,276
High Gas, Ref. CO2, High Load	36,154	38,682	38,590	38,710	38,768	38,295	38,847	38,890	40,178	38,934	40,502	40,658	38,476	38,455	38,678	38,629	38,762	38,771	38,733	38,672	38,663
High Gas, High CO2, Low Load	30,617	32,817	32,653	32,776	32,899	32,441	32,993	33,016	34,303	33,080	34,485	34,711	32,539	32,604	32,673	32,700	32,874	32,880	32,855	32,707	32,708
High Gas, High CO2, Ref. Load	34,346	36,546	36,381	36,505	36,628	36,170	36,721	36,744	38,032	36,808	38,214	38,440	36,268	36,332	36,402	36,428	36,603	36,609	36,584	36,436	36,436
High Gas, High CO2, High Load	38,101	40,301	40,137	40,260	40,383	39,925	40,477	40,500	41,787	40,564	41,969	42,195	40,024	40,088	40,158	40,184	40,358	40,364	40,339	40,192	40,192
Low hydro	29,693	32,199	31,868	32,506	32,343	31,878	32,397	32,465	33,881	32,485	33,990	34,426	31,928	31,977	31,941	32,018	32,317	32,328	32,294	31,987	31,942
Low wind/solar output	28,975	31,515	31,328	31,886	31,663	31,189	31,746	31,781	33,187	31,835	33,484	33,779	31,223	31,289	31,336	31,402	31,640	31,651	31,617	31,454	31,401
High wind/solar output	28,494	31,028	30,846	31,295	31,151	30,674	31,214	31,288	32,835	31,309	33,053	33,323	30,732	30,800	30,854	30,919	31,190	31,205	31,153	31,014	30,970
Low capital costs	28,345	30,806	30,589	30,979	30,896	30,475	30,990	30,976	32,691	31,087	32,821	33,102	30,537	30,604	30,611	30,684	30,972	30,988	30,930	30,764	30,731
High capital costs	29,574	32,202	32,048	32,771	32,407	31,880	32,421	32,563	33,656	32,498	34,131	34,434	31,888	31,952	32,045	32,102	32,287	32,293	32,284	32,128	32,054

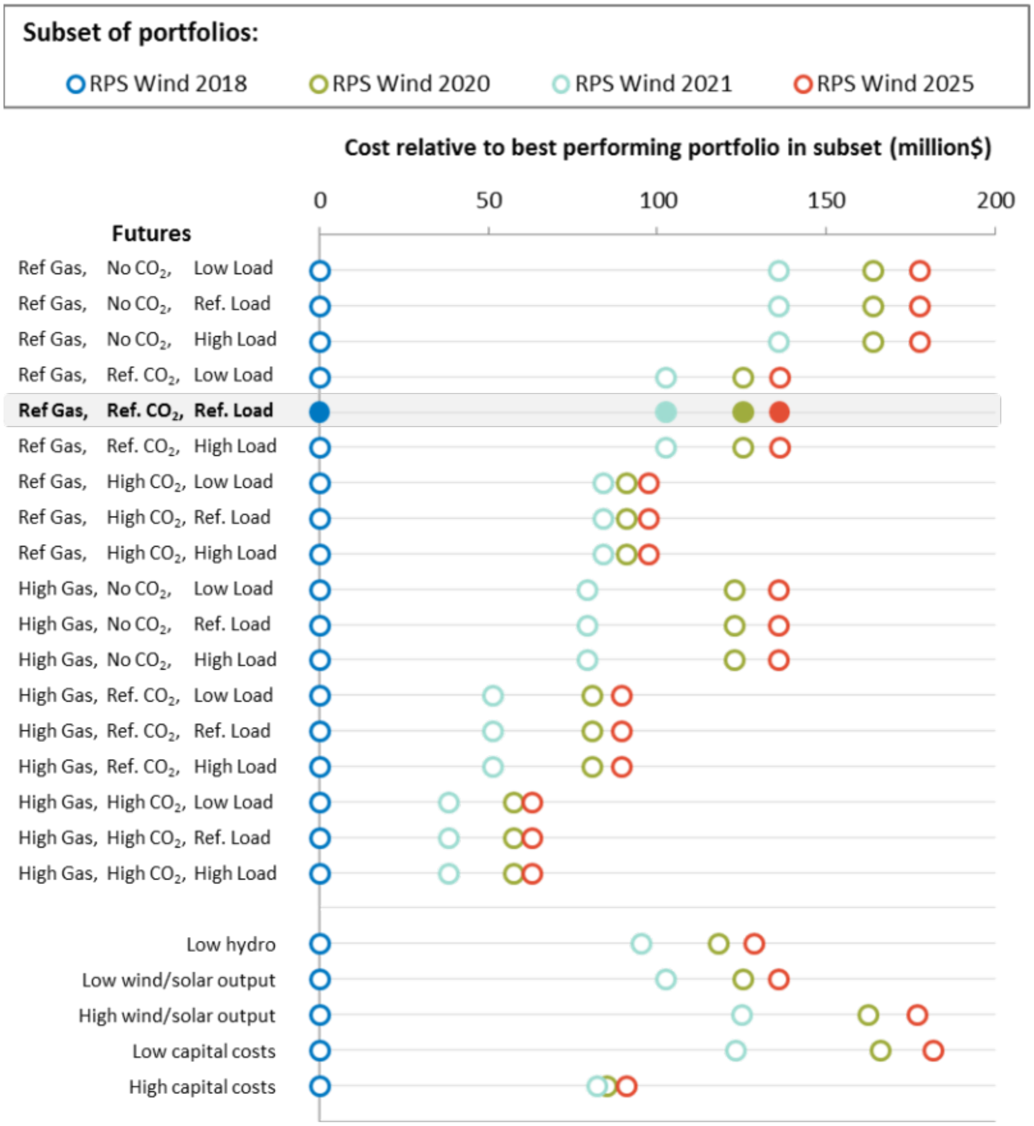
L.2 General Portfolio Conclusions

Chapter 12, Modeling Results, describes several analyses that aimed to answer specific questions by comparing the NPVRR of selected portfolios under reference assumptions. Here, PGE draws additional insights by comparing portfolios across each of the 23 futures.

L.2.1 RPS Timing

In Chapter 12, Modeling Results, PGE demonstrated that under reference assumptions procurement of a wind resource that comes online in 2018 to capture the full value of the PTC results in a lower NPVRR relative to deferring procurement to 2020, 2021, or 2025. A comparison of the NPVRR of the four portfolios designed to investigate the question of RPS timing is shown in Figure L-1 across all futures. Values are shown relative to the lowest cost portfolio in each future in order to highlight portfolio differences within a given future. While the benefits of early action vary across the futures, the finding presented in Chapter 12, Modeling Results, is robust across all futures. The benefits of early procurement are smallest under the High Gas, High CO_2 Price futures and are largest under the Reference Gas, No CO_2 Price futures. The benefits are also larger in futures in which renewable output exceeds expectations and in the case in which capital costs drop faster than anticipated under reference assumptions.

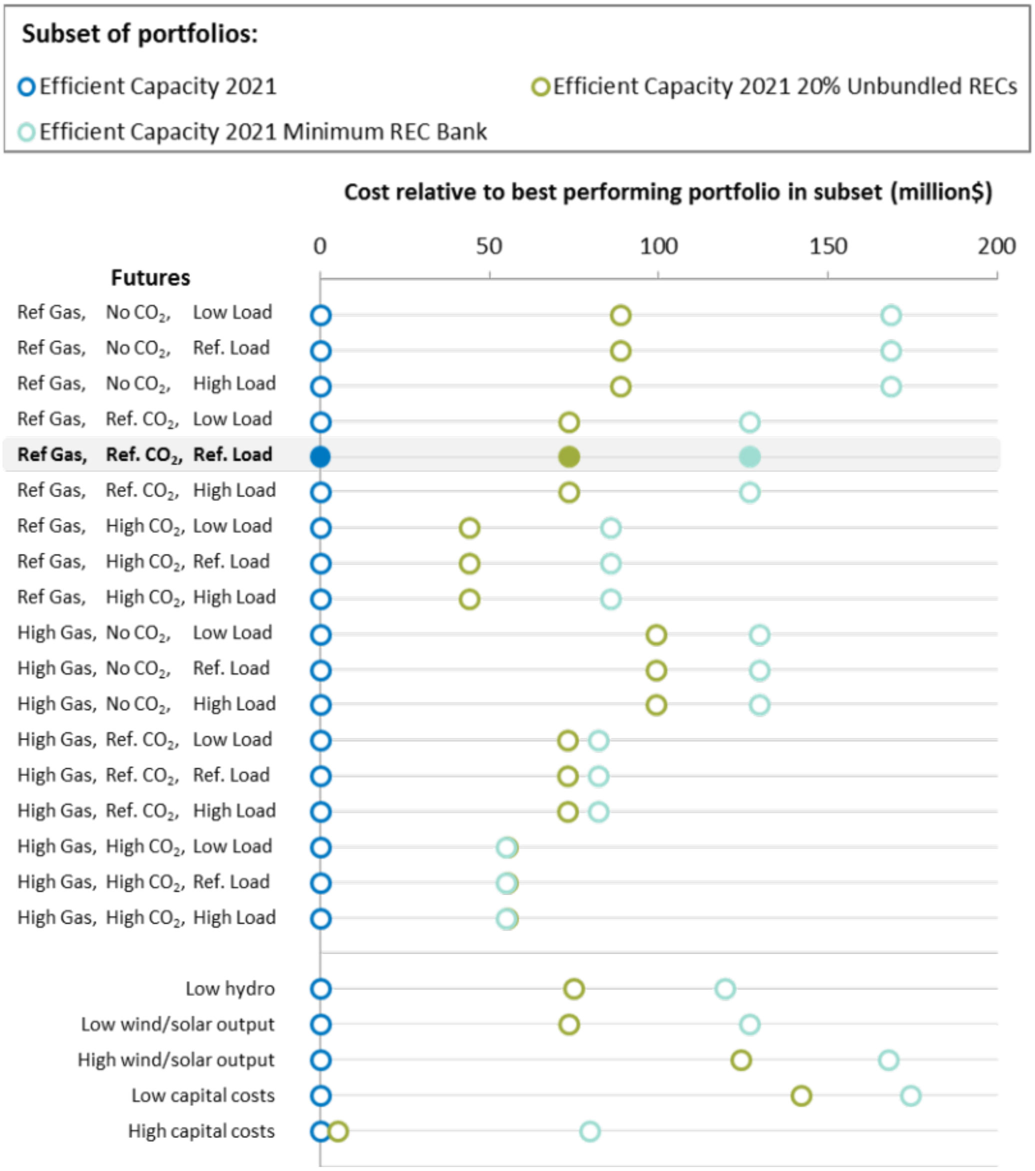
FIGURE L-1: Relative NPVRR of RPS timing portfolios across futures



L.2.2 Banked and Unbundled REC Usage

In Chapter 12, Modeling Results, three portfolios were used to investigate the relative impact of early RPS procurement versus utilization of the REC bank to defer RPS procurement or utilization of unbundled RECs up to the 20% limit. Based on the NPVRR of these portfolios under reference assumptions, it was found that early RPS procurement was lower cost than deferred RPS procurement through either utilization of the REC bank or utilization of unbundled RECs. Figure L-2 illustrates that these conclusions are robust across futures. The benefits of early procurement relative to reliance on the REC bank were largest under the Reference Gas, No CO_2 price futures and were smallest under the High Gas, High CO_2 Price futures. The competitiveness of utilizing unbundled RECs rather than early RPS procurement was best under the High Capital Cost future, but recall that the unbundled RECs were not priced in the analysis. The difference in NPVRR between the *Efficient Capacity 2021 20% Unbundled RECs* portfolio and the *Efficient Capacity 2021 Minimum REC Bank* portfolio was used to calculate a threshold cost above which unbundled REC procurement would not be cost effective relative to reliance on the REC bank. This cost difference is largest under the Reference Gas, No CO_2 Price future and slightly negative (indicating that unbundled RECs should not be bought at any price) under the High Gas, High CO_2 Price future.

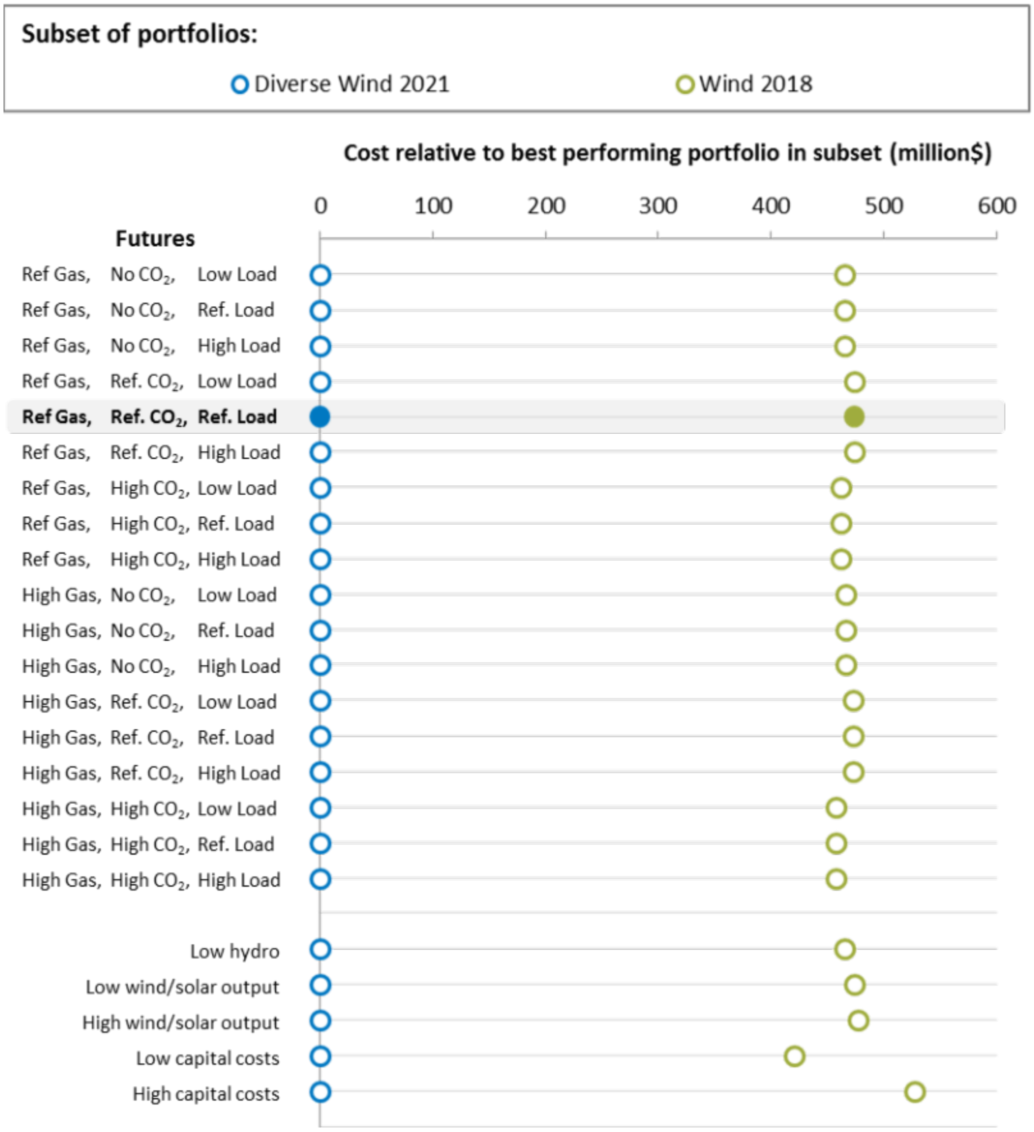
FIGURE L-2: Relative NPVRR of REC strategy portfolios across futures



L.2.3 Diverse Wind Transmission Budget

In Chapter 12, Modeling Results, PGE used the *Wind 2018* and *Diverse Wind 2018* portfolios to identify a budget for transmission to deliver a Montana wind resource to BPA for incorporation into the PGE portfolio. Figure L-3 shows how the NPVRR difference between these two portfolios varies across futures. The relative difference in NPVRR is fairly stable across futures, indicating that the transmission budget identified in Chapter 12, Modeling Results, is not highly sensitive to the uncertainties in future conditions that PGE analyzed. The greatest identified sensitivity is to capital costs – the transmission budget increases under the high capital cost assumption and decreases under the low capital cost assumption, reflecting the increased relative value of higher capacity factor renewables under higher capital cost conditions.

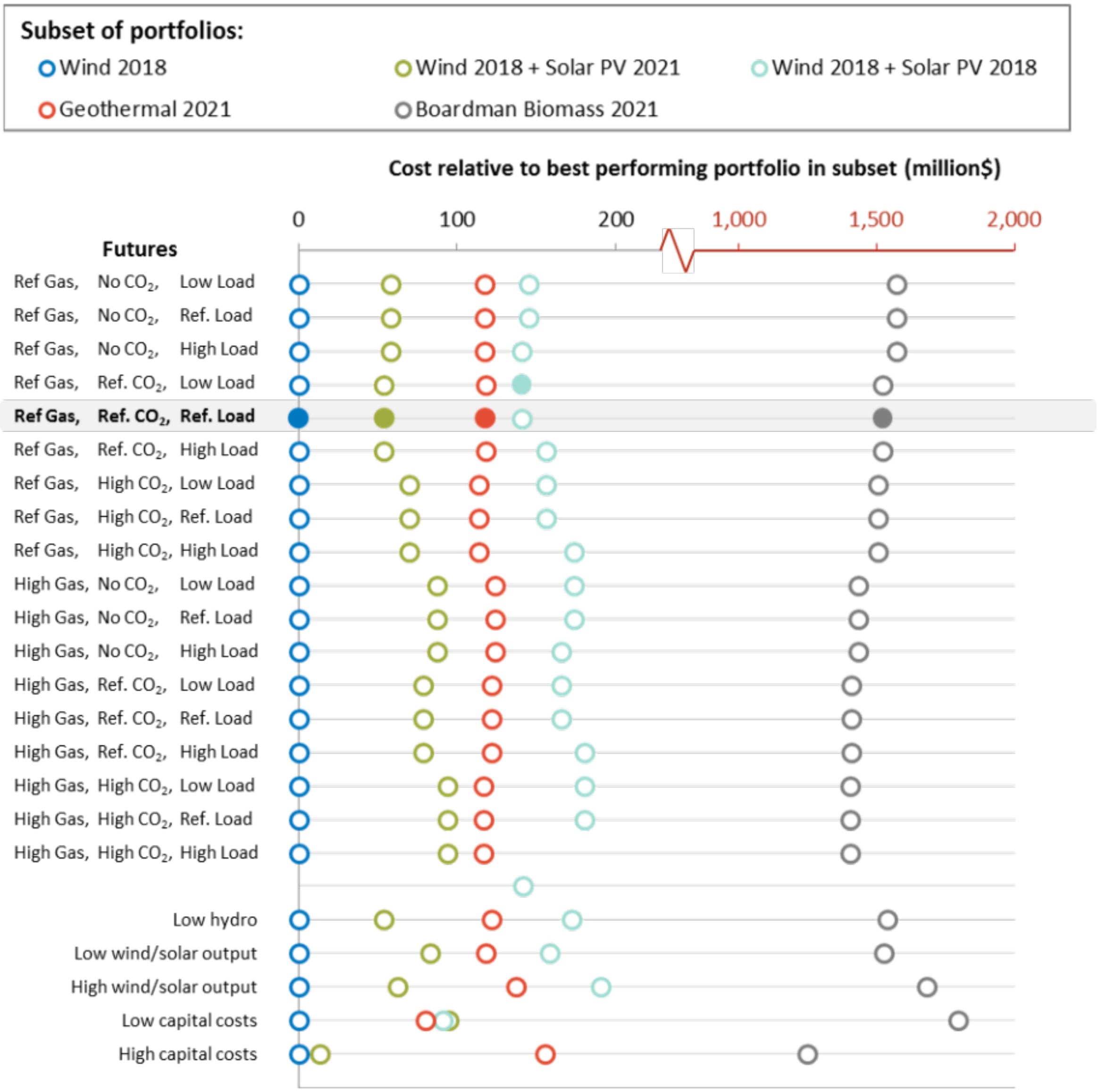
FIGURE L-3: Relative NPVRR of Montana wind transmission budget portfolios across futures



L.2.4 Renewable Resource Economics

Five portfolios were designed to test the relative economics of various renewable resource options in the 2018 and 2021 time frames. In Chapter 12, Modeling Results, the NPVRR of these portfolios under reference conditions suggested that wind was a lower cost renewable option than solar (in 2018 or 2021), geothermal (in 2021), or Boardman biomass (in 2021). Figure L-4 illustrates that this conclusion holds across all futures. Solar in the 2021 time frame was most competitive under reference assumptions and the High Capital Cost future and least competitive under High Gas, High CO_2 price futures and the Low Capital Cost future.

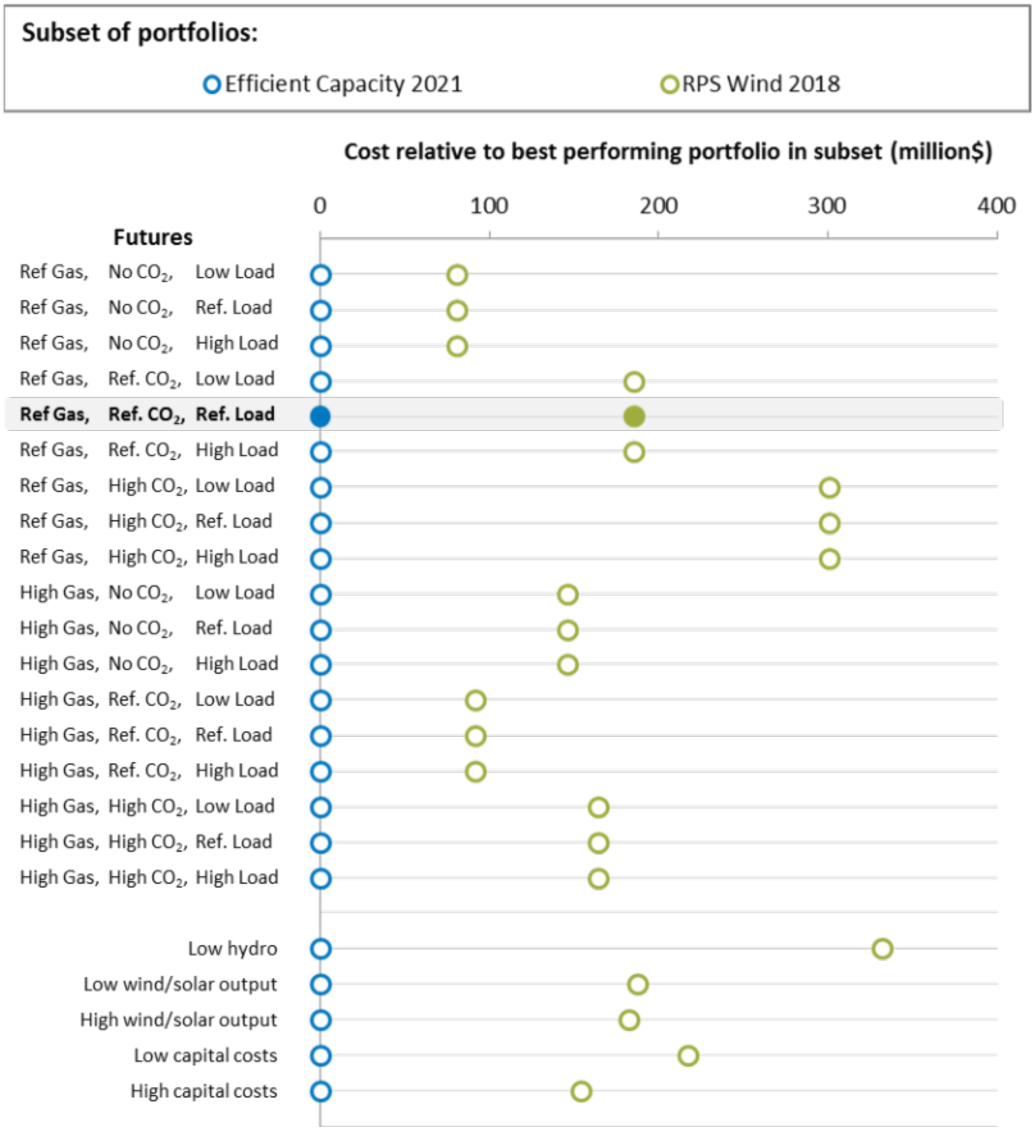
FIGURE L-4: Relative NPVRR of renewable resource option portfolios



L.2.5 Efficient Capacity versus Low Capital Cost Capacity

In Chapter 12, Modeling Results, PGE compared the NPVRR between the *RPS Wind 2018* and *Efficient Capacity 2021* portfolios under reference assumptions to determine whether it was lower cost to procure efficient (i.e., low heat rate) resources to meet capacity shortages that remain after accounting for renewable resource acquisitions or to procure inefficient (i.e., high heat rate) peaking resources to meet the remaining capacity shortage. Figure L-5 shows that across all futures, it is lower cost to procure a highly efficient resource to meet remaining capacity needs. The benefits of highly efficient capacity were largest under Reference Gas, High CO_2 Price futures and the Low Hydro future, highlighting the value of highly efficient dispatchable plants in futures in which low cost energy from hydro and/or coal resources is increasingly scarce. The benefits of the highly efficient capacity were lowest under the Reference Gas, No CO_2 Price future and High Gas, Reference CO_2 Price futures due to the improved competitiveness of coal resources in these futures relative to reference assumptions.

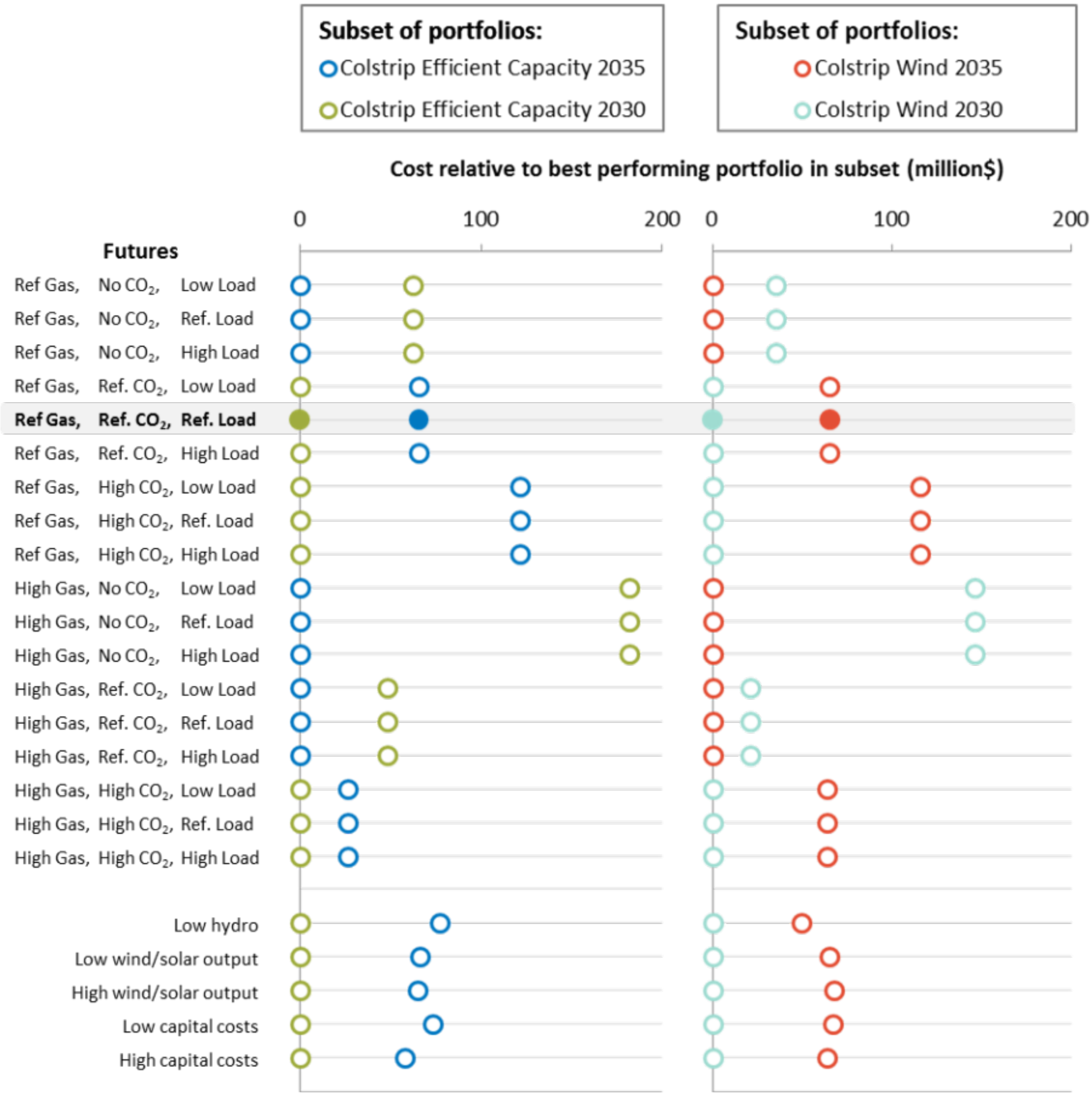
FIGURE L-5: Relative NPVRR of capacity resource option portfolios



L.2.6 Colstrip Timing Economics

As discussed in Chapter 12, Modeling Results, the economics of Colstrip displacement timing are sensitive to gas price and CO_2 price assumptions. This observation is corroborated by Figure L-6, which shows that early displacement of Colstrip is favored under Reference Gas, Reference CO_2 Price futures, Reference Gas, High CO_2 price futures, and High Gas, High CO_2 Price futures regardless of whether the resource is replaced with efficient capacity or wind resources. These observations are consistent with the economic benefits that natural gas resources see relative to coal resources under lower gas prices and higher CO_2 prices. Given the time horizon for PGE's Action Plan in this IRP, PGE does not consider these portfolios in the portfolio scoring process.

FIGURE L-6: Relative NPVRR of Colstrip timing portfolios



L.2.7 Economics of Non-Cost Effective Energy Efficiency

Chapter 12, Modeling Results, includes an analysis of the impact of deploying additional non-cost effective energy efficiency and shows that under reference assumptions, additional energy efficiency was not cost effective in the IRP portfolio analysis framework for both the *Efficient Capacity 2021* portfolio and the *Wind 2018* portfolio. Figure L-7 shows that this conclusion is robust across the futures.

FIGURE L-7: Relative NPVRR of EE portfolios

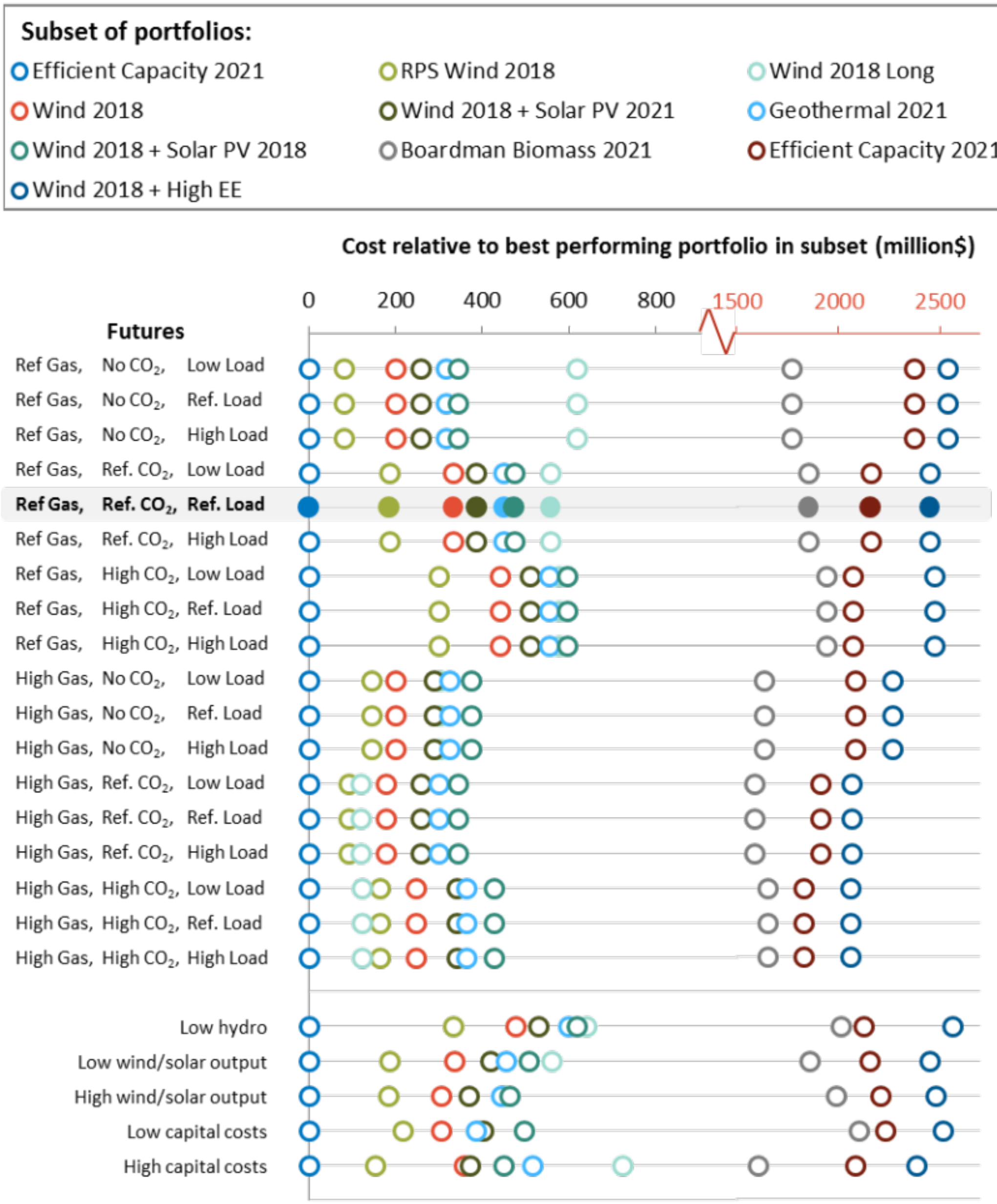
L.3 Comparison Across Portfolios Considered for the Action Plan

The analysis described in Chapter 12, Modeling Results, and further supported in Section L.2, General Portfolio Conclusions, of this appendix helped to narrow the portfolio scoring analysis to the most promising portfolios that were actionable in the time frame of the Action Plan. The scoring of these portfolios is presented in Chapter 12, Modeling Results. This section presents additional insights into the behavior of the actionable portfolios across futures.

L.3.1 Durability Insights

Portfolio scoring includes a durability metric that differentiates between portfolios based on their relative performance in each future – portfolios that consistently perform well across the futures receive a high score and those that consistently perform poorly across the futures receive a low score. This type of metric illuminates differences between portfolios that may not be apparent from a comparison of cost and risk metrics that exclude ordinal information. To provide additional insight into the durability of the portfolios, Figure L-8 shows the performance of each portfolio relative to the lowest cost portfolio in each future. Notably, the *Efficient Capacity 2021* portfolio is lowest cost in every modeled future. The *RPS Wind 2018* portfolio is the second lowest cost portfolio in all futures with the exception of the High Gas, High CO_2 Price futures, in which the *Wind 2018 Long* portfolio is lower cost.

FIGURE L-8: Relative NPVRR of portfolios considered for the Action Plan



L.3.2 Variability Insights

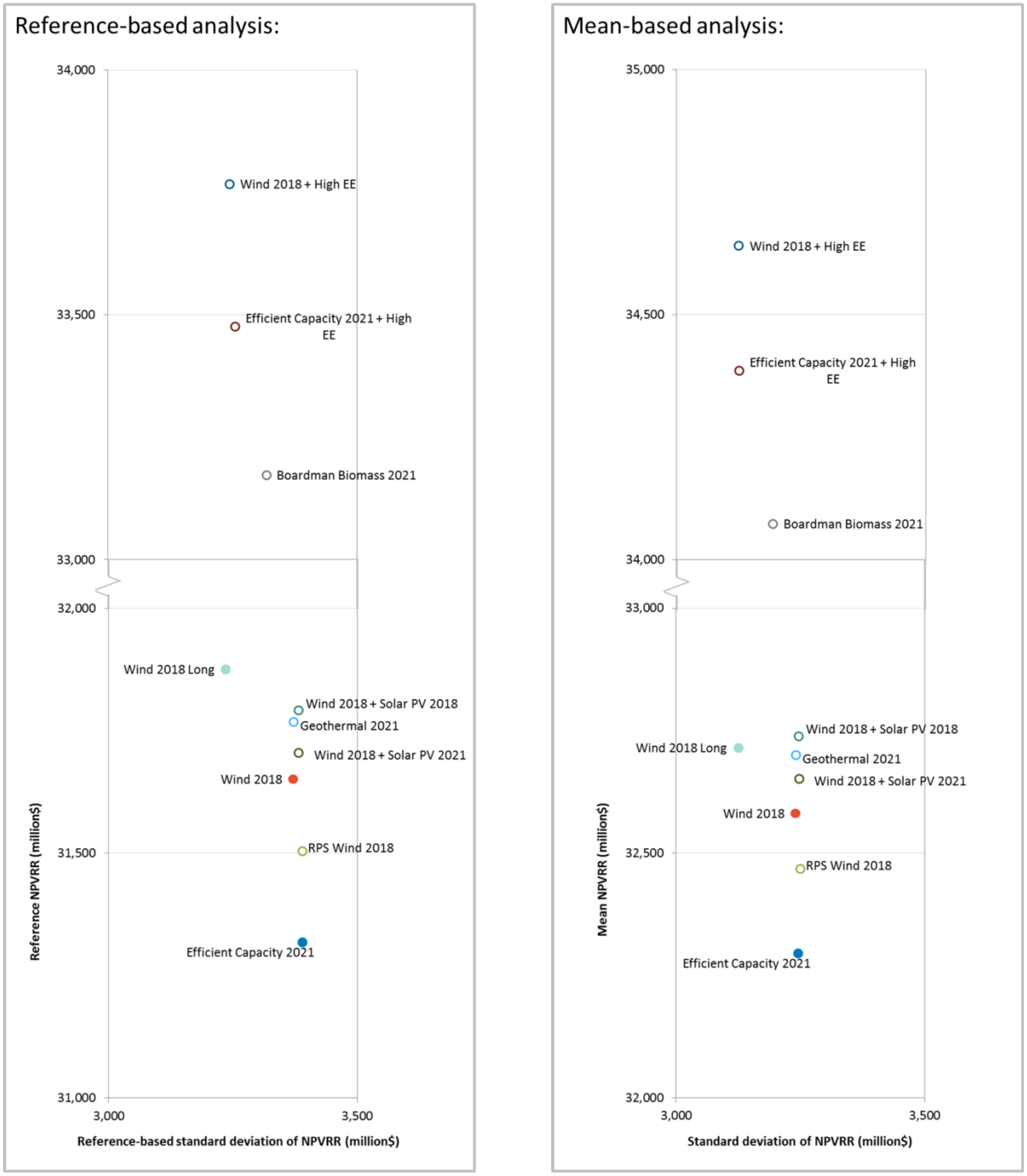
Chapter 11, Scoring Metrics describes the variability and severity metrics, developed over the course of a lengthy public process, suitable for resource planning decisions. PGE's portfolio results can also be reviewed using alternative scoring metrics including classical cost/risk analysis to identify additional insights into the portfolio results. In this appendix, PGE has compared portfolios by the expected portfolio cost and portfolio standard deviation across the futures. PGE includes two alternative approaches to characterizing portfolio expected cost and standard deviation. In the first approach (the Reference-based analysis), the NPVRR under reference assumptions (Reference Gas, Reference CO_2 Price, Reference Load assumptions as well as base case estimates of capital cost and resource performance parameters) is interpreted as the best approximation of the portfolio's expected cost. In the second approach (the mean-based analysis), PGE equally weights the futures to characterize the distribution of potential future conditions. In this approach the standard deviation is calculated relative to the mean across the futures rather than the reference case. The mean-based approach is in response to stakeholder questions regarding alternative approaches to characterizing the expected NPVRR. The resulting cost and risk metrics are summarized in Table L-2 and plotted in Figure L-9.

TABLE L-2: NPVRR statistics across actionable portfolios

Portfolio	Reference NPVRR (million $)	Reference-based standard deviation of NPVRR (million$)	Mean NPVRR (million$)	Standard deviation of NPVRR (million$)
Efficient Capacity 2021	31,319	3,389	32,296	3,245
RPS Wind 2018	31,504	3,390	32,469	3,249
Wind 2018 Long	31,875	3,235	32,716	3,124
Wind 2018	31,652	3,371	32,581	3,240
Wind 2018 + Solar PV 2021	31,705	3,382	32,652	3,247
Geothermal 2021	31,769	3,372	32,701	3,240
Wind 2018 + Solar PV 2018	31,792	3,382	32,740	3,246
Boardman Biomass 2021	33,173	3,318	34,074	3,193
Efficient Capacity 2021 + High EE	33,476	3,255	34,387	3,125
Wind 2018 + High EE	33,768	3,243	34,641	3,124

This framework provides a supplemental approach for determining which portfolios are most promising among the actionable portfolios from the perspective of both cost and risk. Specifically, PGE identified the three portfolios for which no other actionable portfolio performed better with respect to both cost and risk under both the reference-based and mean-based calculations: *Efficient Capacity 2021*, *Wind 2018*, and *Wind 2018 Long*. As shown in Figure L-9, the *RPS Wind 2018* portfolio is also close to meeting this criteria, however the *Efficient Capacity 2021* portfolio has very slightly lower risk in both calculations.

FIGURE L-9: Supplemental cost/risk analysis for actionable portfolios



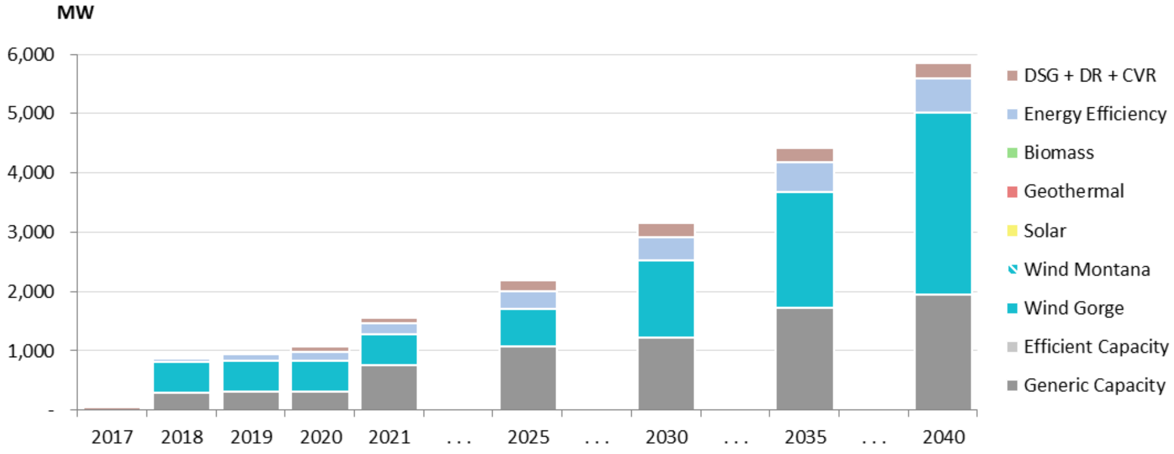
L.4 Comparison Across Portfolios Considered for the Renewable Portfolio Implementation Plan

PGE also used the portfolio analysis in this IRP to select two renewable portfolios as the basis of the Renewable Portfolio Implementation Plan (RPIP). In addition to the RPS timing portfolios, PGE tested a variation on the *RPS Wind 2018* portfolio, *RPS Wind 2018 + Staged RPS 2030*. The renewable additions across these two portfolios are the same through 2025, but *RPS Wind 2018 + Staged RPS 2030* includes equally-sized additions in 2030 and 2035 in order to maintain REC bank levels prior to the 2040 addition. In the *RPS Wind 2018* portfolio, the early RPS procurement in 2018 allows PGE to reduce costs through the PTC and also to make use of banked RECs to defer RPS procurement from 2030 to 2035 to realize further cost reductions. In the *RPS Wind 2018 + Staged RPS 2030* portfolio, PGE tests the economic impact if these deferral savings cannot be realized due potentially to a limited ability to procure the large 2035 addition in full. The *RPS Wind 2018 + Staged RPS 2030* portfolio is summarized in Table L-3 and Figure L-10.

TABLE L-3: *RPS Wind 2018 + Staged RPS 2030* cumulative resource additions, capacity (MW)

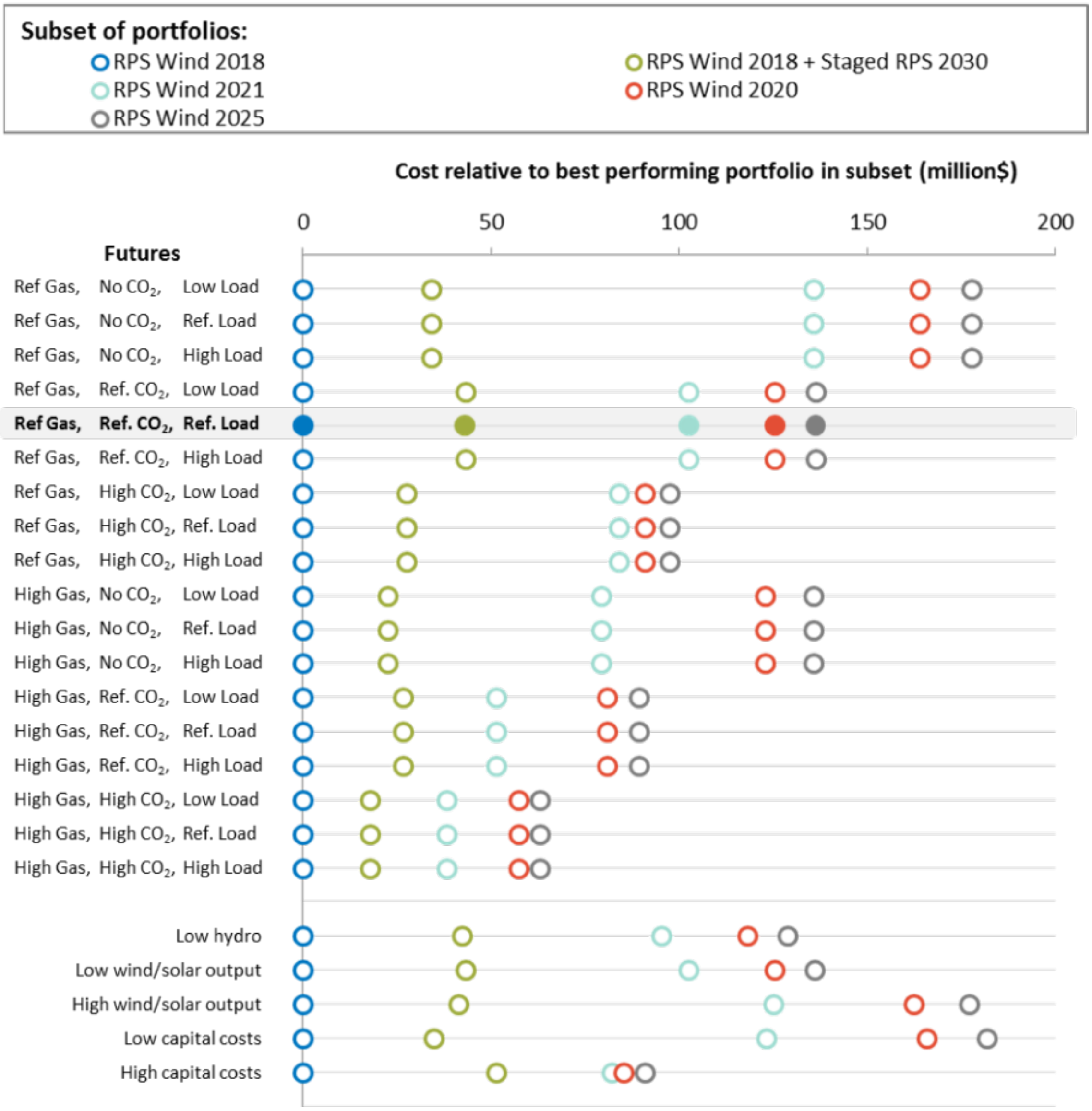
Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
Wind Gorge	-	515	515	515	515		628		1,298		1,968		3,074
Wind Montana	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	760		1,072		1,220		1,713		1,940

FIGURE L-10: *RPS Wind 2018 + Staged RPS 2030* cumulative resource additions, capacity (MW)



As shown in Figure L-11, the *RPS Wind 2018* and *RPS Wind 2018 + Staged RPS 2030* portfolios consistently outperform the other RPS timing portfolios across all futures. This finding indicates that even if the full deferral value afforded by the 2018 early procurement cannot be realized, the value of the PTC is still large enough that 2018 RPS procurement is lower cost than RPS procurement in 2020, 2021, or 2025.

FIGURE L-11: Relative NPVRR of portfolios considered for RPIP



While least-cost, least-risk analysis is not presented in the RPIP, PGE made use of the IRP portfolio scoring methodology in order to determine the portfolios for consideration in the RPIP. This portfolio scoring is summarized in Table L-4. To show a range of possible outcomes, PGE selected the two top performing portfolios for inclusion in the RPIP (*RPS Wind 2018* and *RPS Wind 2018 + Staged RPS 2030*, or "Utilized Bank – Wind" and "Staged Build – Wind" as they are referred to in the RPIP, respectively). In addition, two portfolios in the RPIP consider the potential impact of solar procurement on incremental costs. These portfolios, "Utilized Bank – Diverse" and "Staged Build – Diverse," were not considered in the IRP because the RPS resource comparison suggested that wind resources were more economic than solar resources in the Action Plan time horizon.

TABLE L-4: Portfolio scoring of candidate RPIP portfolios

	Metric Weighting	50%	16.7%	16.7%	16.7%	
Rank	IRP Portfolio Name	Cost Score	Severity Score	Variability Score	Durability Score	Weighted Score
1	**RPS Wind 2018 (RPIP: "Utilized Bank – Wind")**	**100**	**100**	**0**	**100**	**83**
2	**RPS Wind 2018 + Staged RPS 2030 (RPIP: "Staged Build – Wind")**	**68**	**71**	**39**	**50**	**61**
3	RPS Wind 2021	25	41	94	50	43
4	RPS Wind 2020	8	9	94	50	29
5	RPS Wind 2025	0	0	100	0	17

APPENDIX M. Evaluation of Five Renewable Supply Options (DNV GL)

DNV·GL

INTEGRATED RESOURCE PLANNING

Evaluation of Five Renewable Supply Options

Portland General Electric Company

Document No.: 703337-USPO-T-01-C
Date: 25 November 2015

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Reference to part of this report which may lead to misinterpretation is not permissible.

Issue	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	6 November 2015	DRAFT	C. Elkinton	C. Johnson	C. Johnson
B	24 November 2015	DRAFT	C. Elkinton	C. Johnson	C. Johnson
C	25 November 2015	FINAL	C. Elkinton	C. Johnson	C. Johnson

1 INTRODUCTION

Portland General Electric Company ("PGE" or the "Customer") has requested Garrad Hassan America, Inc., (hereafter DNV GL), to provide technical and financial information related to five potential renewable electricity generation projects in support of the Customer's Integrated Resource Planning ("IRP" or "Project").

The information provided in this Technical Note summarizes the results of DNV GL's analyses of these five projects along with the methodologies employed and assumptions made.

2 ABBREVIATIONS AND TERMINOLOGY

The following abbreviations are used in this document:

Abbreviation	Meaning
AC	Alternating Current
aMW	Average Megawatts – the total annual production divided by the number of hours per year
BOP	Balance of Plant
DC	Direct Current
EPC	Engineering, Procurement, Construction
IEA	International Energy Agency
IRP	Integrated Resource Planning
O&M	Operations and Maintenance
PGE	Portland General Electric
PTC	Production Tax Credit
PV	Photovoltaic
Wp	Watts Peak – the measure of DC output under full solar radiation

The Average Capacity of the energy projects discussed herein is given in average megawatts (aMW), which is calculated by dividing the total production for a year by the number of hours in a year. This is different than the project's Nameplate Capacity, which is discussed below in units of megawatts (MW).

The solar industry tends to base its calculations on DC electricity, whereas utilities tend to prefer to work in AC electricity. In order to convert the requested solar parameters into AC units, a DC-to-AC conversion factor of 1.2 was used. This value is commonly seen in the industry; however, for a more accurate value for a given project, a site-specific and technology-specific evaluation is required.

Within this report, solar cost results referenced to watts peak (e.g. $/Wp) are based on DC power, whereas cost results referenced to watts (e.g. $/MW) have been converted to AC power.

3 SUMMARY OF THE WORK

DNV GL was asked to provide numerical values for specific technical and financial parameters that specify five renewable energy projects under consideration by PGE in its IRP. This section describes the methodology and assumptions DNV GL used to determine these numerical values.

The five renewable energy projects under consideration are defined as follows:

Project Name	Location	Average Capacity	Generation Technology
Coos Bay Offshore Wind	Offshore from Coos Bay, Oregon	30 aMW	Wind (Offshore)
Ione Wind	Ione, Oregon	116 aMW	Wind
Central MT Wind	Montana East of Rockies Along Colstrip Line	100 aMW	Wind
Christmas Valley Solar 1	Christmas Valley, Oregon	25 aMW	Solar (fixed tilt)
Christmas Valley Solar 2	Christmas Valley, Oregon	25 aMW	Solar (single axis tracking)

It is noted that the Coos Bay Offshore Wind project is a real project under development by Principle Power. This project is still in the early stages of development, but where possible, actual project specifications have been used herein.

To DNV GL's knowledge, the remaining 4 projects are not currently under development. As such, DNV GL has developed a set of specifications for these projects considered to represent the technologies and practices currently in use today.

3.1 Technical Parameters

3.1.1 Capacity

The Nameplate Capacity is the name-plate generation capacity of the project (in megawatts) needed to meet the required Average Capacity.

3.1.1.1 Results

- Coos Bay Offshore Wind: 72 MW
- Ione Wind: 338 MW
- Central MT Wind: 236 MW
- Christmas Valley Solar 1: 115 MW
- Christmas Valley Solar 2: 103 MW

3.1.1.2 Methodology

For all projects, the Nameplate Capacity is calculated by dividing the Average Capacity by the Capacity Factor.

3.1.1.3 Assumptions

Assumes Average Capacities provided by the Customer (see table above).

3.1.2 Capacity Factor

3.1.2.1 Results

- Coos Bay Offshore Wind: 42%
- Ione Wind: 34%
- Central MT Wind: 42%
- Christmas Valley Solar 1: 21.7%
- Christmas Valley Solar 2: 24.2%

3.1.2.2 Methodology

- Wind projects: Gross energy is based on the power curve noted below and assumed mean wind speed (see assumptions below). Net energy includes typical energy loss factors for an offshore wind farm. The net Capacity Factor was calculated as the ratio of the net energy to the product of the Average Capacity and 8760 hours per year.
- Solar projects: Meteorological data were obtained from SolarAnywhere for the requested project area. The PVsyst software was used to calculate net energy, assuming spacing and loss factors considered reasonable for the region and type of technology. The DC net capacity factor was calculated as the ratio of the net energy to the product of the Average Capacity and 8760 hour per year. The reported AC net Capacity Factor was calculated by applying a DC/AC ratio of 1.2, which is considered reasonable for this region.

3.1.2.3 Other Assumptions

- Coos Bay Offshore Wind: Mean wind speed of approximately 9 m/s, which is based on preliminary mesoscale mapping
- Ione Wind: Mean wind speed of approximately 6.6 m/s, which is based on extensive wind resource analysis and experience in the region
- Central MT Wind: Mean wind speed of approximately 8.2 m/s, which is based on extensive wind resource analysis and experience in the region
- Christmas Valley Solar 1: Result given in AC based on DC capacity factor of 18.1% with DC/AC ratio of 1.2. Assumed 30 deg tilt, due south orientation, Normalized by dc capacity, assumed Performance Ratio of 79.5%, solar resource based on experience, includes loss factor for inverter clipping.

- Christmas Valley Solar 2: Result given in AC based on DC capacity factor of 20.2% with DC/AC ratio of 1.2. Assumed horizontal single axis tracking oriented due south, Normalized by dc capacity, assumed Performance Ratio of 78.6%, solar resource based on regional irradiation data, includes loss factor for inverter clipping.

3.1.3 Power curve

3.1.3.1 Results

- Coos Bay Offshore Wind: The MHI Vestas V164-8.0MW turbine was identified as representative of the technologies being considered for this project.
- Ione Wind: The GE 2.0-116 turbine was identified as representative of the type of technology typically utilized in projects with this wind regime [1].
- Central MT Wind: The GE 2.0-116 turbine was identified as representative of the type of technology typically utilized in projects with this wind regime [1].

3.1.3.2 Methodology

Identified example of turbine likely to be utilized in requested regions and wind conditions.

3.1.3.3 Other Assumptions

- Coos Bay Offshore Wind: This is the turbine on which the project design is currently based.
- Ione Wind: This is an example of a turbine that is appropriate for the wind regime and consistent with latest technology.
- Central MT Wind: This is an example of a turbine that is appropriate for the wind regime and consistent with latest technology.

3.1.4 Expected forced outage rate

3.1.4.1 Results

- Coos Bay Offshore Wind: 2.5%
- Ione Wind: 1%
- Central MT Wind: 1%
- Christmas Valley Solar 1: 1%
- Christmas Valley Solar 2: 1%

3.1.4.2 Methodology

These factors are based on typical industry values and cover balance of plant availability; not included are turbine availability, grid availability (forced and planned outages), and curtailment. It is noted that all of these factors are included in the losses accounted for in the Net Capacity Factors presented above.

3.1.4.3 Other Assumptions

Standard assumed value; grid availability is excluded.

3.1.5 Panel efficiency

3.1.5.1 Results

- Christmas Valley Solar 1: 15.5-16%
- Christmas Valley Solar 2: 15.5-16%

3.1.5.2 Methodology

Based on typical industry values from top-tier panel suppliers.

3.1.5.3 Other Assumptions

This assumes 72 cell panels, 290 w - 310 w.

3.1.6 Inverter efficiency

3.1.6.1 Results

- Christmas Valley Solar 1: 98% - 99%
- Christmas Valley Solar 2: 98% - 99%

3.1.6.2 Methodology

Based on typical industry values.

3.1.6.3 Other Assumptions

This assumes typical aggregate loss factors. Transformers add an additional 1% loss.

3.1.7 Maintenance cycle and average maintenance days

3.1.7.1 Results

- Coos Bay Offshore Wind: Once every 12 months, 4 days per turbine
- Ione Wind: Semi-annual, 60-80 hours per turbine
- Central MT Wind: Semi-annual, 60-80 hours per turbine
- Christmas Valley Solar 1: 3 days per year plus quarterly maintenance (at night)
- Christmas Valley Solar 2: 3 days per year plus quarterly maintenance (at night)

3.1.7.2 Methodology

Based on typical industry values.

3.1.7.3 Other Assumptions

- Coos Bay Offshore Wind: Industry standard, this does not include various inspections
- Ione Wind: Industry standard in US
- Central MT Wind: Industry standard in US
- Christmas Valley Solar 1: maintenance occurs at night, minimal inverter maintenance
- Christmas Valley Solar 2: maintenance occurs at night, minimal inverter maintenance

3.1.8 Approximate footprint

3.1.8.1 Results

- Coos Bay Offshore Wind: 30-40 acres/MW
- Ione Wind: 80 acres/MW
- Central MT Wind: 80 acres/MW
- Christmas Valley Solar 1: 5 acres/MW
- Christmas Valley Solar 2: 7 acres/MW

3.1.8.2 Methodology

Based on typical industry values.

3.1.8.3 Other Assumptions

- Offshore wind project: Based on Block Island (Rhode Island), Rampion (UK), and Kentish Flats Extension (UK)
- Onshore wind projects: Typical in the US
- Solar projects: Standard industry assumption. Trackers need additional area

3.1.9 Construction period, once permitted

3.1.9.1 Results

- Coos Bay Offshore Wind: 18-24 months
- Ione Wind: 10 months
- Central MT Wind: 9 months
- Christmas Valley Solar 1: 6-8 months

- Christmas Valley Solar 2: 6-8 months

3.1.9.2 Methodology

Based on typical industry values.

3.1.9.3 Other Assumptions

- Offshore wind project: Construction period only, assumes financing is also secured
- Onshore wind projects: Based on DNV GL expected durations for construction tasks
- Solar projects: Largely dependent upon EPC contractor man-loading, and also weather dependent

3.2 Financial Parameters

The financial parameters below were requested by the Customer. All cost figures presented herein are in 2015 dollars.

3.2.1 Total overnight capital cost, including EPC and owner's costs

3.2.1.1 Results

- Coos Bay Offshore Wind: $504M ($7,000/kW)
- Ione Wind: $558M ($1,680/kW)
- Central MT Wind: $401M ($1,700/kW)
- Christmas Valley Solar 1: $206M ($1,790/kW)
- Christmas Valley Solar 2: $204M ($1,980/kW)

3.2.1.2 Methodology

The total overnight capital cost is the cost to instantaneously develop and construct a project. Financing costs are excluded. The figures reported here are based on typical costs per unit of energy seen in recent projects and and include estimates for all major project cost categories. Additional background on capital costs can be found in the U.S. Department of Energy's 2014 Wind Technologies Market Report [2].

3.2.1.3 Other Assumptions

- Coos Bay Offshore Wind: Based on industry expectations for floating offshore wind projects
- Ione Wind: Based on the following break-down:
  - $1,000/kW turbine
  - $450/kW EPC
  - $230/kW development/contingency/etc
- Central MT Wind: Based on the following break-down:

  - $1,000/kW turbine
  - $470/kW EPC
  - $230/kW development/contingency/etc
- Christmas Valley Solar 1: Assumes $2.15 per Wp, which includes construction costs and reflects fixed-tilt technologies and the larger utility-scale PV projects that require financing
- Christmas Valley Solar 2: Assumes $2.38 per Wp, which includes construction costs and reflects single axis tracking technologies and the larger utility-scale PV projects that require financing
- These estimates do not include the cost of capital, taxes, or other financing costs.
- These estimates do not include financial impacts associated with any tax credits (e.g. the Production Tax Credit, PTC), or potential impacts from other revenue sources.
- The "development/contingency/etc" cost estimates provided above cover a nominal level of development spending and typical contingency above the price of the construction contract and are included here to reflect more complete project costs. These values are inherently project specific.

3.2.2 Standard deviation from average total overnight capital cost

3.2.2.1 Results

- Coos Bay Offshore Wind: Expected range: $5M-$8M/MW
- Ione Wind: Standard deviation: $0.350M/MW
- Central MT Wind: Standard deviation: $0.350M/MW
- Christmas Valley Solar 1: Expected range: $1.7M-$ 1.9M/MW
- Christmas Valley Solar 2: Expected range: $1.9M-$-2.1M/MW

3.2.2.2 Methodology

- Offshore wind project: The range for the overnight costs represents the expected range of floating offshore wind projects based on previous cost studies for floating wind projects in Europe. The estimate provided in Section 3.2.1.1 above is considered to represent a project installed off Oregon.
- Onshore wind project: DNV GL maintains a large database of wind project costs. These expected value and standard deviation were determined based on projects of a similar size and in the Pacific Northwest region.
- Solar projects: Range based on recent project costs using similar technologies in the Western U.S..

3.2.2.3 Other Assumptions

- Coos Bay Offshore Wind: floating offshore wind assumed to be at the high end of the range
- Ione Wind: Standard deviation is high due to limited availability of recent data of similar projects in this region

- Central MT Wind: Standard deviation is high due to limited availability of recent data of similar projects in this region
- Christmas Valley Solar 1: A cost range of $2.00 -$ 2.30 per Wp is expected for fixed-tilt projects. This is considered to represent the range of typical projects in the Pacific Northwest; it does not capture the extremes of the possible range.
- Christmas Valley Solar 2: A cost range of $2.25 -$ 2.50 per Wp is expected for single-axis tracking projects. This is considered to represent the range of typical projects in the Pacific Northwest; it does not capture the extremes of the possible range.

3.2.3 Escalation rate for capital costs over next 20 years, if different from inflation

3.2.3.1 Results

The following table and plot show DNV GL's projection for the percentage decrease in overnight capital cost for the offshore wind, onshore wind, and solar PV projects PGE has requested. These results were informed by the IEA's Annual Energy Outlook (2013) [3] and by DNV GL's experience with utility-scale project cost trends.

No on-going capital costs are assumed for a given project after it achieves commercial operation.

Table 3-1 Percentage of 2015 Overnight Cost (based on $2015)

Year	Offshore Wind (floating) % (2015)	Onshore Wind % (2015)	PV % (2015)
2015	100%	100%	100%
2016	95%	99%	
2017	90%	98%	
2018	85%	97%	
2019	81%	95%	
2020	76%	94%	91%
2021	72%	93%	
2022	70%	92%	
2023	68%	91%	
2024	66%	90%	
2025	64%	90%	83%
2026	63%	89%	
2027	61%	89%	
2028	60%	89%	
2029	58%	88%	
2030	57%	88%	75%
2031	56%	88%	
2032	54%	87%	
2033	53%	87%	
2034	52%	87%	
2035	50%	87%	68%
2036	49%	87%	
2037	48%	86%	
2038	46%	86%	
2039	45%	86%	
2040	44%	86%	62%

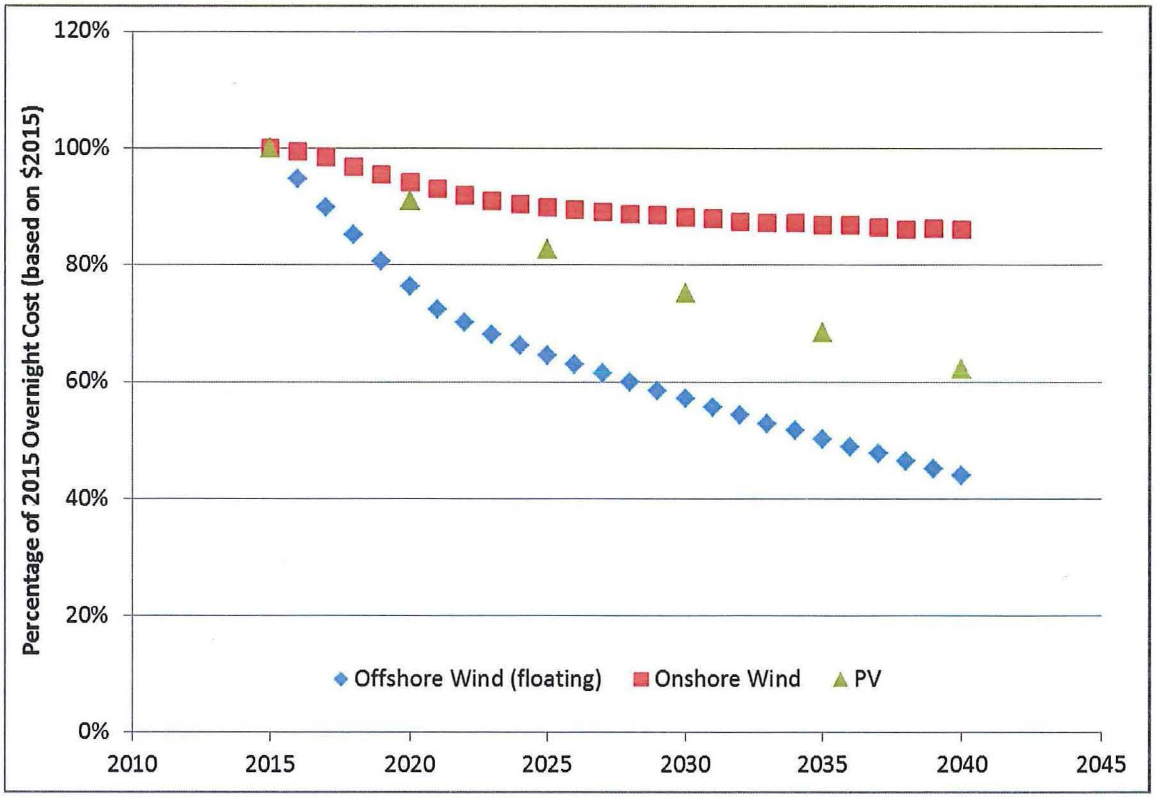


Figure 3-1 Percentage of 2015 Overnight Cost (based on $2015)

3.2.4 Fixed O&M

3.2.4.1 Results

- Coos Bay Offshore Wind: $165,000/MW/yr
- Ione Wind: $45,000/MW/yr
- Central MT Wind: $45,000/MW/yr
- Christmas Valley Solar 1: $9,900/MW/yr
- Christmas Valley Solar 2: $10,000/MW/yr

3.2.4.2 Methodology

Costs in this category are related to scheduled maintenance (e.g. annual or semi-annual maintenance), general facilities maintenance (e.g. roads and buildings), and administrative expenses (e.g. lease payments, labor, etc). These costs are subdivided further in Section 3.2.5.1 below.

3.2.4.3 Other Assumptions

These estimates are based on typical values seen on wind and solar projects and are considered to be representative of projects in the area(s) of interest. The values presented here are averages over the economic life of the project (see Section 3.2.9.1 below).

3.2.5 Breakdown of fixed O&M costs including, but not limited to, service contracts and warranty costs, royalty payments, and labor

3.2.5.1 Results

- Coos Bay Offshore Wind:
    - Vessels: \$53,000/MW
    - Parts: \$11,000/MW
    - Labor: \$22,000/MW
    - Onshore support: \$22,000/MW
    - BOP O&M: 3,000/MW
    - Insurance: \$16,000/MW
    - Lease payments: \$28,000/MW
    - Other: \$10,000/MW
- Ione Wind:
    - Scheduled Turbine O&M: \$17,000/MW
    - BOP O&M: \$3,000-5,000/MW
    - Utilities: \$1,000/MW
    - Project Management Administration: \$3,000/MW
    - Generation Charges: \$1,500/MW
    - Land Lease: \$5,500/MW
    - Insurance: \$3,000/MW
    - Property Taxes: \$5,500/MW
    - Professional Advisory: \$3,000/MW
    - Other G&A: \$1,500/MW
- Central MT Wind:
    - Scheduled Turbine O&M: \$17,000/MW
    - BOP O&M: \$3,000-5,000/MW

    - Utilities: $1,000/MW
    - Project Management Administration: $3,000/MW
    - Generation Charges: $1,500/MW
    - Land Lease: $5,500/MW
    - Insurance: $3,000/MW
    - Property Taxes: $5,500/MW
    - Professional Advisory: $3,000/MW
    - Other G&A: $1,500/MW
- Christmas Valley Solar 1:
    - Module cleaning: $5,000-6,500/MW
    - Other: $3,400-4,900/MW
- Christmas Valley Solar 2:
    - Module cleaning: $5,000-6,500/MW
    - Other: $3,500-5,000/MW

3.2.5.2 Methodology

These estimates are based on typical costs from projects using similar technologies in the US.

Additional information on some of these charges is provided below:

- Scheduled Turbine O&M: annual or semi-annual service
- BOP O&M: maintenance of the physical plant
- Utilities: Electricity, water, sewer, etc. needed to operate the project facilities
- Project Management Administration: On-site and off-site project and asset management
- Generation Charges: Interconnection charges and parasitic power
- Professional Advisory: outside services such as engineering, tax, and legal services
- Other G&A: General and administrative costs not captured above

3.2.5.3 Other Assumptions

- Offshore wind project: Based on European experience, adjusted for floating project
- Onshore wind projects: Based on DNV GL database
- Solar projects:
    - Cleaning: $1,500-$2,000/MWp;

  - Budget includes: System monitoring, regular visual inspections, preventative maintenance, periodic electrical testing, inventory management, occasional medium voltage and inverter work; on-site staff is typically present for these services on projects larger than 25 MWp.

3.2.6 Non fuel variable O&M

3.2.6.1 Results

- Coos Bay Offshore Wind: Not applicable
- Ione Wind: Not applicable
- Central MT Wind: Not applicable
- Christmas Valley Solar 1: Not applicable
- Christmas Valley Solar 2: Not applicable

3.2.6.2 Methodology

Based on discussion with the Customer, project operations and maintenance costs are considered to be covered under either "Fixed O&M" or "Ongoing expected Capital Additions or maintenance accrual". As such, no costs are expected in this category.

3.2.6.3 Other Assumptions

None.

3.2.7 Approximate capital drawdown schedule

3.2.7.1 Results

- Offshore wind project:
  - Approx. 15% down
  - 65% for deliveries to port
  - 5% for construction
  - 15% for commissioning (pro rata)
- Onshore wind projects:
  - Approx. 20% down
  - 50% on Ex-works completion (pro rata)
  - 20% on delivery to site
  - 5% on commissioning
  - 5% on final completion

- Solar projects:
    - Approx. 10% down
    - 80% in monthly progress payments
    - 10% at substantial completion.

3.2.7.2 Methodology

These estimates are based on typical contracts in the wind and solar energy industries.

3.2.7.3 Other Assumptions

- Offshore wind project: Based on known projects, will depend on contractual responsibilities
- Onshore wind projects: Typical for US industry
- Solar projects: Typical for US industry

3.2.8 Ongoing expected Capital Additions or maintenance accrual

DNV GL notes that in this Report and at the request of the Customer, the term "ongoing capital additions" is considered to be synonymous with the term "unscheduled maintenance," which is more commonly used in the wind industry.

3.2.8.1 Results

- Coos Bay Offshore Wind: Included in Fixed O&M (above)
- Ione Wind: $16,500/MW/yr
- Central MT Wind: $16,500/MW/yr
- Christmas Valley Solar 1: $2,400/MW/yr
- Christmas Valley Solar 2: $2,500/MW/yr

3.2.8.2 Methodology

Costs in this section are associated with the replacement or repair of major components [4]. These are typically considered to be unscheduled costs [5].

3.2.8.3 Other Assumptions

The values in this section are based on typical values seen within the wind and solar industries. The values presented here are averages over the economic life of the project (see Section 3.2.9.1 below).

- Coos Bay Offshore Wind: Small project, with likely shared vessel resources, so cannot separate scheduled and unscheduled maintenance costs
- Ione Wind: Based on DNV GL database, 25-year average value, does not include unscheduled BOP maintenance

- Central MT Wind: Based on DNV GL database, 25-year average value, does not include unscheduled BOP maintenance
- Christmas Valley Solar 1: Assumes $2.90 per kWp/yr; this is driven by inverter repair/replacement
- Christmas Valley Solar 2: Assumes $3.00 per kWp/yr; this is driven by inverter repair/replacement

3.2.9 Design life: years

3.2.9.1 Results

- Coos Bay Offshore Wind: 25 years
- Ione Wind: 25 years
- Central MT Wind: 25 years
- Christmas Valley Solar 1: 30 years
- Christmas Valley Solar 2: 30 years

3.2.9.2 Methodology

Based on industry-standard values for the specific generating technology.

3.2.9.3 Other Assumptions

None.

3.2.10 Decommissioning accrual

3.2.10.1 Results

- Coos Bay Offshore Wind: $1,600,000/year
- Ione Wind: $0.00
- Central MT Wind: $0.00
- Christmas Valley Solar 1: $0.00
- Christmas Valley Solar 2: $0.00

3.2.10.2 Methodology

- Coos Bay Offshore Wind: Decommissioning costs for offshore wind projects have been found to equate to 7-10% of the capital cost. A bond is required to cover the cost of decommissioning the portion of the project that us under BOEM jurisdiction (see 30 C.F.R. §585). The figure presented here assumes a decommissioning cost equal to 8% of the capital cost, divided into equal annual over the 25-year design life of the project (2015 dollars).

- Onshore wind projects: Decommissioning cost is widely assumed to be offset by salvage value of used components. A bond may be required to accumulate funds, although this is uncommon for onshore wind projects.
- Solar projects: Decommissioning cost is widely assumed to be offset by salvage value of used components. A bond may be required to accumulate funds.

3.2.10.3 Other Assumptions

None.

4 REFERENCES

[1] GE Power & Water, Technical Documentation Wind Turbine Generator Systems 2.0-116 - 50 Hz and 60 Hz, Calculated Power Curve and Thrust Coefficient, *Confidential*, dated 2014

[2] U.S. Department of Energy, 2014 Wind Technologies Market Report, dated August 2015.

[3] U.S. Energy Information Administration, Annual Energy Outlook 2013 with projections to 2040, dated April 2013.

[4] PGE, Accounting Practices and Procedures Document: Wind Generation and Related Equipment, APPD 4-100-06, dated 26 November 2012.

[5] DNV GL, Turbine O&M costs, 703337-USPO-X-02, *Confidential*, dated 25 November 2015.

APPENDIX N. WECC Resource Expansion Detail

N.1 Long-Term WECC Projections

Table N-1 details the long-term net resource additions—by area—in the Western Electricity Coordinating Council (WECC) under reference case CO_2 futures. The period of the analysis is 2017-2050. PGE enforces Renewable Portfolio Standards in all applicable States. Net additions are equal to resource additions net of retirements of old power plants.

TABLE N-1: Resources by state, average annual capacity, GW

	Present	2025	2030	2035	2040	2045	2050	Total Net Additions 2017-'50
Alberta (Canada)	16,108	18,237	20,176	21,893	20,786	21,954	22,728	6,620
Arizona	28,770	32,620	36,606	38,982	39,090	37,696	37,759	8,989
British Columbia (Canada)	16,831	18,742	19,242	20,203	20,190	20,191	20,964	4,134
California	83,492	88,500	95,055	107,392	114,341	114,504	119,074	35,582
Colorado	16,410	18,720	21,141	21,619	23,838	26,308	28,137	11,727
Idaho	5,274	5,843	6,042	6,448	6,402	6,403	6,609	1,334
Montana	6,054	5,645	5,648	5,955	5,942	5,943	5,944	(110)
Nevada	7,769	8,423	10,013	10,622	10,166	13,564	19,124	11,356
New Mexico	12,441	13,563	14,492	16,211	16,665	18,016	19,811	7,370
Oregon	16,438	17,928	19,614	21,310	21,952	22,630	22,632	6,194
Utah	8,718	11,052	11,968	13,747	15,678	16,631	18,395	9,677
Washington	31,032	33,293	34,403	35,104	33,600	32,463	32,464	1,432
Wyoming	7,941	10,743	11,292	13,046	14,739	16,349	17,701	9,760
Total	**257,279**	**283,309**	**305,693**	**332,532**	**343,390**	**352,652**	**371,343**	**114,064**
- of which PNW	**52,745**	**57,064**	**60,059**	**62,862**	**61,954**	**61,495**	**61,706**	**8,960**

Table N-2 shows the average annual capacity available for dispatch by technology under reference case CO_2 futures. It highlights the progressive reduction of traditional baseload capacity like coal and nuclear, with the latter projected to be completely retired by 2050. PGE did not present any new coal and nuclear plant additions as an option in this IRP because of federal restrictions under the Clean Air Act and the continued lack of permanent storage for nuclear waste. Technological and legal break-throughs might change PGE's modeling approach in future IRPs.

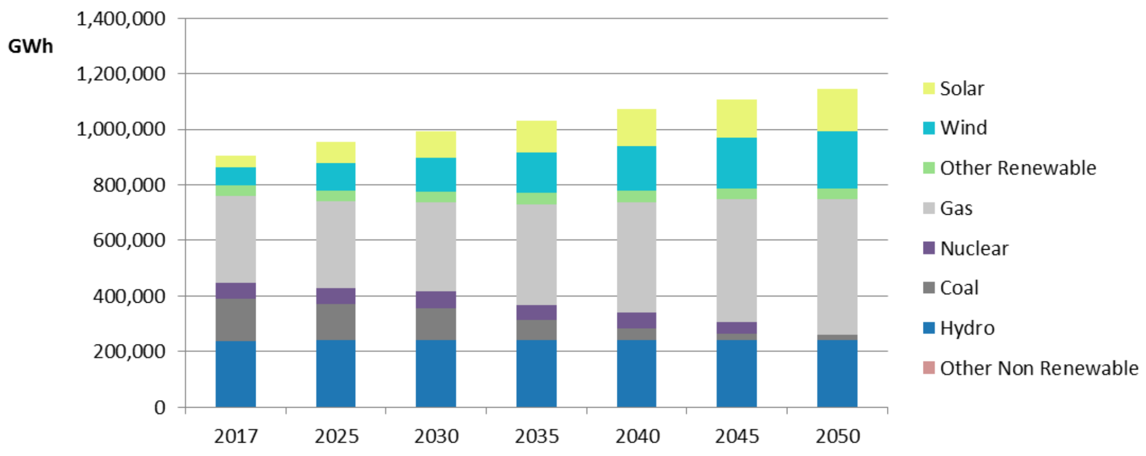
TABLE N-2: Resources by technology, average annual capacity, GW

	Present	2025	2030	2035	2040	2045	2050	Total Net Additions
Hydro	70,930	75,975	77,725	77,975	77,974	77,975	77,975	7,046
Gas	94,329	92,907	102,659	114,163	114,511	119,933	129,747	35,418
Coal	35,702	29,410	21,649	19,663	17,068	15,109	15,109	(20,593)
Nuclear	7,315	7,315	7,315	7,315	7,315	4,787	-	(7,315)
Renewables								
Wind	24,810	37,876	45,476	53,308	59,290	65,374	74,162	49,352
Solar	18,526	33,405	43,842	52,463	59,641	62,036	66,911	48,385
Other	6,224	6,802	7,206	7,912	7,912	7,912	7,912	1,689
Other (F.O. etc.)	170	170	170	170	170	170	170	-

Table N-1, Table N-2, and Figure N-1 summarize the net resource changes; both additions and retirements are included. Retirements comprise coal plants and older, less efficient, fuel oil and gas combustion turbines.

Figure N-1 shows the resulting simulated resource mix—after economic dispatch under Reference Case conditions. It highlights the penetration of renewables—more precisely solar and wind—and natural gas-fired, which offset the reduction of coal capacity.

FIGURE N-1: WECC resource dispatch mix by technology, GWh



The long-term electricity prices for the Pacific Northwest resulting from PGE's WECC expansion in AURORAxmp are provided in Appendix H, AURORA Market Prices.

In this IRP, PGE performed two additional WECC studies (in addition to the Reference Case) to test the impact on the projected WECC resource build out of two varied carbon policies:

- No CO_2 tax: representative of a future in which CO_2 emissions are not explicitly priced emissions do not incur explicit costs, yet CPP constraints remain in effect (state and provincial

CO_2 regimes remain in-place).

- High CO_2 tax: which imposes more stringent targets to limit CO_2 emissions resulting in $28 per short ton of CO_2 emissions (nominal) starting in 2022 and escalating at six percent annually through 2027 and eight percent annually thereafter through 2050.

Table N-3 shows the cumulative net resource additions from 2017 to 2050 by CO_2 price future (total nameplate capacity by technology). Appendix H, AURORA Market Prices, provides long-term electricity prices arising from these studies.

TABLE N-3: WECC resource additions by 2050 by carbon policy, nameplate capacity, GW

Resource Added	Reference	No CO_2 Tax	High CO_2 Tax
Hydro	8.32	8.32	8.32
Gas	36.88	39.24	41.76
Coal	-15.44	-15.44	-15.44
Nuclear	0.00	0.00	0.00
Renewables			
Wind	49.37	26.72	65.96
Solar	37.28	35.84	41.92
Other	0.06	0.06	0.06
Other (F.O. etc.)	0.09	0.09	0.09
Total	116.56	94.83	142.67

The comparison of the three simulations leads to the following:

- In all carbon futures, coal is retired. This is a result embedded in the Wood Mackenzie data base, reflective of the fact that the overall environmental upgrades for existing coal plants are not competitive with alternative investments in efficient gas plants, given the projected Reference Case prices.
- The No CO_2 tax future builds materially less renewables because they are less competitive when compared to natural gas-fired plants under this state of the world. Natural gas-fired plants provide both energy and capacity across all hours of the year and therefore their modest increase vs. the Reference Case is sufficient to offset the lower renewables build-out.
- The High CO_2 tax future builds the most resources. Renewables help meet energy needs more cheaply, but they do not meet the resource adequacy standards imposed on the WECC. Therefore, generic capacity resources also need to be added to the system.

APPENDIX O. Portfolio Detail

PGE analyzed 21 different portfolios in the 2016 IRP, with the goal of evaluating the performance of various technologies, energy efficiency targets, and the timing of resource actions. Table O-1 outlines which portfolios test each of the variables. Of the 21 portfolios, PGE considered ten as candidates for the Action Plan.

Long-term resource portfolios evaluated in PGE's 2016 IRP are subject to the following constraints:

- Reliability: portfolios meet the reliability standard of a maximum of 2.4 hours of lost load expectation in any single year from 2017 to 2050;[237]
- Environmental: portfolios meet emission limits imposed by current legislation.

Additionally, all portfolios pursue:

- Compliance with Oregon's Renewable Portfolio Standard (RPS) through 2050;
- Inclusion of cost-effective, customer-side options: energy efficiency (EE), demand response (DR), conservation voltage reduction (CVR), and dispatchable standby generation (DSG);
- Retention of all existing power plants until 2050, with the exception of Boardman, which is ceasing its coal operation by the end of 2020, and Colstrip Units 3 and 4, which are removed from the resource stack prior to January 1, 2035;

This appendix lists the detailed composition of each long-term resource portfolio, describing the capacity of each resource added by year through 2040. Portfolios generally test variations on major resource additions through 2025. After that date, most portfolio additions only differ by the timing of incremental renewables resources to comply with the Oregon RPS and incremental generic capacity resources to meet reliability standards (the only exceptions being the Colstrip replacement portfolios).

Nearly all portfolios contain the following common resources from 2017 through 2025:[238]

- At least 239 MWa (297 MW) of new Cost-Effective EE;[239]
- 162 MW of new DR;
- 3 MWa (4 MW) of CVR;
- 30 MW of new DSG, and;
- A minimum of 213 MWa of qualifying resources by 2025 to meet the Oregon RPS.[240]

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[237] Portfolio 1 addresses incremental energy needs with spot market purchases and includes no capacity actions beyond the contributions made by RPS resources. This portfolio does not meet reliability standards and is therefore not a viable strategy for PGE. It serves as a benchmark only.

[238] Gross amounts at the busbar. In this context, PGE reports capacity for customer-side resources as the average of winter and summer peaking capacity.

[239] Represents EE achieved on average across 2025, which is slightly less than the EE achieved by year end 2025. This number is exceeded only in the High EE portfolios.

[240] Portfolio 20 and Portfolio 21 make use of banked RECs to add less than 213 MWa of qualifying renewables by 2025.

Resource options considered in addition to Cost-Effective EE, DR, DSG, and CVR include:

- All Achievable EE;
- Wind located in the Pacific Northwest Columbia Gorge (PNW Wind);
- Wind located in Montana (MT Wind);
- Central Station Solar (Solar);
- Geothermal;
- Biomass;
- Efficient Capacity. For modeling purposes, PGE used an H-class combined-cycle combustion turbine (CCCT) fueled with natural gas as the proxy for efficient capacity resources; and
- Generic Capacity (e.g., seasonal contracts, mid-term/short-term contracts, energy storage, combustion turbines). For modeling purposes, PGE used a frame combustion turbine fueled with natural gas as proxy for generic capacity resources.

Table O-1 lists all portfolios and identifies the specific analyses presented in Chapter 10, Modeling Methodology, that utilize each portfolio.

This appendix also summarizes the performance of each portfolio across five categories of output metrics. Below is a description of the five categories.

1. **Energy position**, which describes how PGE meets demand each year based on the AURORA dispatch simulation for the Reference Case future. A positive Market Position, indicated by an open bar on top of the resource stack, means PGE is a net purchaser across the year.[241] A negative market position (appears below the axis) means that PGE is a net seller across the year.
2. **Reliability**, which describes the key reliability metrics from RECAP:[242]
    - EUE – Expected Unserved Energy in MWh per year;
    - TailVar90 shortage – the average magnitude (MW) of lost load in the top 10th percentile of loss of load events;
    - LOLE – Loss of Load Expectation is the number of hours per year in which a loss of load event is expected to occur. An LOLE of 2.4 hours per year corresponds to a one-day-in-ten years reliability standard. Excluding Portfolio 1, all portfolios add generic capacity annually as needed to meet the reliability standard.
3. **Cost**, which summarizes the NPVRR (net present value revenue requirement) across all futures based on the AURORA dispatch simulation. The dotted line indicates the NPVRR under the Reference Case future.
4. **Carbon**, which describes emissions associated with meeting demand, including market purchases in the Reference Case future. Savings are shown relative to a No Addition scenario

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[241] The 2017 energy market position is inclusive of executed energy index options.

[242] See Chapter 5, Resource Adequacy, for a detailed description of the Renewable Energy Capacity Planning (RECAP) model.

in which no new RPS or capacity additions are modeled. The No Addition scenario does include cost-effective EE and coal retirements.

5. **RPS**, which indicates how PGE meets RPS obligations through RECs generated from existing resources, new resources, unbundled REC purchases, and reliance on the REC bank, while maintaining the REC bank above the risk-based minimum level.

Chapter 10, Modeling Methodology, contains information about portfolio design and RPS compliance strategies. Chapter 12, Modeling Results, provides additional information about portfolio performance.

TABLE O-1: List of portfolios and scope

Name	RPS timing	Banked & unbundled REC usage	Cost of resource adequacy	Montana wind transmission budget	Renewable resource economics	Efficient vs. low capital cost capacity	Colstrip timing economics	Non-cost effective EE	Action Plan Candidate
1. RPS Wind 2018 + No Capacity Action			•						
2. RPS Wind 2018	•		•	•		•			•
3. Efficient Capacity 2021		•				•		•	•
4. Wind 2018 Long									•
5. Wind 2018					•			•	•
6. Diverse Wind 2021				•					
7. Wind 2018 + Solar PV 2021					•				•
8. Geothermal 2021					•				•
9. Boardman Biomass 2021					•				•
10. Wind 2018 + Solar PV 2018					•				•
11. Efficient Capacity 2021 + High EE								•	•
12. Wind 2018 + High EE								•	•
13. Colstrip Wind 2030							•		
14. Colstrip Wind 2035							•		
15. Colstrip Efficient Capacity 2030							•		
16. Colstrip Efficient Capacity 2035							•		
17. RPS Wind 2020	•								
18. RPS Wind 2025	•								
19. RPS Wind 2021	•								
20. Efficient Capacity 2021 Minimum REC Bank		•							
21. Efficient Capacity 2021 20% Unbundled RECs		•							

Portfolio 1: RPS Wind 2018 + No Capacity Action

In addition to the common resource actions, this portfolio adds PNW Wind resources in 2018 and on each compliance stair-step date thereafter, adding: 175 MWa in 2018, 38 MWa in 2025, 43 MWa in 2030, 597 MWa in 2035, 191 MWa in 2040, and 92 and 102 MWa in 2045 and 2050, respectively. This portfolio does not include any additional resource actions. All incremental energy needs are met with spot market purchases. This portfolio does not meet reliability standards and is therefore not a viable strategy for PGE.

TABLE O-2: Portfolio 1 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	-	-	-	-		-		-		-		-

FIGURE O-1: Portfolio 1 cumulative resource additions, capacity (MW)

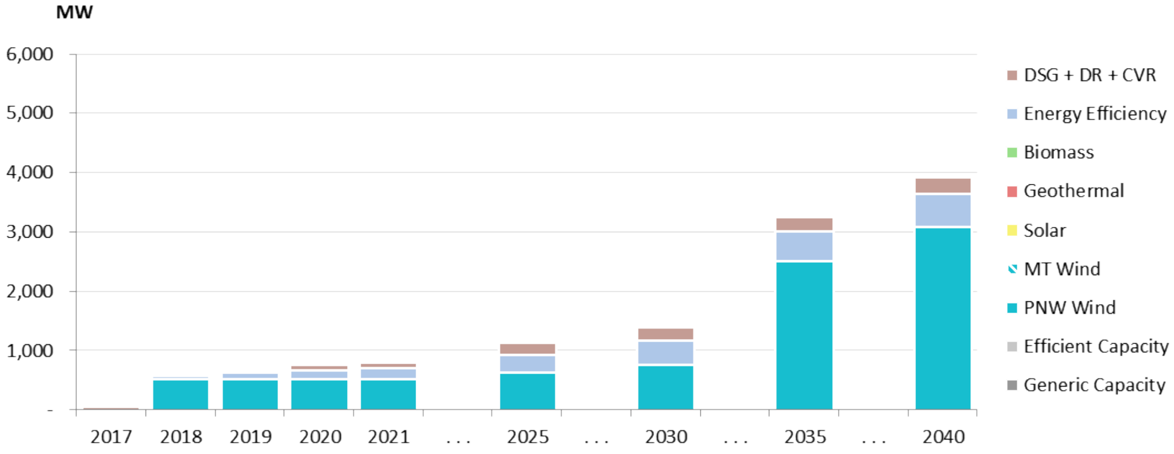
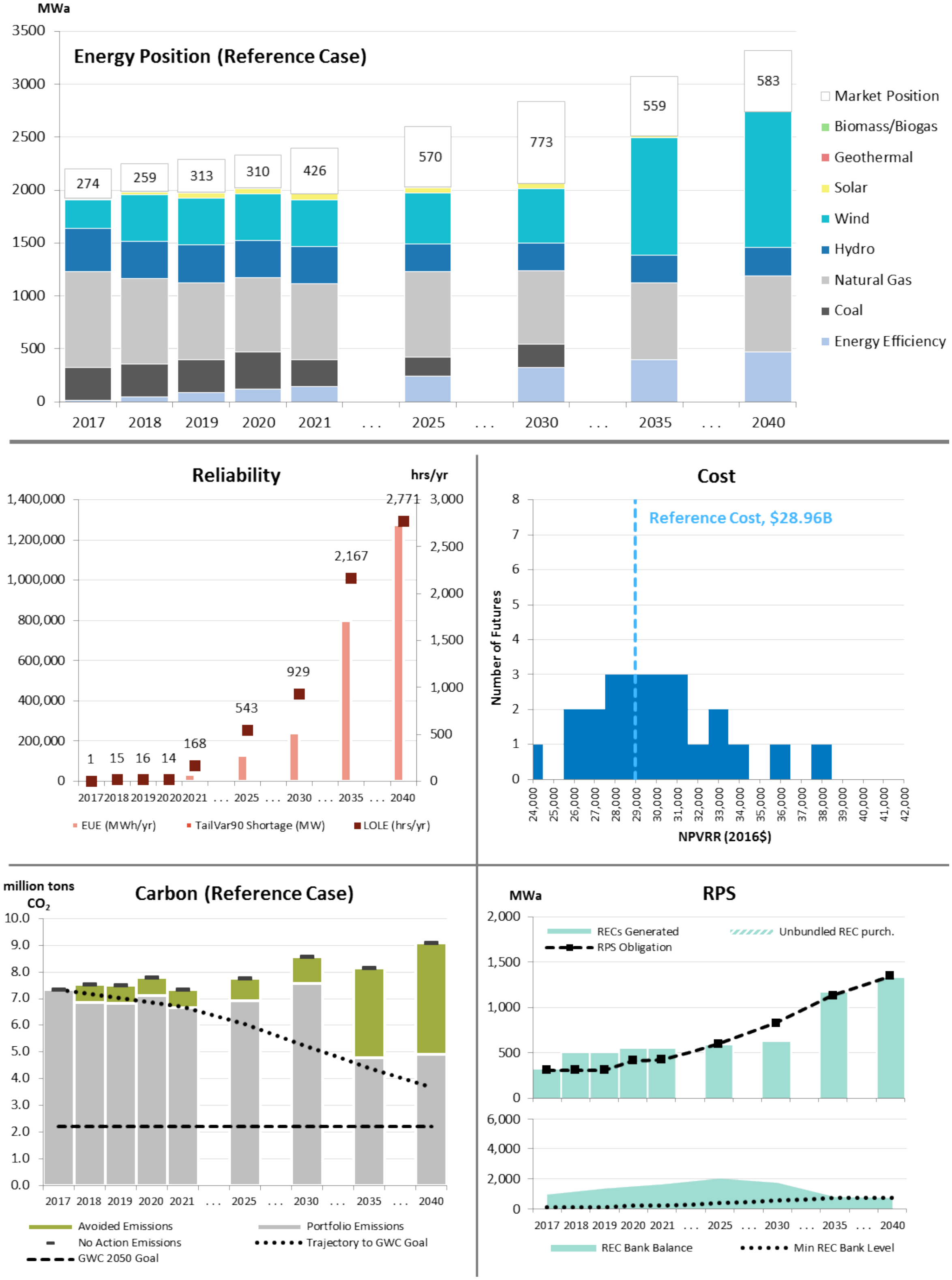


FIGURE O-2: Portfolio 1 output summary



Portfolio 2: RPS Wind 2018

This portfolio is similar to *Portfolio 1*, but includes sufficient generic capacity resources in each year to achieve PGE's resource adequacy standards. Generic capacity is represented by the cost and heat rate characteristics of a natural gas-fired frame combustion turbine, which has reduced fixed costs and a higher heat rate compared to efficient capacity (*Portfolio 3*).

TABLE O-3: Portfolio 2 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	760		1,072		1,253		1,688		1,940

FIGURE O-3: Portfolio 2 cumulative resource additions, capacity (MW)

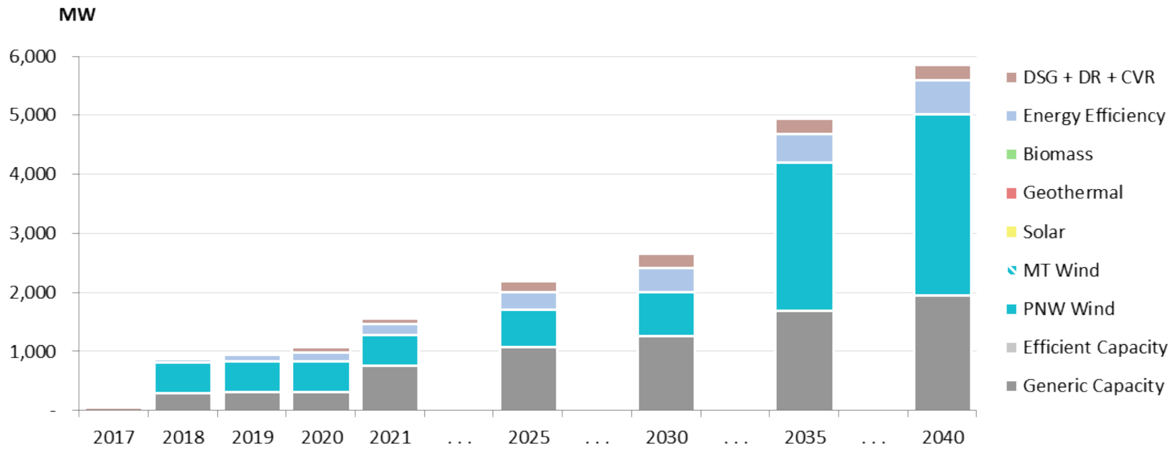
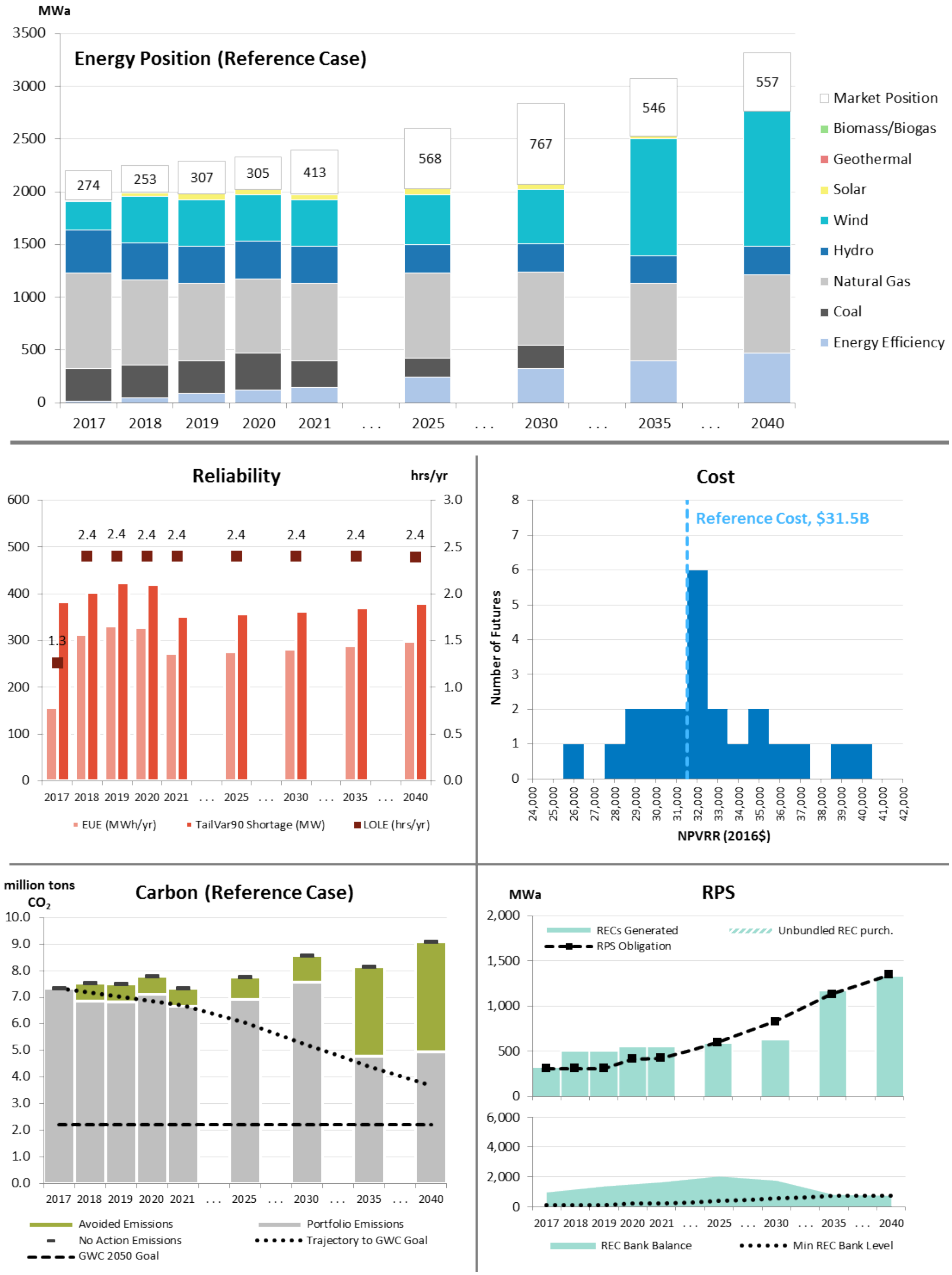


FIGURE O-4: Portfolio 2 output summary



Portfolio 3: Efficient Capacity 2021

This portfolio is equivalent to *Portfolio 2 - RPS Wind 2018*, with a portion of the generic capacity in 2021 replaced by a resource with higher fixed costs and a lower heat rate. PGE models the efficient capacity resource as a natural gas-fired CCCT with an average annual capacity of approximately 389 MW. This portfolio allows PGE to assess the potential costs/benefits of relying on a low-heat rate resource to meet capacity needs.

TABLE O-4: Portfolio 3 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	…	2025	…	2030	…	2035	…	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	389		389		389		389		389
Generic Capacity	-	290	318	318	386		697		877		1,310		1,563

FIGURE O-5: Portfolio 3 cumulative resource additions, capacity (MW)

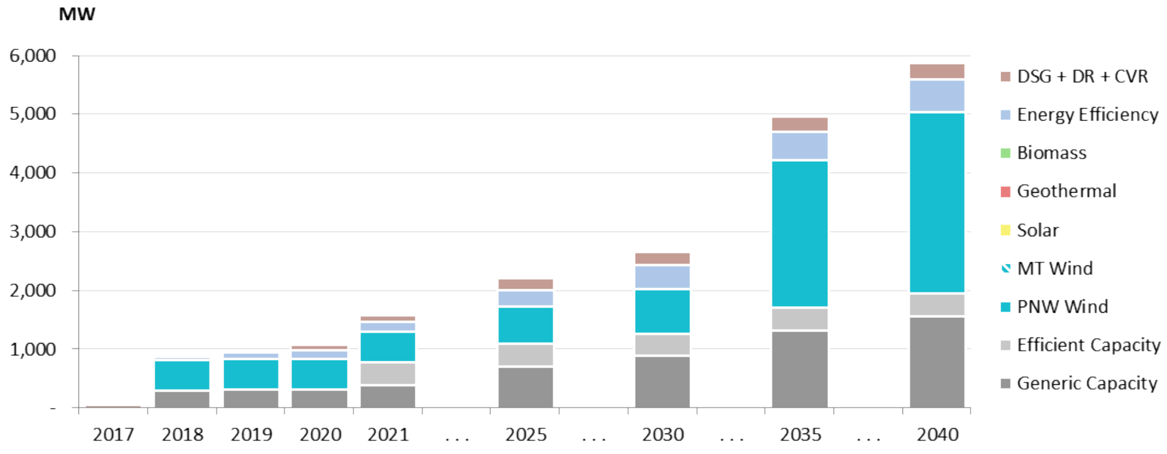
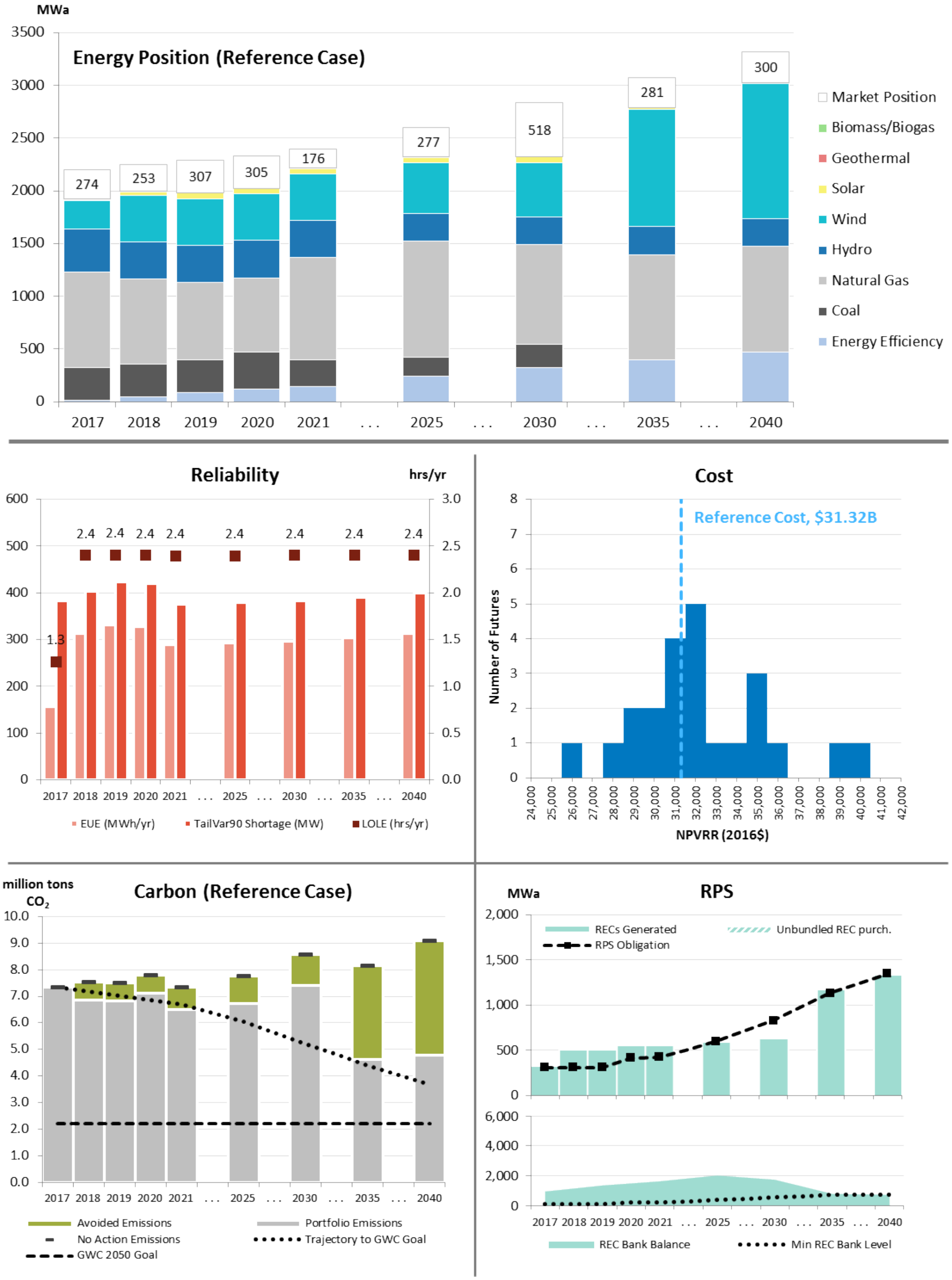


FIGURE O-6: Portfolio 3 output summary



Portfolio 4: Wind 2018 Long

This portfolio is similar to *Portfolio 3 - Efficient Capacity 2021* but achieves the same expected available energy and capacity by adding PNW Wind and generic capacity in 2021 as opposed to a CCCT. Following the 175 MWa wind resource action in 2018, *Portfolio 4 - Wind 2018* Long adds 369 MWa of wind and 374 MW of generic capacity in 2021. Both early renewable additions defer later RPS actions through accumulated banked RECs. This portfolio is included for comparison purposes with *Portfolio 3* to assess the relative cost/benefit of a portfolio composed of PNW Wind relative to a natural gas-fired CCCT resource.

TABLE O-5: Portfolio 4 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	1,599		1,599		1,599		1,599		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	692		1,012		1,203		1,732		1,940

FIGURE O-7: Portfolio 4 cumulative resource additions, capacity (MW)

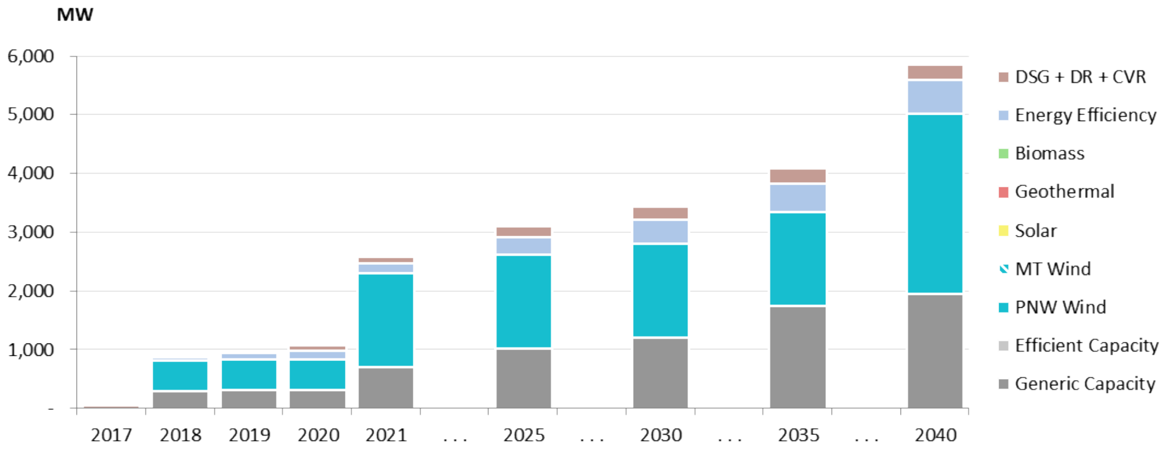
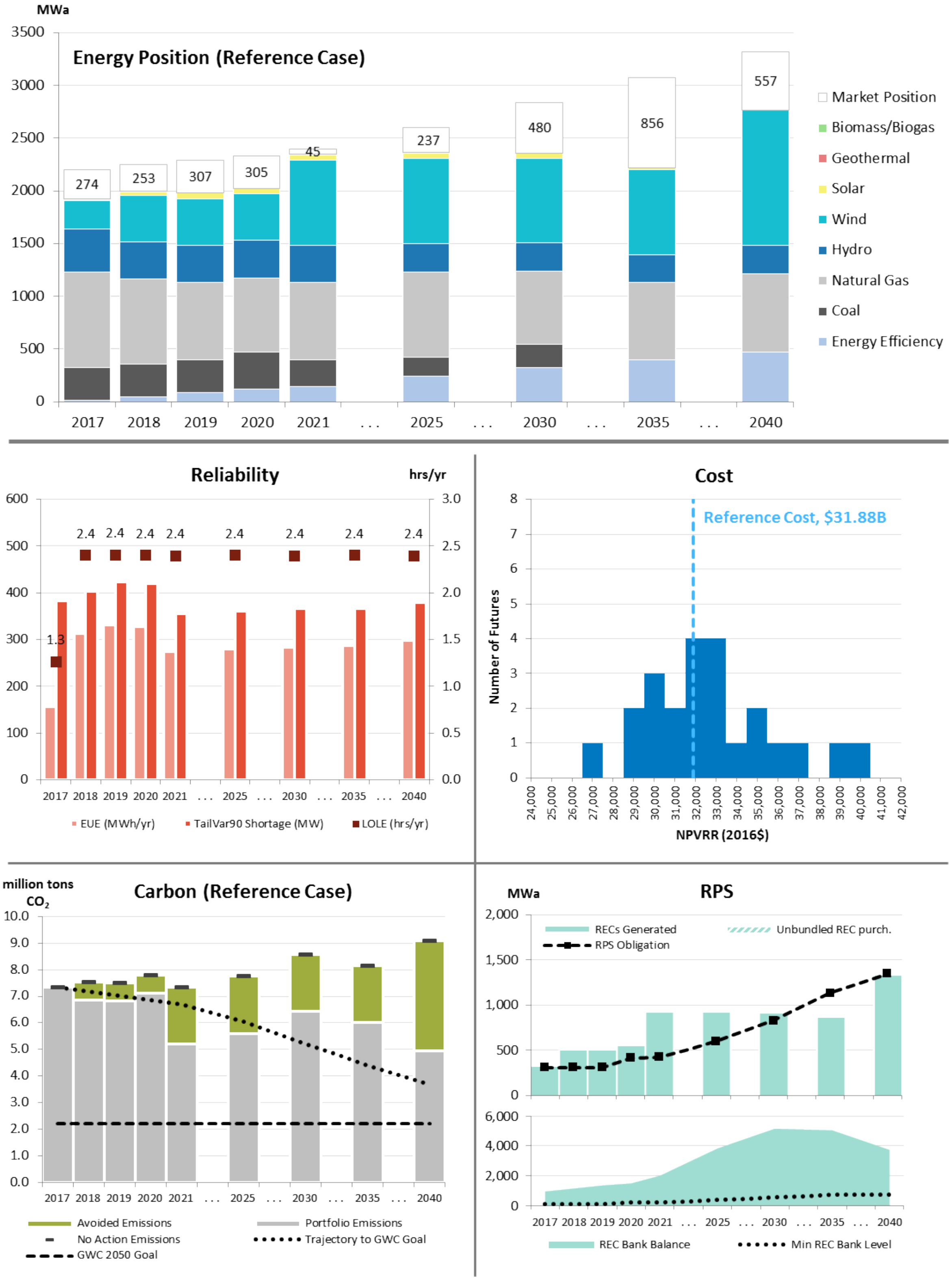


FIGURE O-8: Portfolio 4 output summary



Portfolio 5: Wind 2018

This portfolio is similar to *Portfolio 4 – Wind 2018 Long*, but rather than adding wind in a quantity equivalent to a CCCT on an expected annual average energy basis in 2021, PGE includes a wind resource sized just to satisfy the available energy deficit in that year (approximately 213 MWa). The portfolio adds additional generic capacity in 2021 to achieve resource adequacy.

TABLE O-6: Portfolio 5 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	1,141		1,141		1,141		1,141		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	717		1,038		1,228		1,759		1,940

FIGURE O-9: Portfolio 5 cumulative resource additions, capacity (MW)

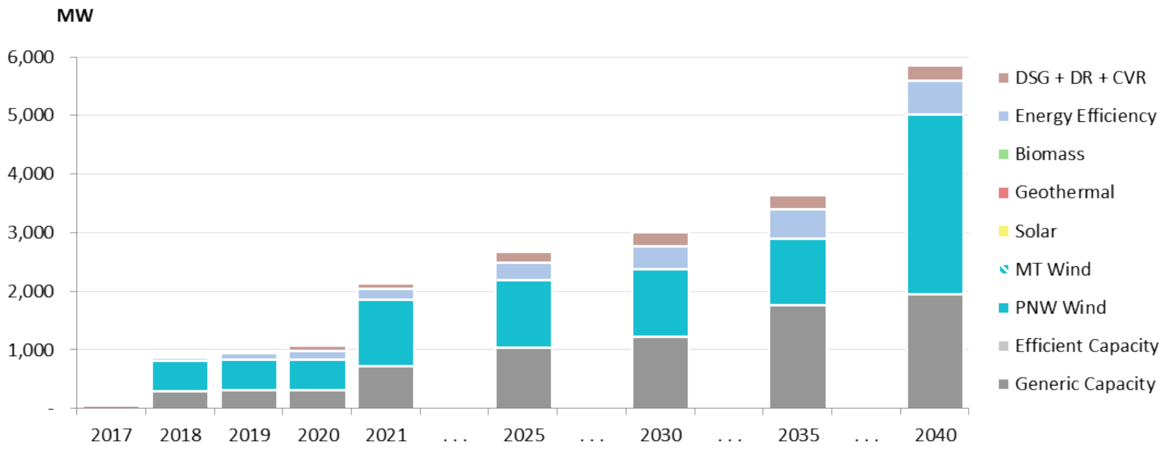
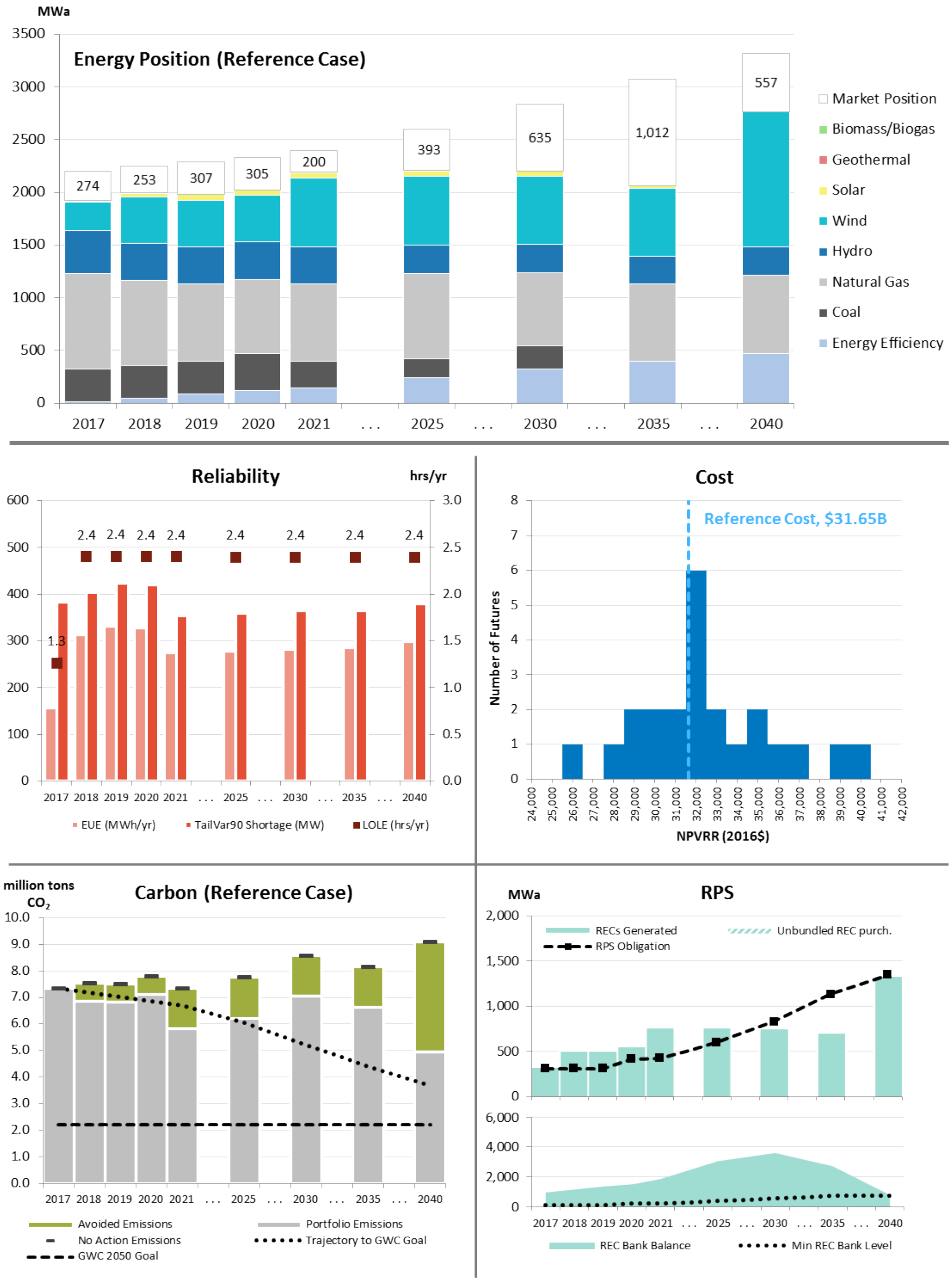


FIGURE O-10: Portfolio 5 output summary



Portfolio 6: Diverse Wind 2021

This portfolio is identical to *Portfolio 5 – Wind 2018*, but adds Montana Wind instead of PNW Wind in 2021, with the wind resources sized to add the same energy as those in *Portfolio 5*. Due to Montana Wind's capacity factor and capacity contribution, there is a requirement for less wind capacity and less generic capacity beginning in 2021. When compared with *Portfolio 5*, this portfolio allows PGE to estimate the costs and benefits of Montana Wind, including a Montana transmission infrastructure budget (if transmission were necessary to access a remote resource). Chapter 12, Modeling Results, provides the results of that comparison.

TABLE O-7: Portfolio 6 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		515		515		515		2,447
MT Wind	-	-	-	-	507		507		507		507		507
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	650		966		1,152		1,693		1,856

FIGURE O-11: Portfolio 6 cumulative resource additions, capacity (MW)

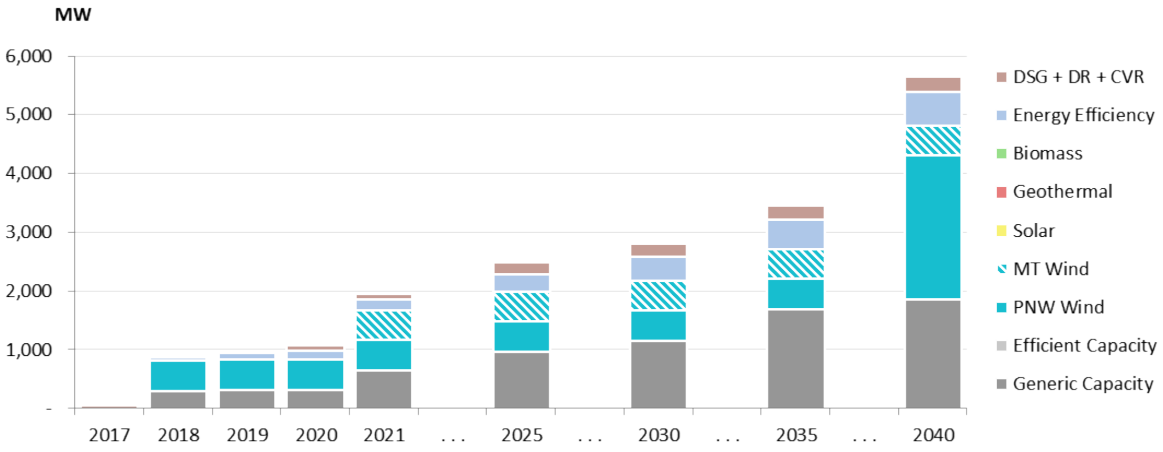
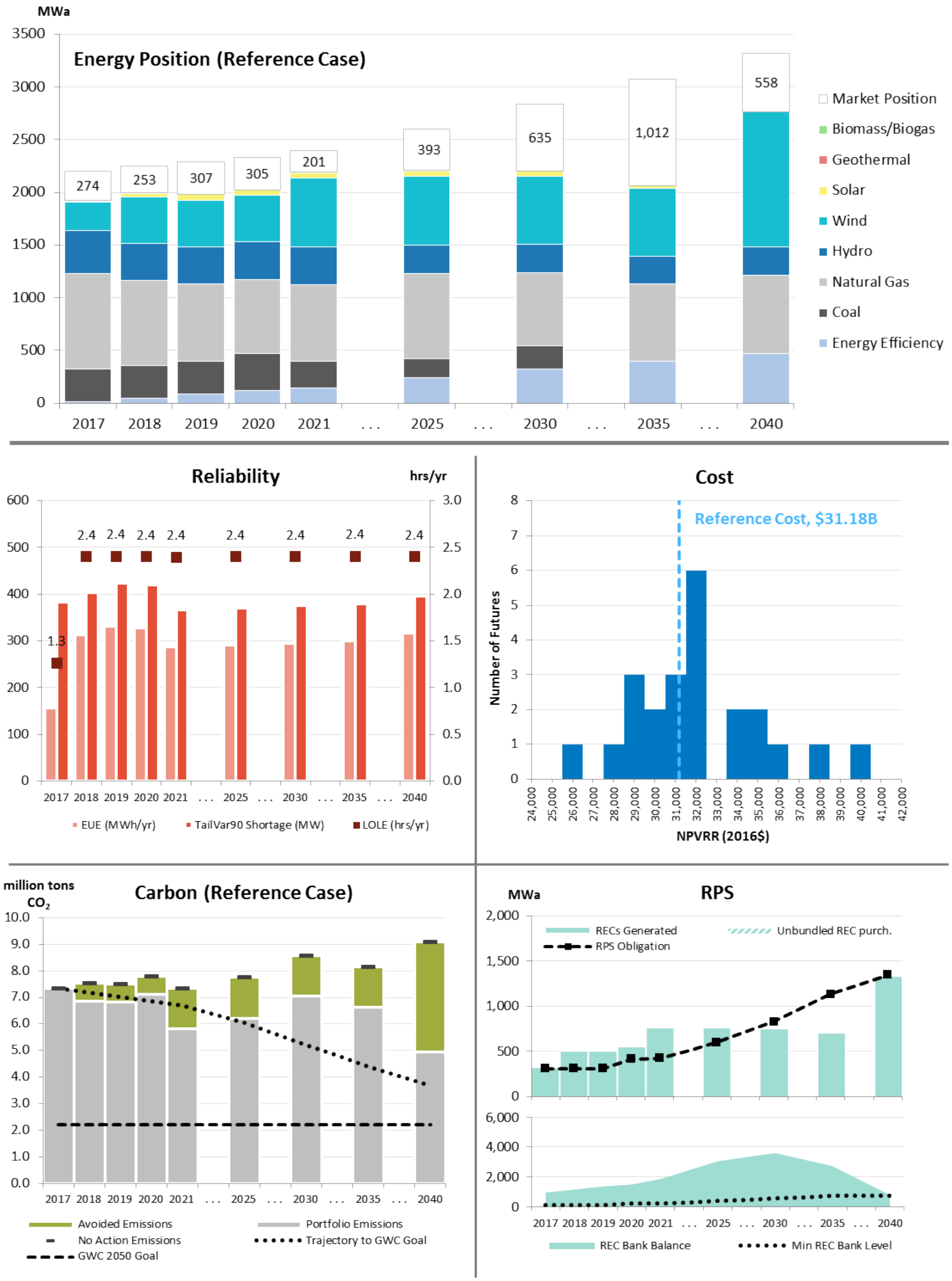


FIGURE O-12: Portfolio 6 output summary



Portfolio 7: Wind 2018 + Solar PV 2021

Including 50 MWa of Solar PV in 2021 in this portfolio allows PGE to explore the potential benefits of displacing a portion of the PNW Wind resource with Solar PV. Solar PV's increased capacity contribution allows this portfolio to require less generic capacity in 2021. The Solar PV resource, online January 1, 2021, qualifies for 26% ITC based on IRP modeling assumptions.

TABLE O-8: Portfolio 7 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	994		994		994		994		2,927
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	207		207		207		207		207
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	673		994		1,187		1,705		1,878

FIGURE O-13: Portfolio 7 cumulative resource additions, capacity (MW)

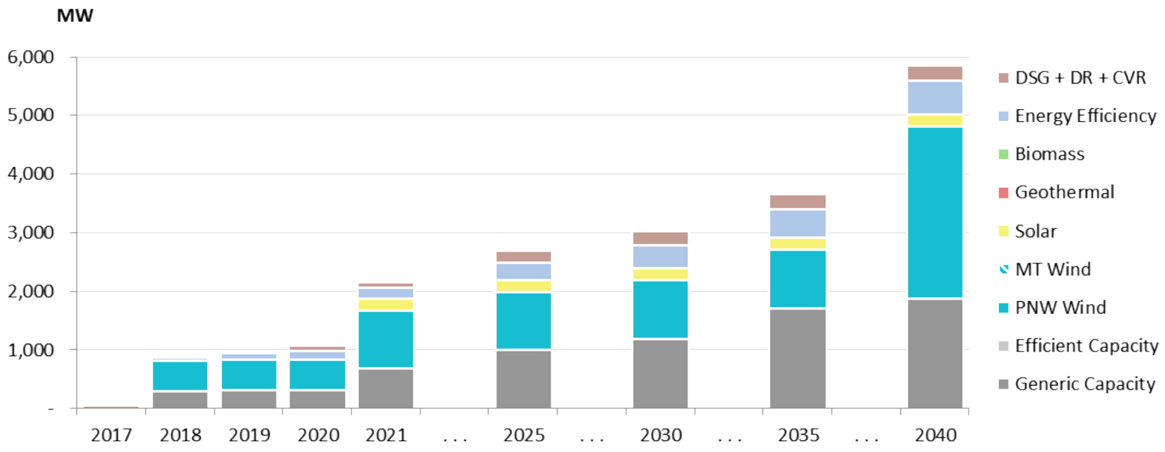
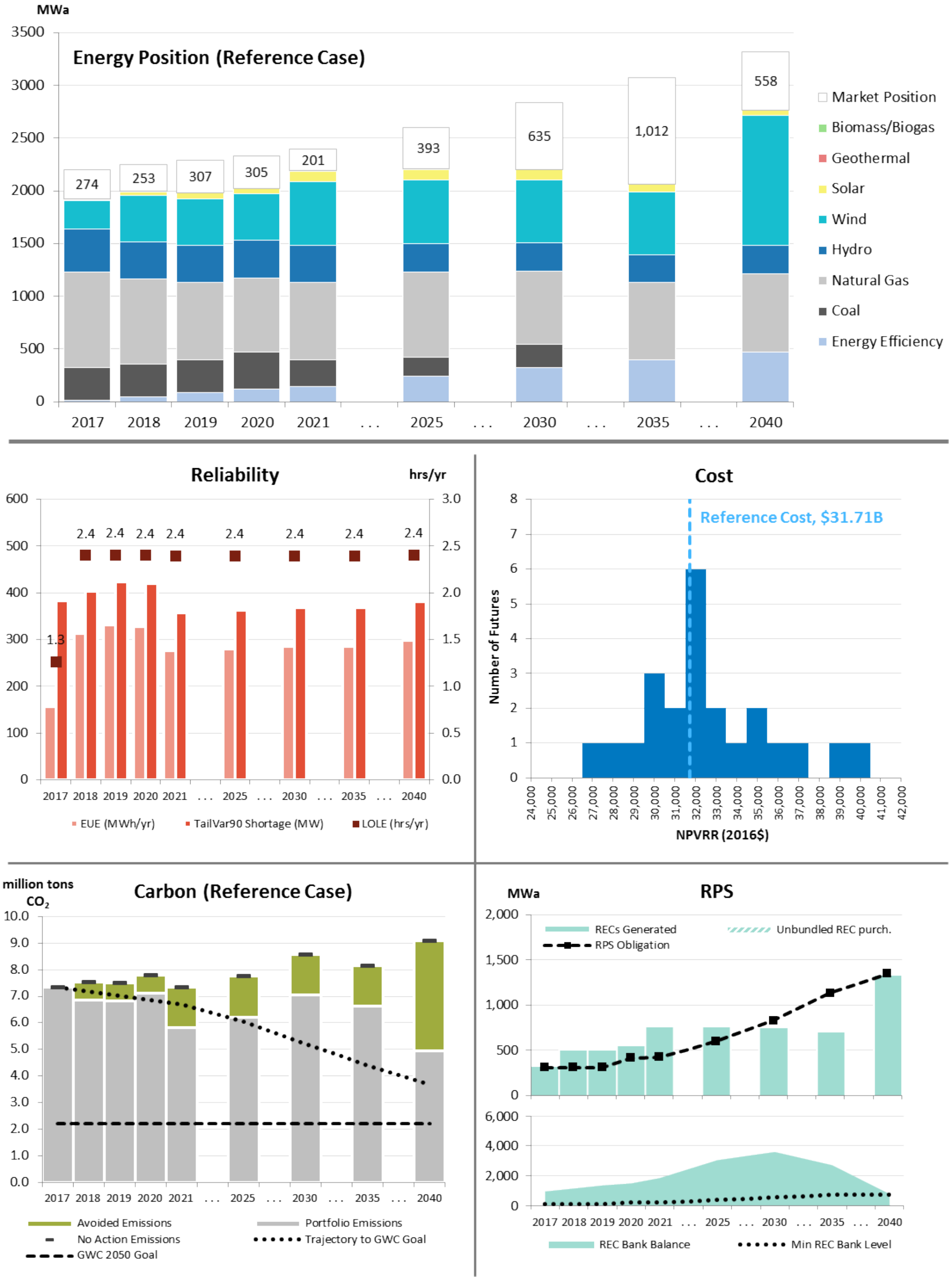


FIGURE O-14: Portfolio 7 output summary



Portfolio 8: Geothermal 2021

This portfolio adds a 30 MW geothermal resource in 2021, displacing 27 MWa of 2021 PNW Wind compared to *Portfolio 5 – Wind 2018*. Additionally, the geothermal resource reduces the quantity of generic capacity added in 2021. This portfolio provides PGE with a means to weigh the potential benefits of a non-variable renewable resource compared to PNW Wind.

TABLE O-9: Portfolio 8 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	1,063		1,063		1,063		1,063		2,996
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	30		30		30		30		30
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	693		1,012		1,203		1,734		1,914

FIGURE O-15: Portfolio 8 cumulative resource additions, capacity (MW)

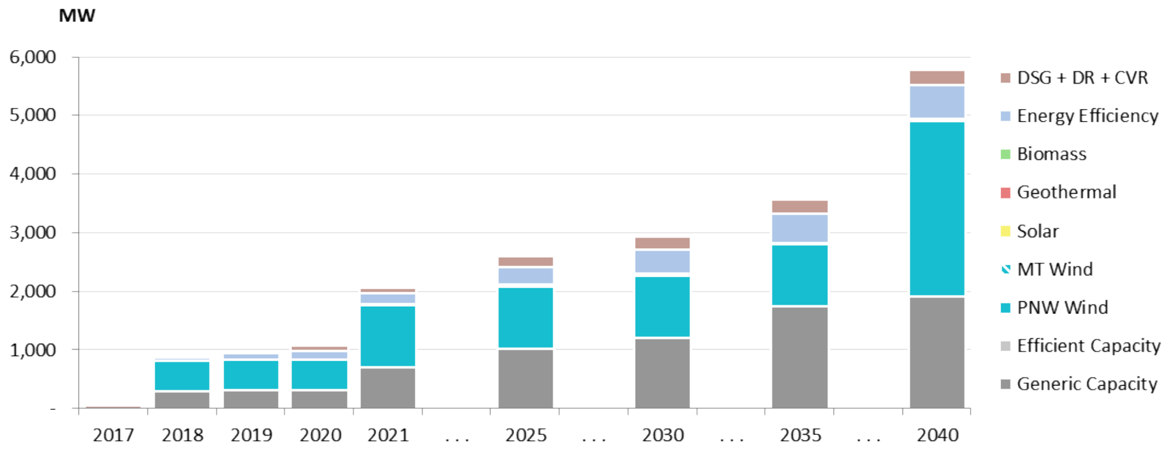
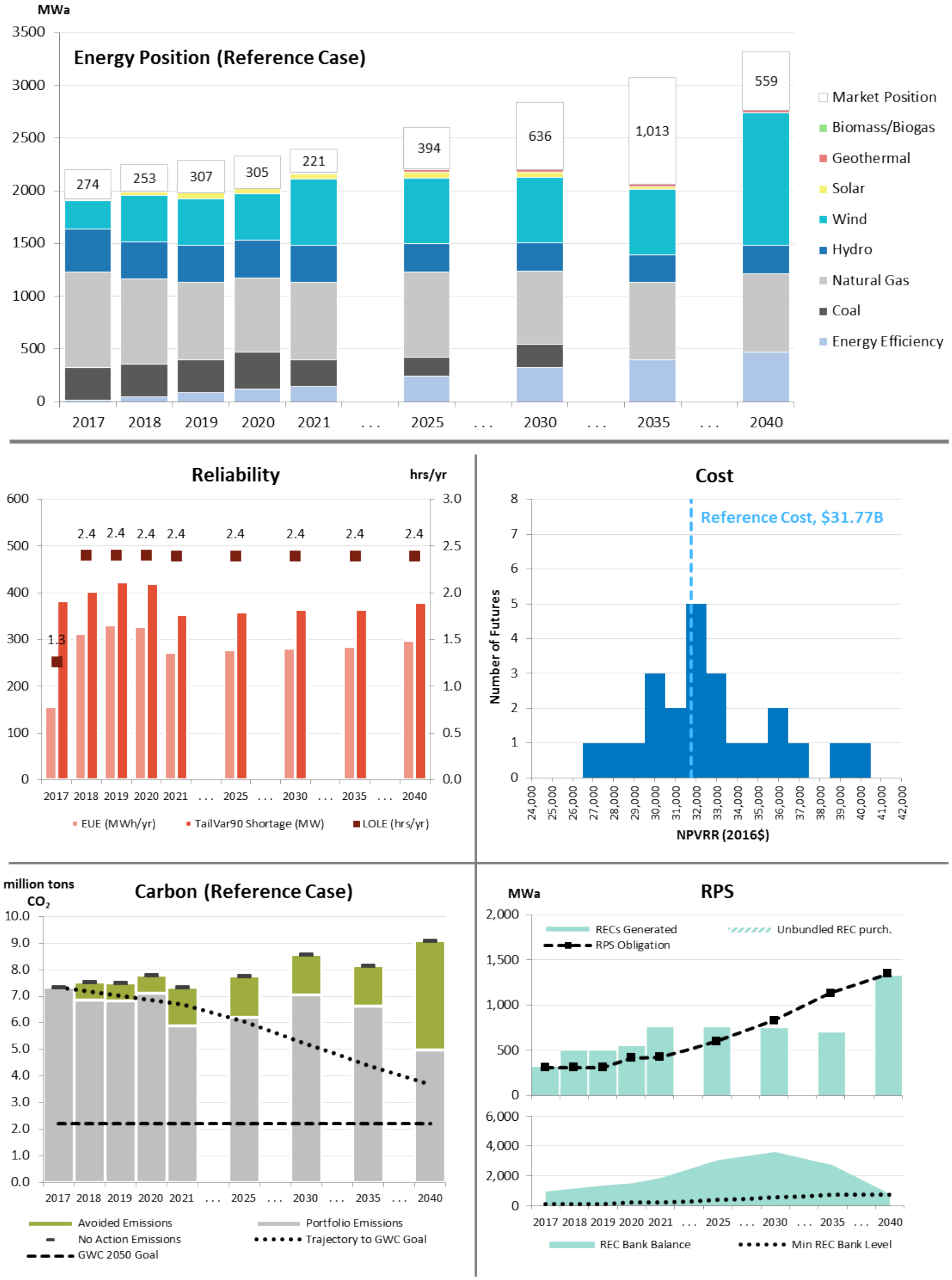


FIGURE O-16: Portfolio 8 output summary



Portfolio 9: Boardman Biomass 2021

The Boardman Biomass portfolio is constructed from *Portfolio 5 – Wind 2018*; however, in 2021, the portfolio includes the Boardman Biomass Project (570 MW) and does not include additions for PNW Wind or generic capacity. Additionally, generic capacity additions are avoided in 2022-2024 and reduced in 2025. This portfolio provides PGE with a means to weigh the potential benefits of a seasonal non-variable renewable resource compared to PNW Wind and further investigate the cost-effectiveness threshold for this project.

TABLE O-10: Portfolio 9 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		515		515		515		2,421
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	570		570		570		570		570
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	318		629		817		1,342		1,500

FIGURE O-17: Portfolio 9 cumulative resource additions, capacity (MW)

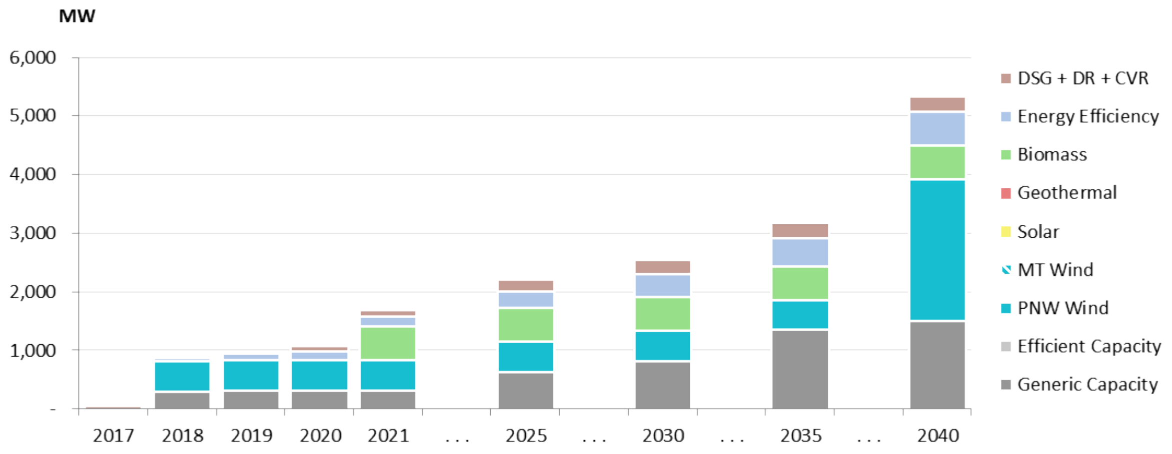
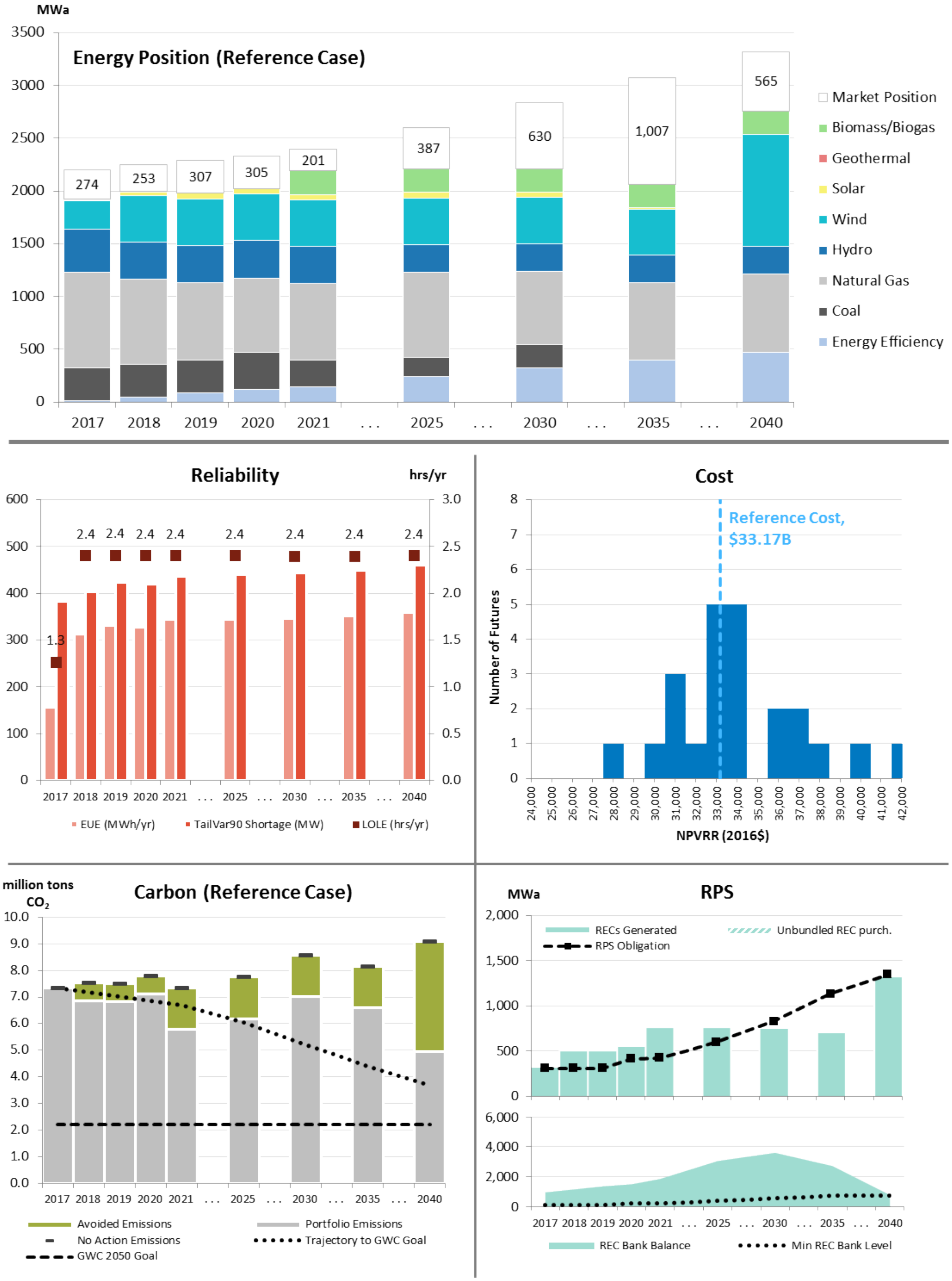


FIGURE O-18: Portfolio 9 output summary



Portfolio 10: Wind 2018 + Solar PV 2018

This portfolio is similar to *Portfolio 7 – Wind 2018 + Solar PV 2021*, but it displaces 50 MWa of the PNW Wind resource addition with Solar PV in 2018, rather than 2021. The slight timing change results in the inclusion of a Solar PV resource that receives the full 30% ITC, while displacing wind that qualifies for 100% PTC. PGE adjusts the generic capacity additions to reflect the earlier addition of Solar PV.

TABLE O-11: Portfolio 10 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	…	2025	…	2030	…	2035	…	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	368	368	368	994		994		994		994		2,927
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	207	207	207	207		207		207		207		207
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	240	275	275	673		994		1,187		1,705		1,878

FIGURE O-19: Portfolio 10 cumulative resource additions, capacity (MW)

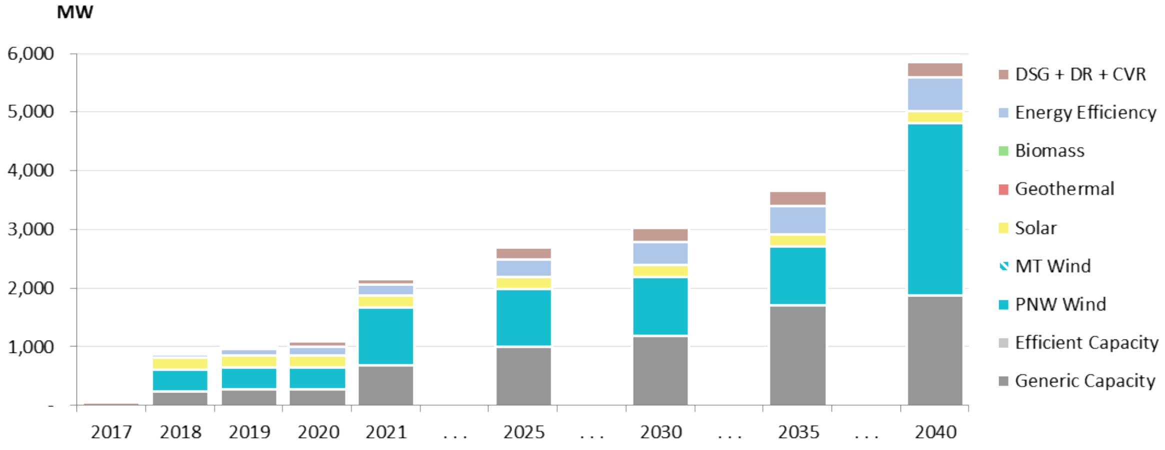
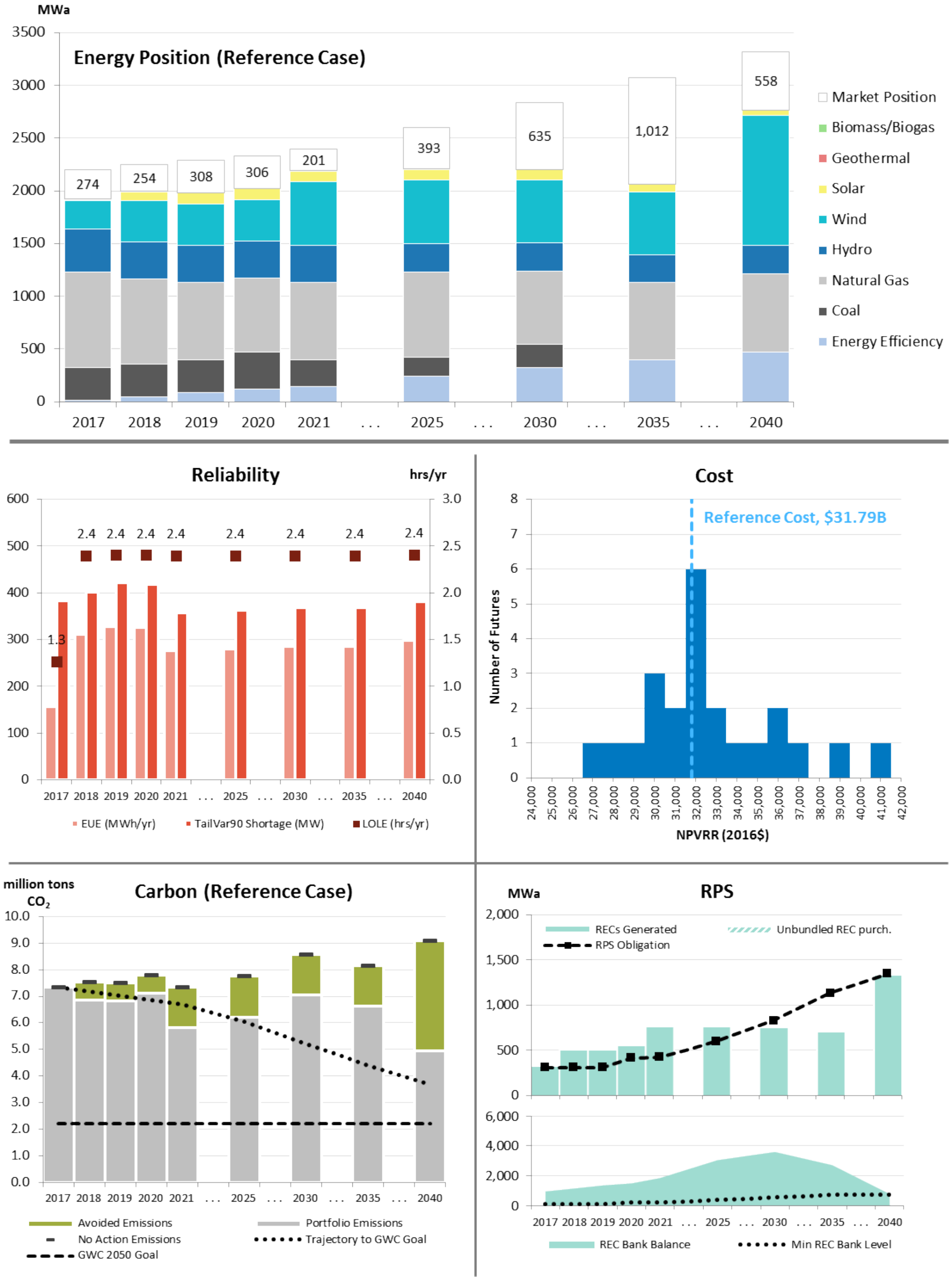


FIGURE O-20: Portfolio 10 output summary



Portfolio 11: Efficient Capacity 2021 + High EE

This portfolio is similar to *Portfolio 3 – Efficient Capacity 2021*, except for procuring additional EE to the Energy Trust's All Achievable EE forecast. Including All Achievable EE displaces portions of the energy, capacity, and RPS requirements in the portfolio. All Achievable EE is discussed in Section 6.1, *Energy Efficiency*.

TABLE O-12: Portfolio 11 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	26	97	163	221	270		420		552		655		753
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	432	432	432	432		546		633		2,298		2,819
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	389		389		389		389		389
Generic Capacity	-	251	258	258	298		577		735		1,154		1,391

FIGURE O-21: Portfolio 11 cumulative resource additions, capacity (MW)

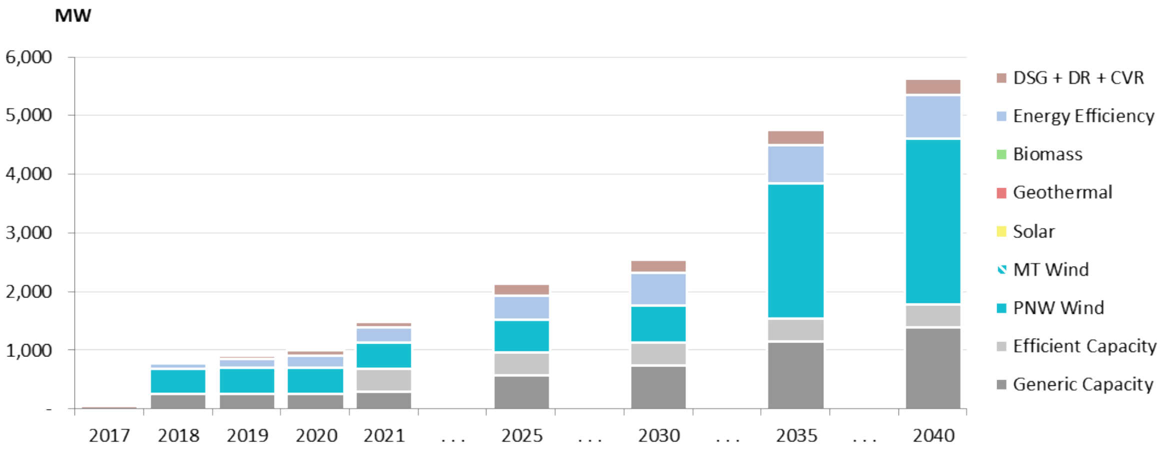
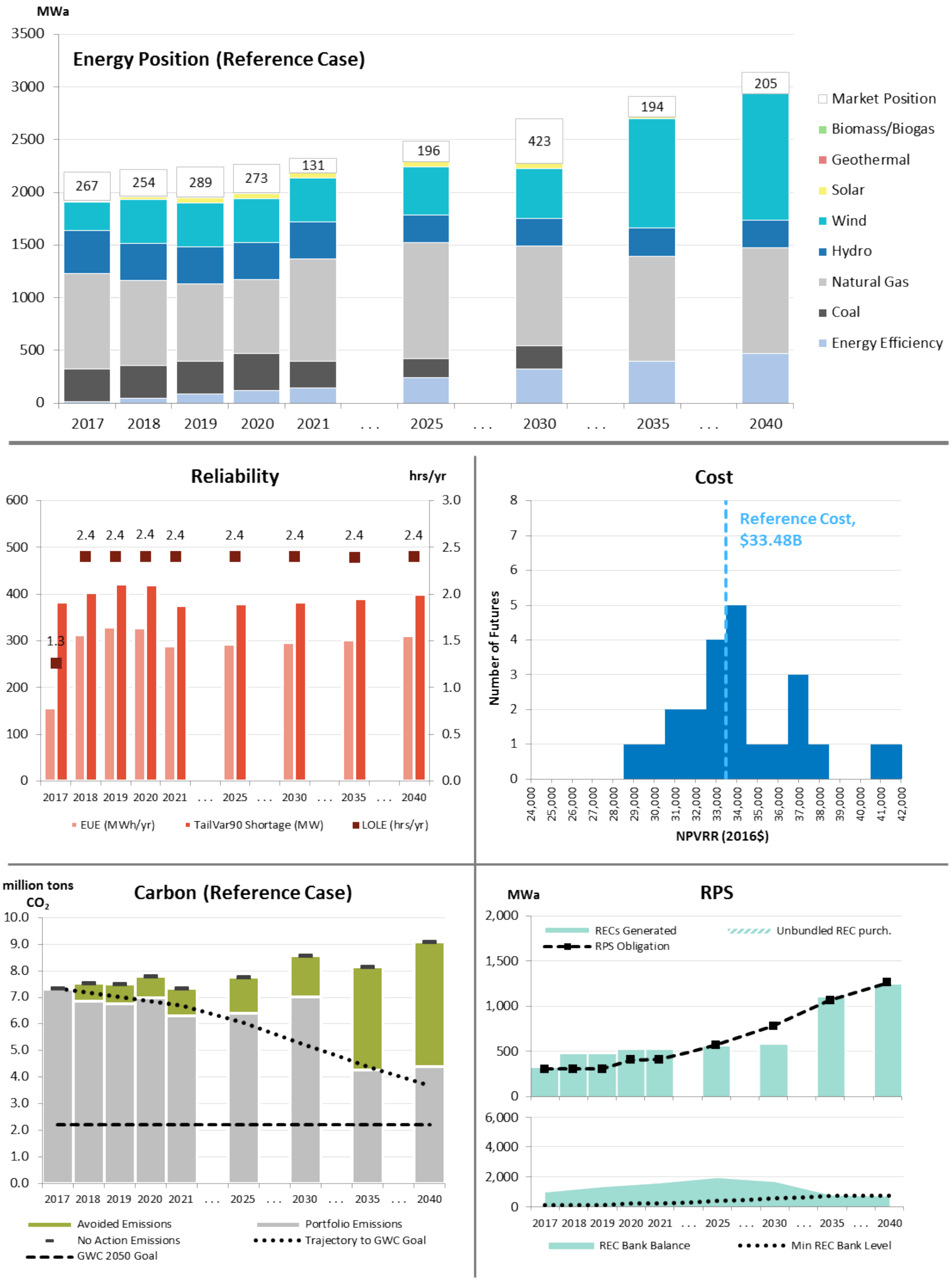


FIGURE O-22: Portfolio 11 output summary



Portfolio 12: Wind 2018 + High EE

This portfolio is similar to *Portfolio 5 – Wind 2018*, except for procuring additional EE to the Energy Trust's All Achievable EE forecast. Including All Achievable EE displaces portions of the energy, capacity, and RPS requirements in the portfolio.

TABLE O-13: Portfolio 12 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	…	2025	…	2030	…	2035	…	2040
Energy Efficiency	26	97	163	221	270		420		552		655		753
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	432	432	432	923		923		923		1,237		2,819
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	251	258	258	636		925		1,091		1,586		1,769

FIGURE O-23: Portfolio 12 cumulative resource additions, capacity (MW)

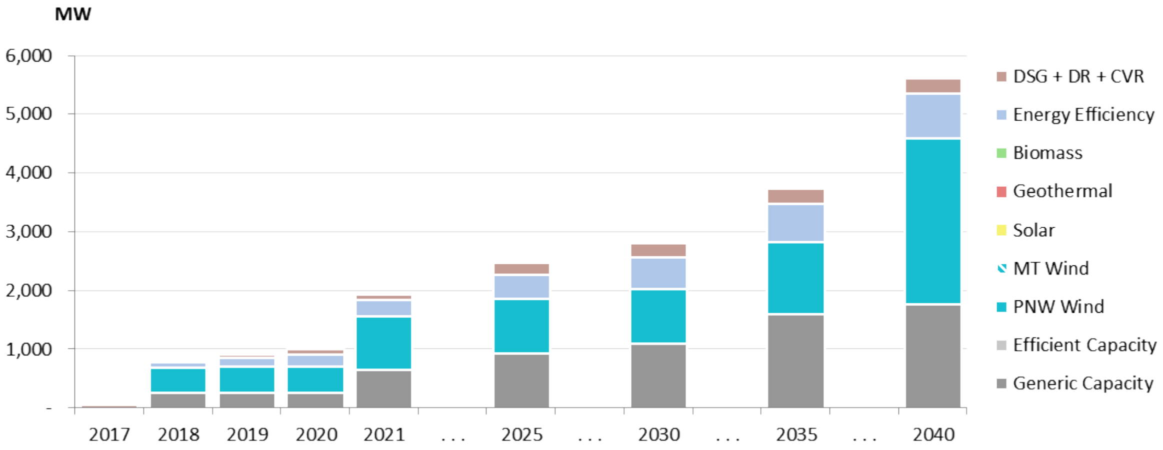
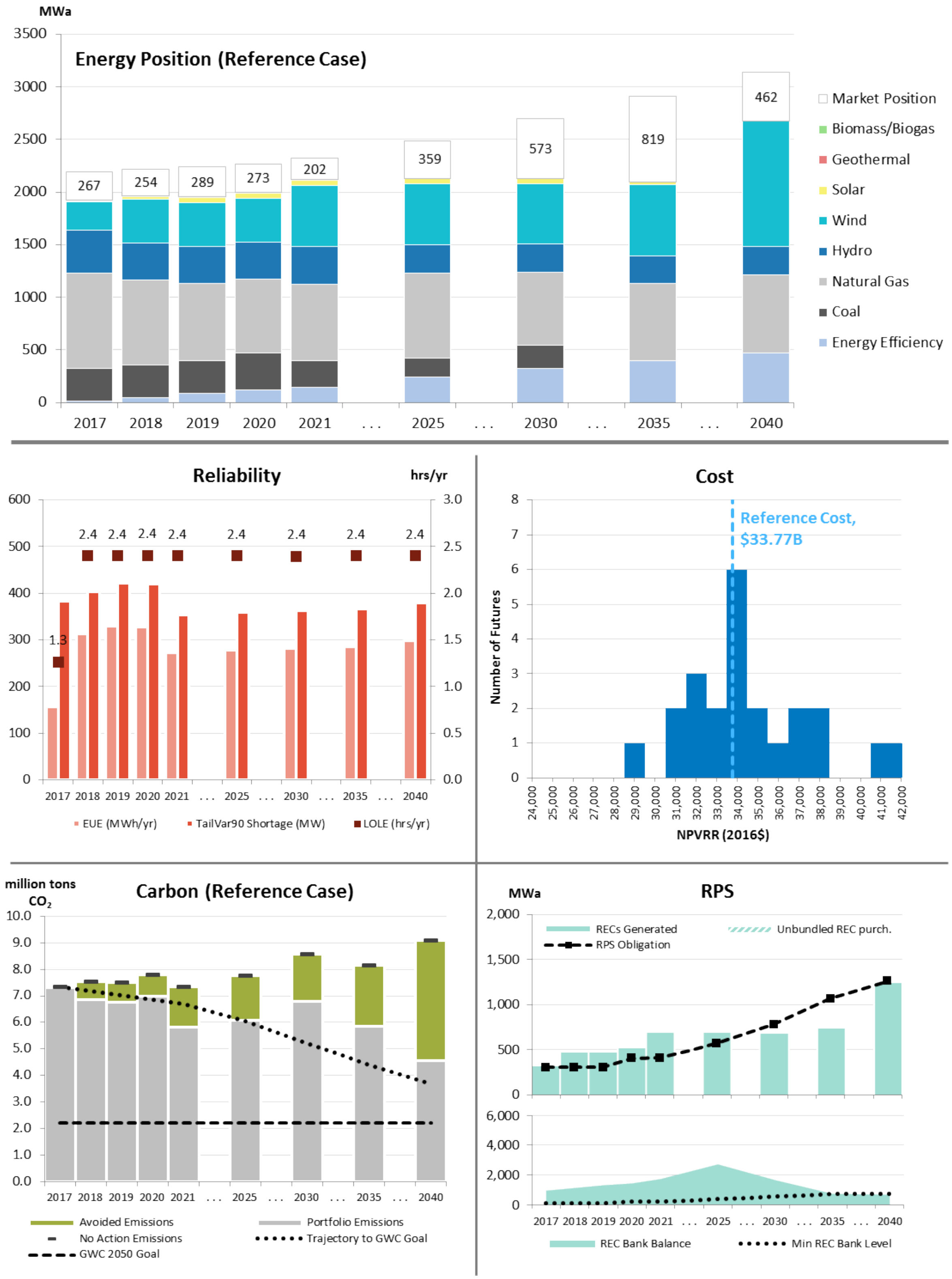


FIGURE O-24: Portfolio 12 output summary



Portfolio 13: Colstrip Wind 2030

This portfolio uses *Portfolio 2 – RPS Wind 2018* as a basis, removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2029, and replaces them on an equivalent expected energy basis with the Montana Wind resource discussed previously. Generic capacity is also included to achieve resource adequacy.

TABLE O-14: Portfolio 13 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		628		1,033		2,271
MT Wind	-	-	-	-	-		-		650		650		650
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	760		1,072		1,408		1,637		1,848

FIGURE O-25: Portfolio 13 cumulative resource additions, capacity (MW)

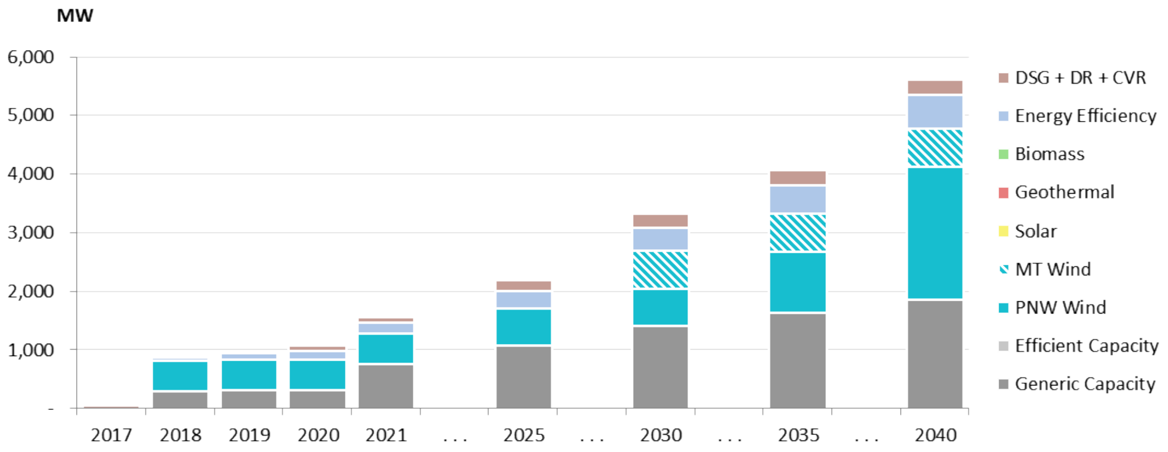
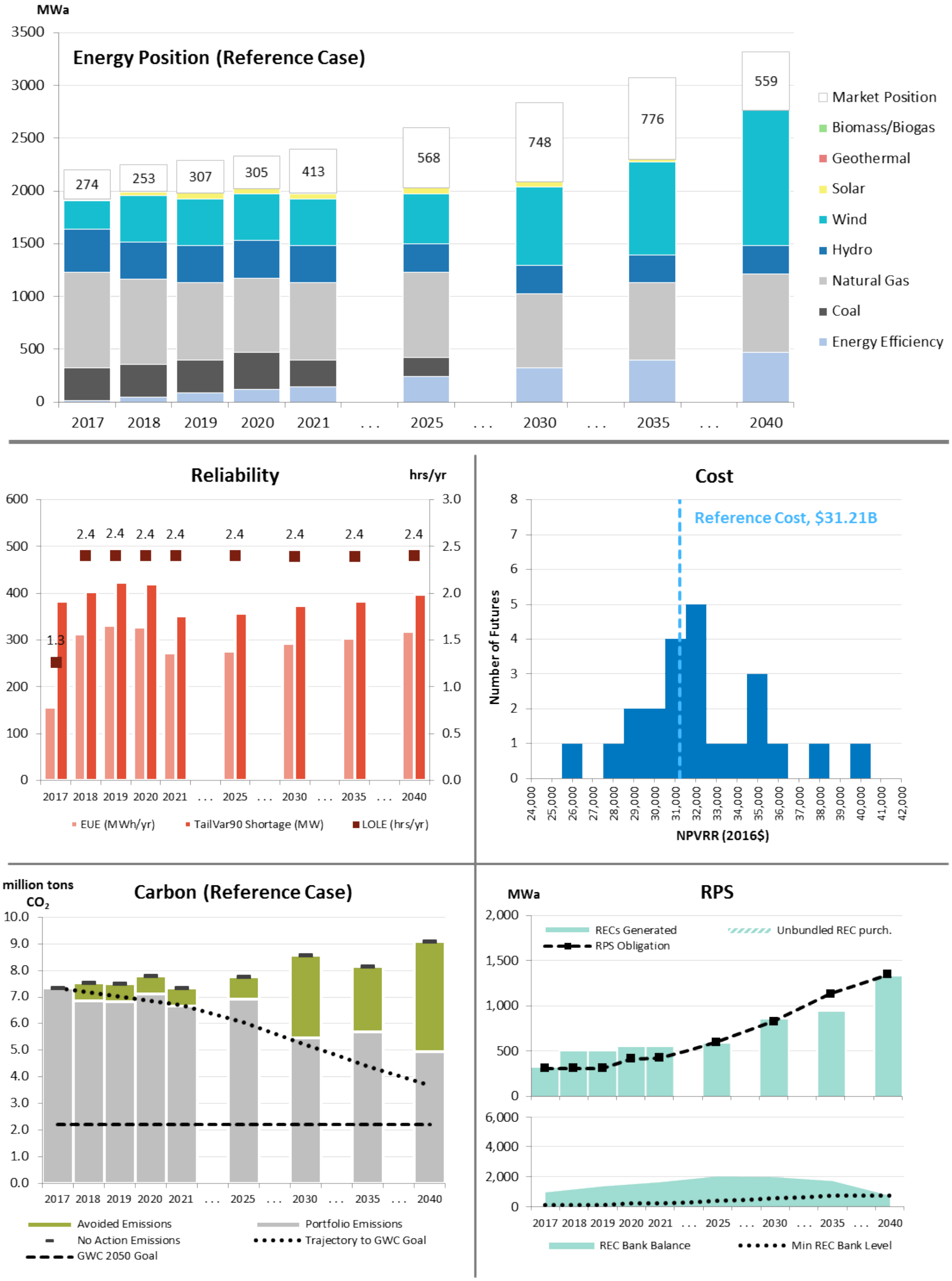


FIGURE O-26: Portfolio 13 output summary



Portfolio 14: Colstrip Wind 2035

Portfolio 14 serves as a comparison with *Portfolio 13 – Colstrip Wind 2030*. The portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2034 and replaces them, on an equivalent expected energy basis, with Montana Wind. Generic capacity is included to achieve resource adequacy. Together, *Portfolio 13* and *Portfolio 14* aim to inform the relative costs/benefits of a relatively earlier or later date for removal of Colstrip Units 3 & 4 from PGE's resource portfolio when considering remote wind as the replacement resource.

TABLE O-15: Portfolio 14 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		1,708		2,271
MT Wind	-	-	-	-	-		-		-		650		650
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	290	318	318	760		1,072		1,253		1,594		1,848

FIGURE O-27: Portfolio 14 cumulative resource additions, capacity (MW)

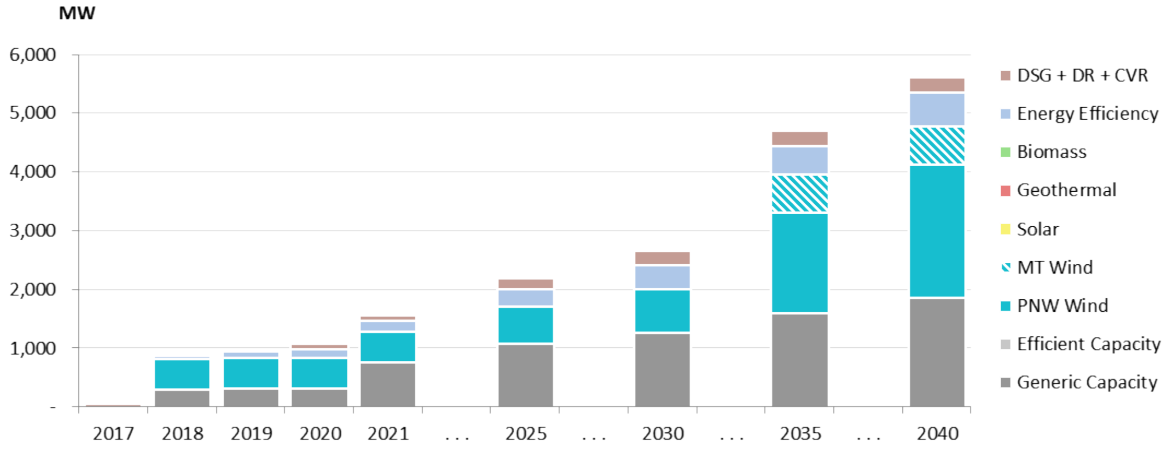
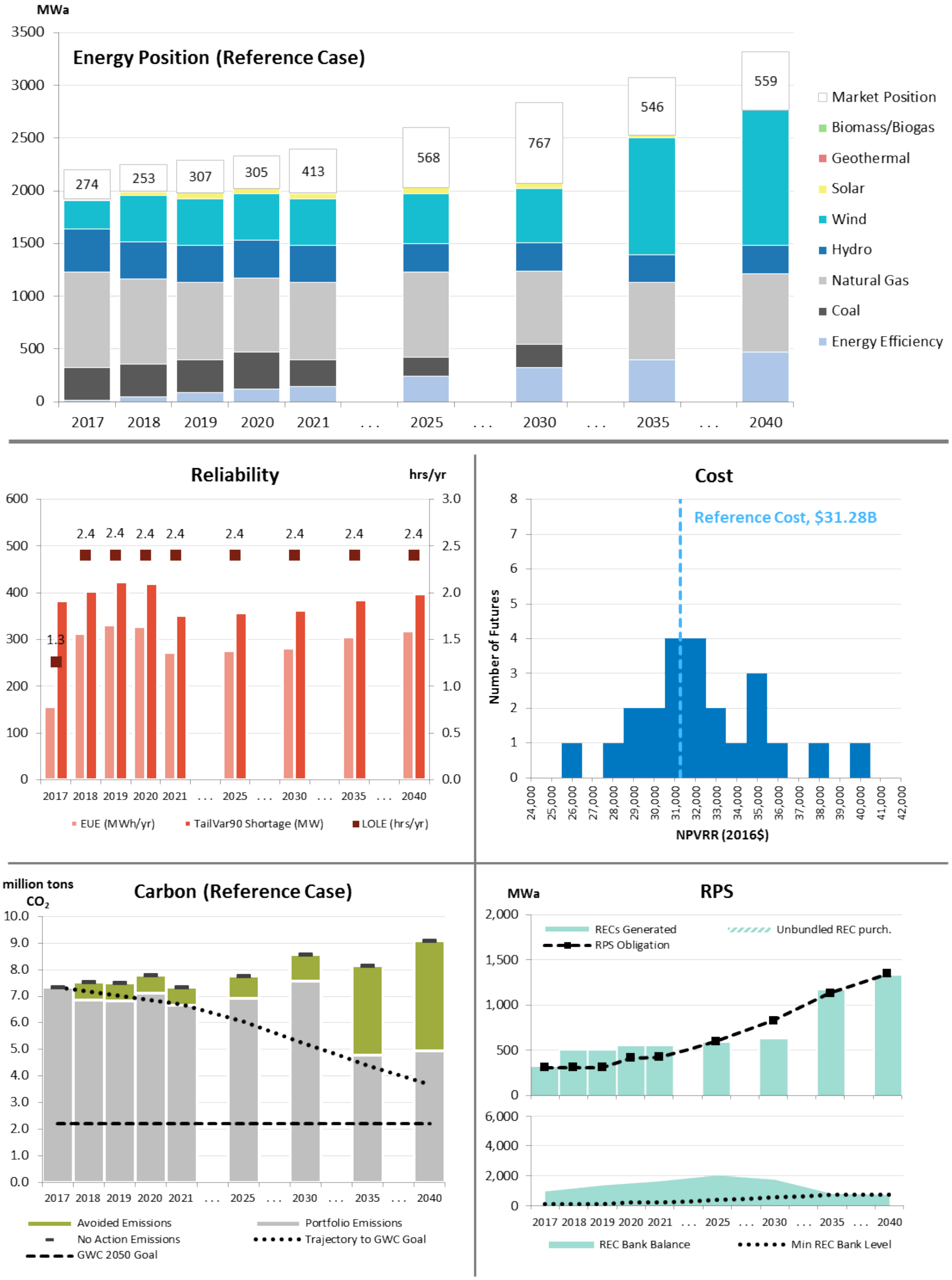


FIGURE O-28: Portfolio 14 output summary



Portfolio 15: Colstrip Efficient Capacity 2030

Similar to *Portfolio 13 – Colstrip Wind 2030*, this portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2029, but replaces them with an H-class CCCT rather than a wind resource. The portfolio also adds generic capacity resources as needed to achieve resource adequacy. Using *Portfolio 13* as the comparator provides insights regarding the potential relative costs/benefits of a CCCT as the replacement resource versus remote wind after accounting for timing effects.

TABLE O-16: Portfolio 15 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		389		389		389
Generic Capacity	-	290	318	318	760		1,072		1,220		1,362		1,563

FIGURE O-29: Portfolio 15 cumulative resource additions, capacity (MW)

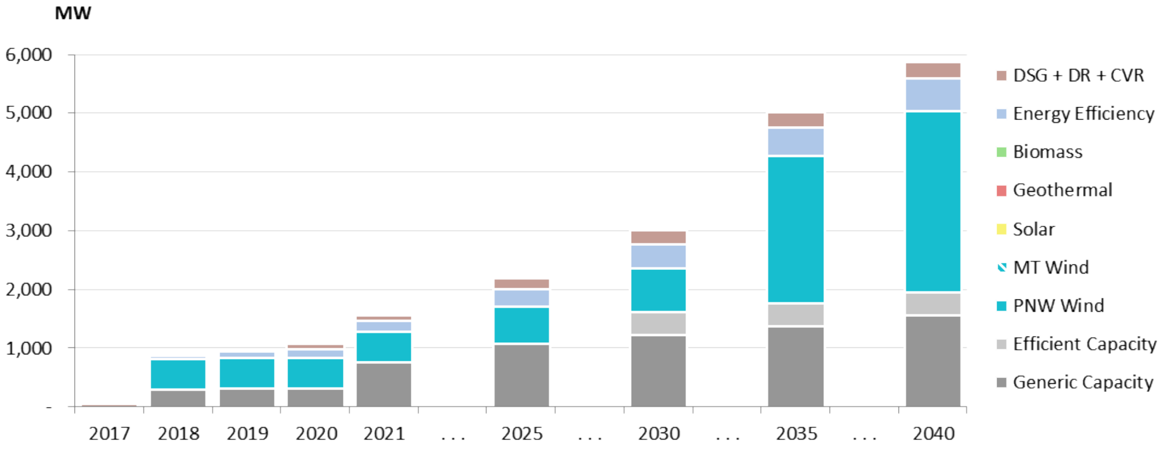
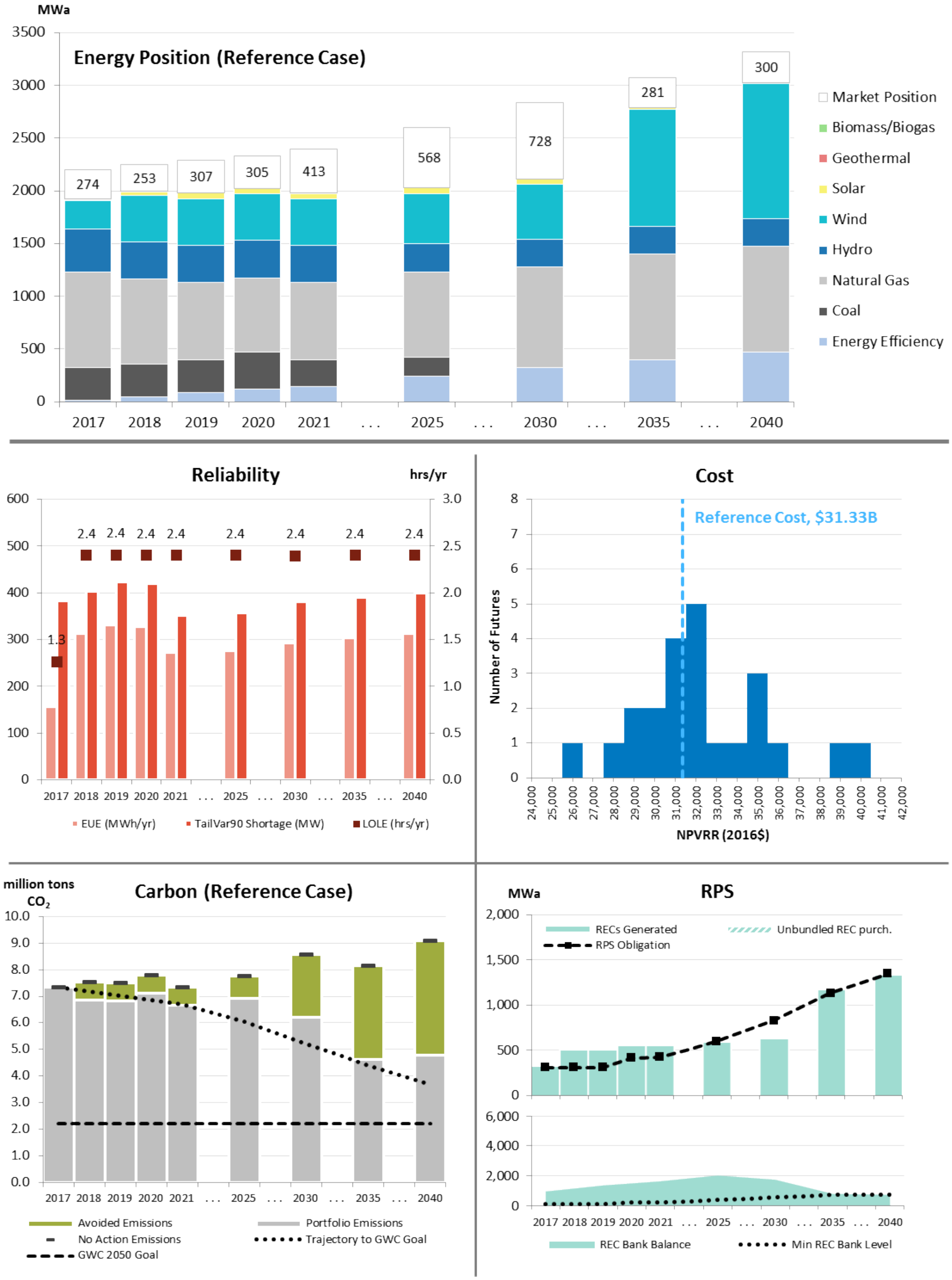


FIGURE O-30: Portfolio 15 output summary



Portfolio 16: Colstrip Efficient Capacity 2035

This portfolio provides a comparison with *Portfolio 14 – Colstrip Wind 2035* and *Portfolio 15 – Colstrip Efficient Capacity 2030*. The portfolio removes Colstrip Units 3 & 4 from PGE's resource portfolio at year-end 2034, and replaces them with an H-class CCCT rather than a wind resource. PGE also adjusts the generic capacity additions to achieve resource adequacy. Together, *Portfolio 15* and *Portfolio 16* aim to inform the relative costs/benefits of a relatively earlier or later date for removal of Colstrip Units 3 & 4 from PGE's resource portfolio when considering remote wind as the replacement resource. When compared with *Portfolio 14*, PGE again learns about the potential relative costs/benefits of a CCCT as the replacement resource versus remote wind after accounting for timing effects.

TABLE O-17: Portfolio 16 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	515	515	515	515		628		755		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		389		389
Generic Capacity	-	290	318	318	760		1,072		1,253		1,457		1,563

FIGURE O-31: Portfolio 16 cumulative resource additions, capacity (MW)

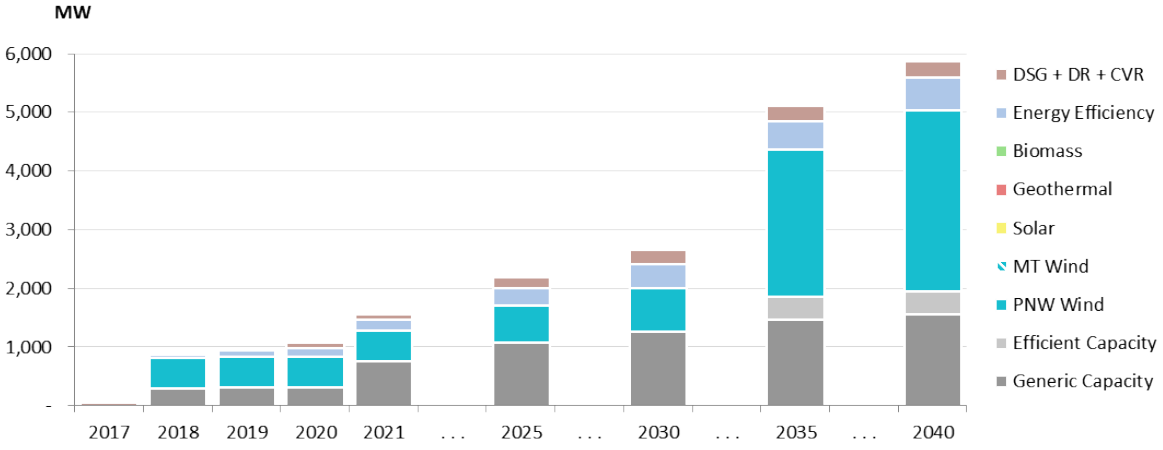
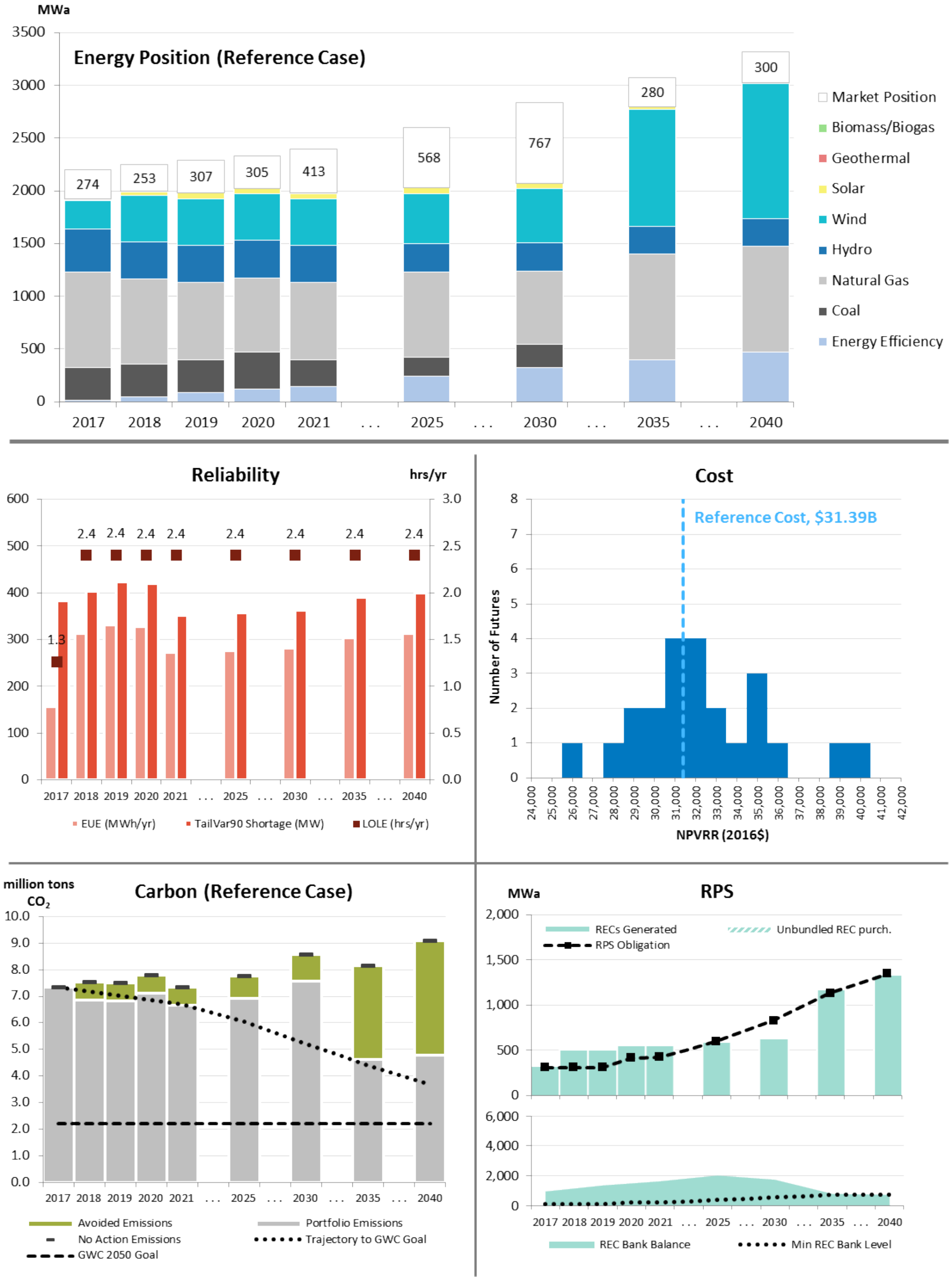


FIGURE O-32: Portfolio 16 output summary



Portfolio 17: RPS Wind 2020

This portfolio adopts a strategy of complying with long-term RPS qualifying resources in size and timing consistent with the respective RPS stair-steps, adding PNW Wind as follows: 31 MWa in 2020, 183 MWa in 2025, 258 MWa in 2030, and 383 MWa in 2035, 191 MWa in 2040, and 92 and 102 MWa in 2045 and 2050, respectively. Generic capacity additions are included as needed to achieve resource adequacy in each year.

TABLE O-18: Portfolio 17 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	-	-	90	90		628		1,386		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	352	379	379	804		1,072		1,220		1,688		1,940

FIGURE O-33: Portfolio 17 cumulative resource additions, capacity (MW)

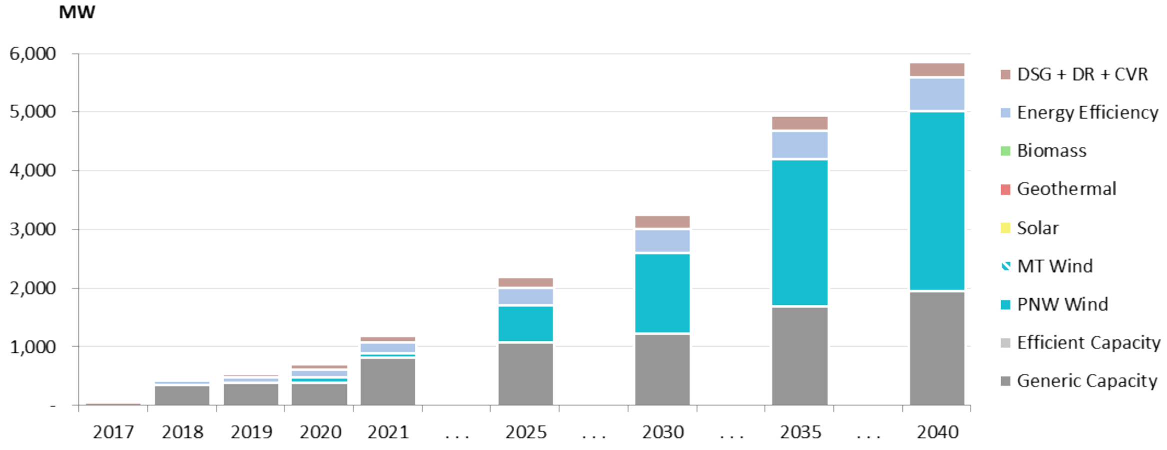
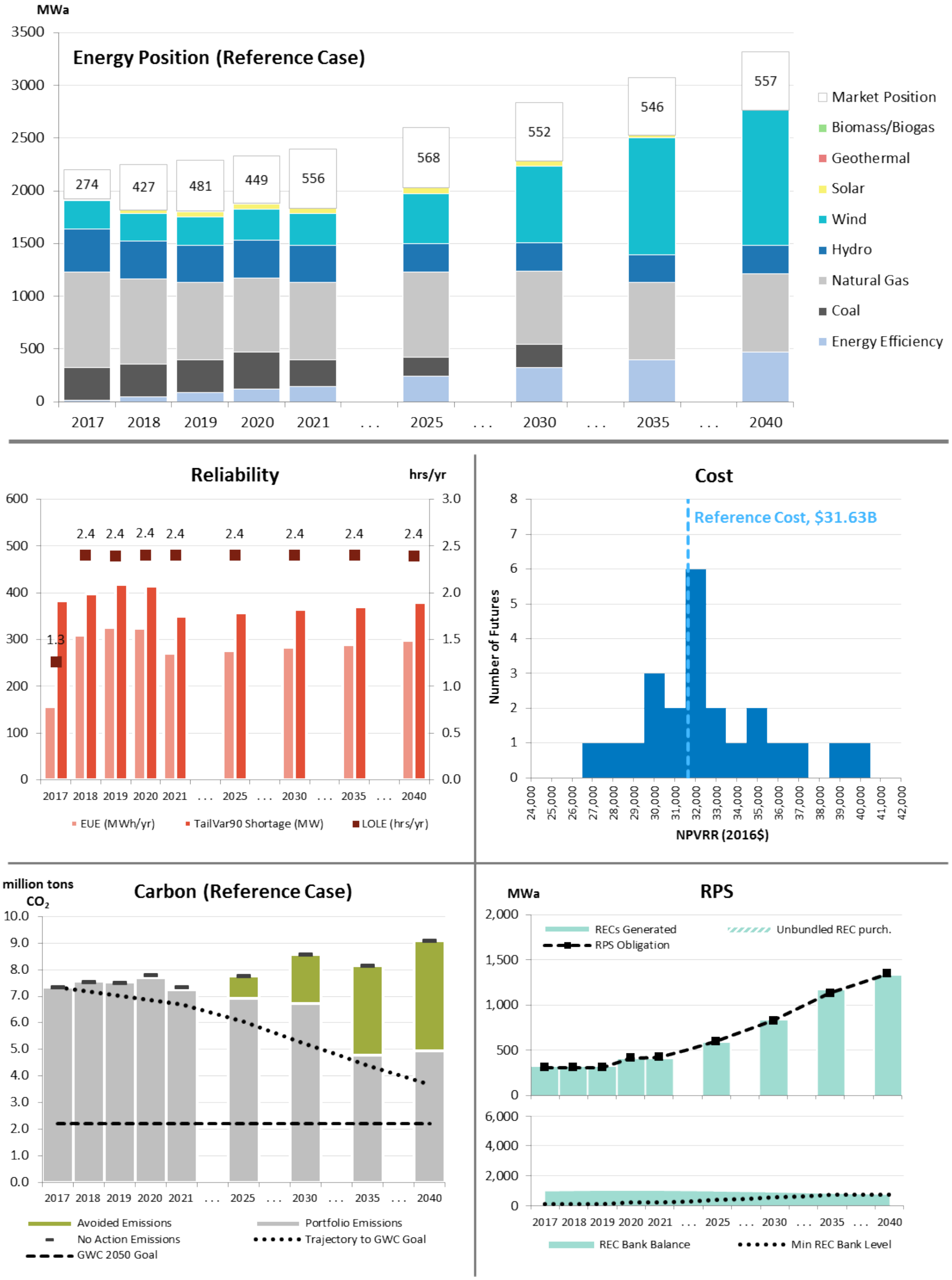


FIGURE O-34: Portfolio 17 output summary



Portfolio 18: RPS Wind 2025

This portfolio tests a strategy of deferring RPS long-term qualifying resource additions. In lieu of 2018 or 2020 resource actions, the first incremental RPS qualifying resource addition in this portfolio is a 213 MWa PNW Wind resource in 2025. Through 2035, this portfolio adds PNW Wind as follows: 213 MWa in 2025, 288 MWa in 2030, and 352 MWa in 2035. Additions post-2035 are identical to *Portfolio 17 – RPS Wind 2020*. Generic capacity additions are included as needed to achieve resource adequacy in each year. Relative to PGE's baseline assumption or the compliance stair-step assumption described in *Portfolio 17*, PGE expects this portfolio to receive a benefit on an NPV basis arising from the deferral of expenditure. However, deferring RPS action to 2025 accelerates resource additions on the back-end of the modeling time horizon in order to bring the REC bank to a position comparable to other strategies.

TABLE O-19: Portfolio 18 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	-	-	-	-		628		1,476		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	352	379	379	819		1,072		1,220		1,688		1,940

FIGURE O-35: Portfolio 18 cumulative resource additions, capacity (MW)

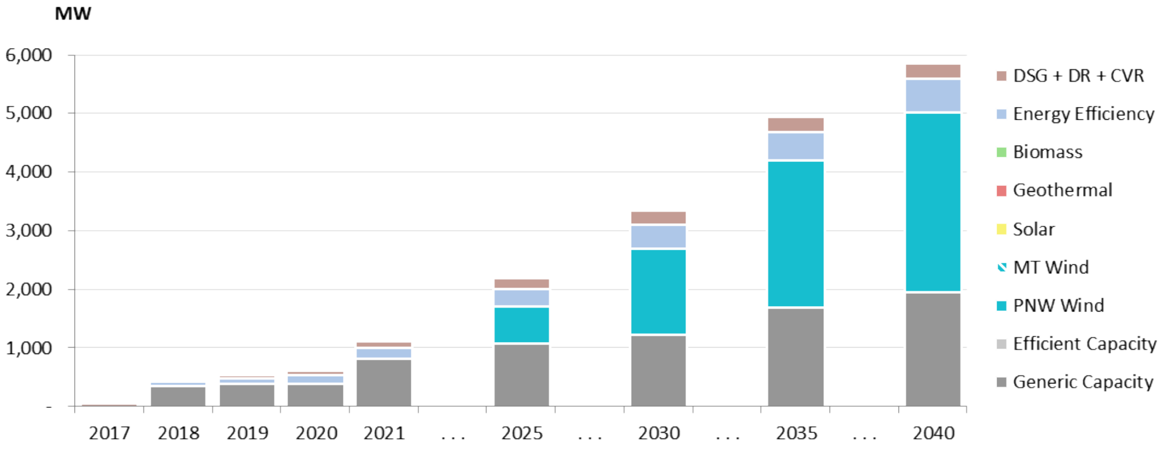
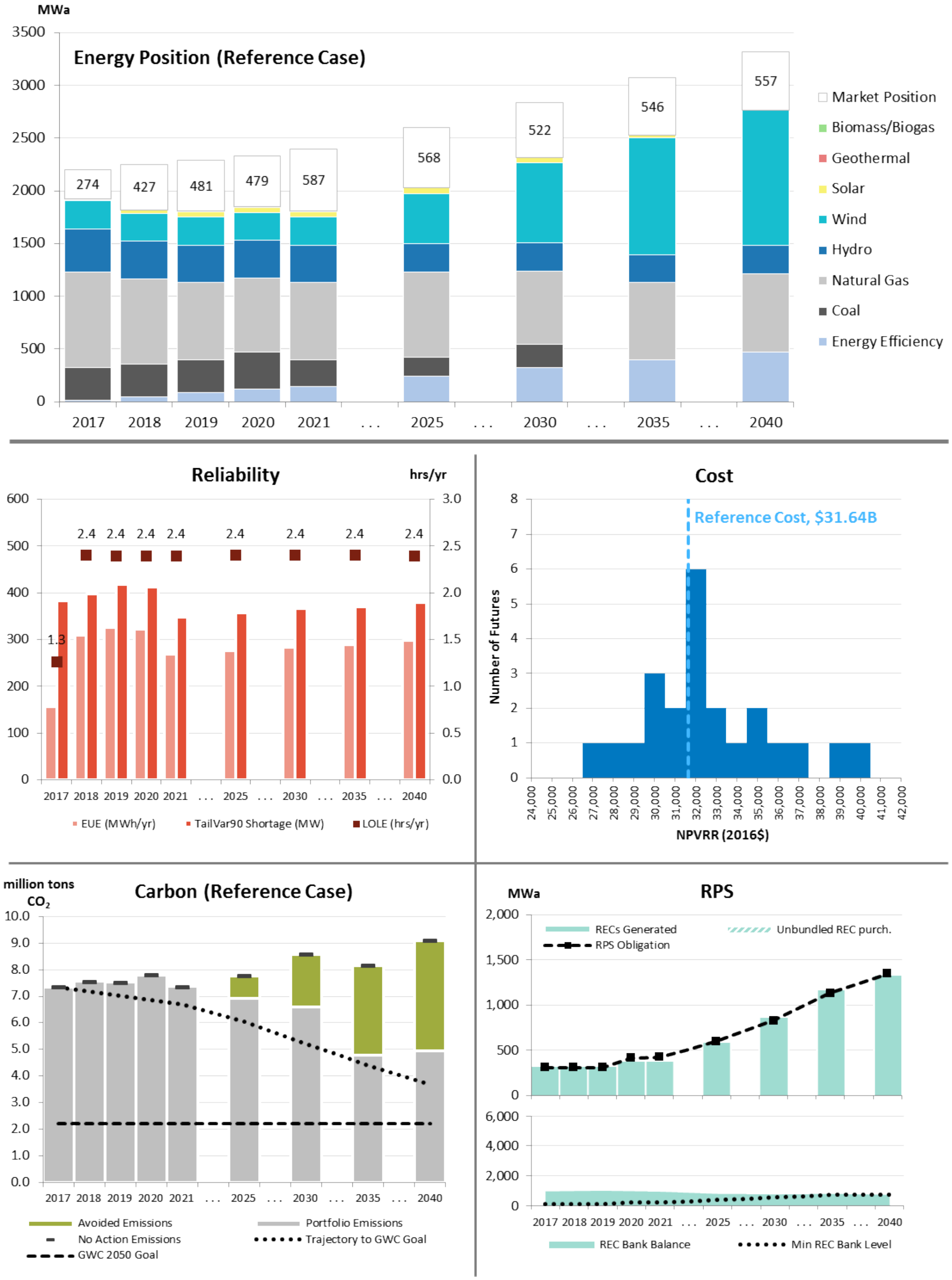


FIGURE O-36: Portfolio 18 output summary



Portfolio 19: RPS Wind 2021

Similar to *Portfolio 18 – RPS Wind 2025* in terms of the size of the first incremental RPS qualifying resource addition, this portfolio adds 213 MWa of PNW Wind in a single year. In this portfolio, however, the addition occurs in 2021, allowing the assumed wind resource to qualify for the final tranche of PTC benefit at the 40% level based on IRP modeling assumptions. Generic capacity additions are included as needed to achieve resource adequacy in each year. Relative to *Portfolio 18*, the earlier resource addition here results in an ability to defer resource additions to 2035 while maintaining a comparable REC bank position.

TABLE O-20: Portfolio 19 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	-	-	-	628		628		974		2,511		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	-		-		-		-		-
Generic Capacity	-	352	379	379	752		1,072		1,238		1,688		1,940

FIGURE O-37: Portfolio 19 cumulative resource additions, capacity (MW)

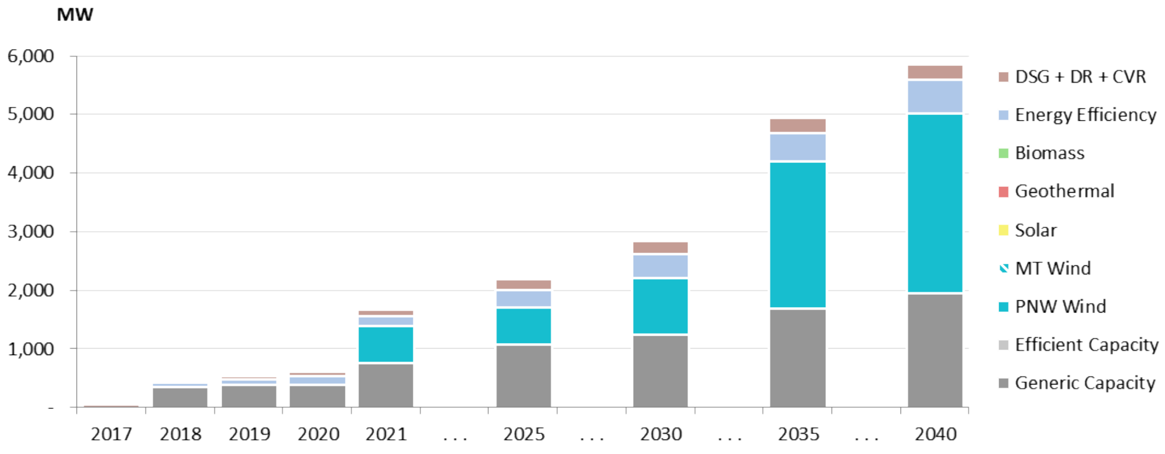
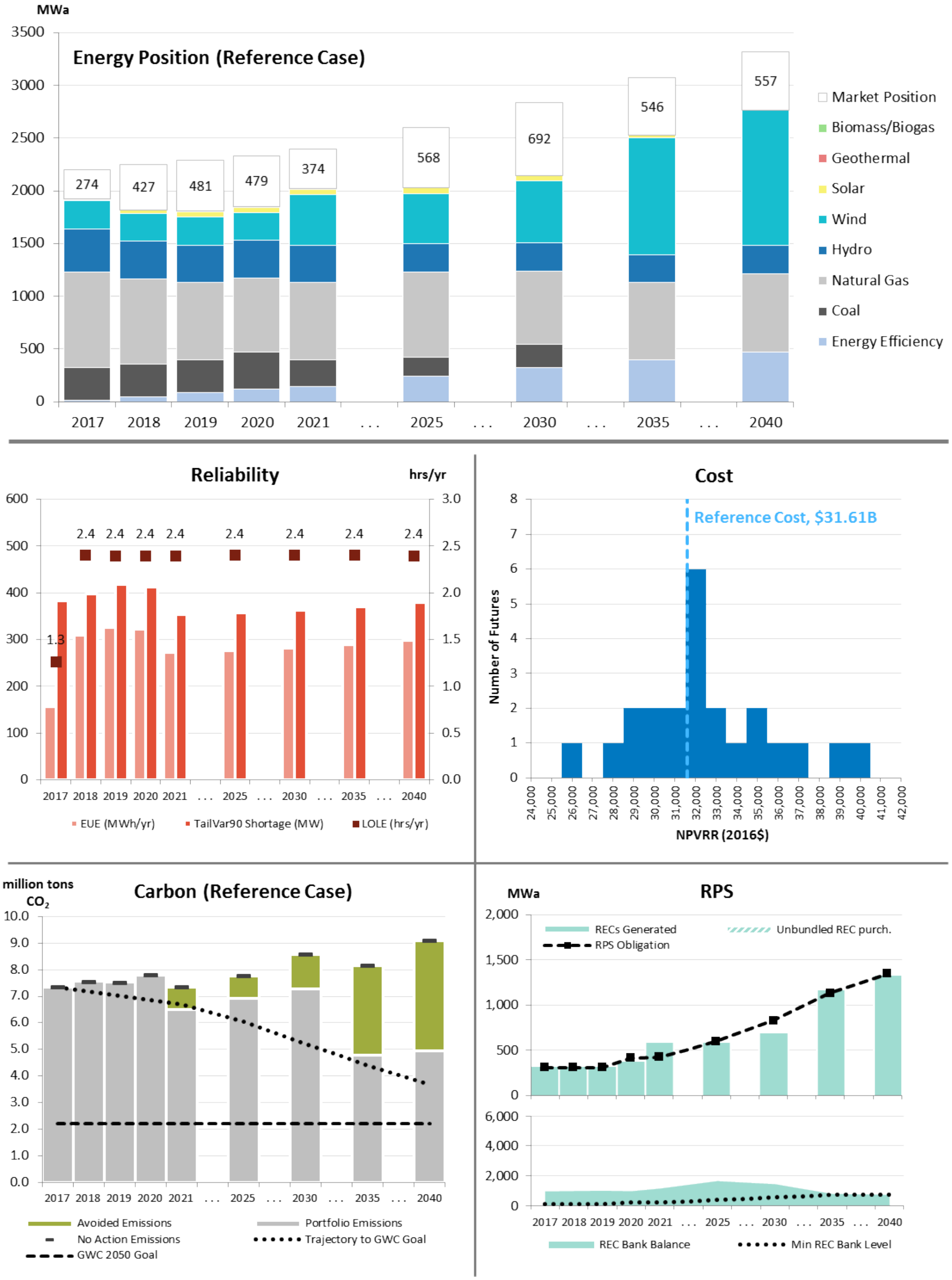


FIGURE O-38: Portfolio 19 output summary



Portfolio 20: Efficient Capacity 2021 Minimum REC Bank

This portfolio studies an alternative RPS compliance strategy making full and immediate use of PGE's existing banked RECs. When compared to *Portfolio 3 – Efficient Capacity 2021*, this portfolio does not achieve physical RPS compliance by 2025. Additionally, this portfolio foregoes the opportunity to capture the 100% PTC benefit with a qualifying RPS resource addition in 2018. This portfolio delays incremental RPS resource actions until 2025 in order to deplete the REC bank to its minimum recommended level. The first RPS resource addition is 181 MWa in 2025 sized to meet the minimum recommended REC bank by year end 2029. RPS resources providing 353 MWa and 320 MWa in 2030 and 2035, respectively, are then required. The delay in RPS additions also impacts the generic capacity additions needed to achieve resource adequacy. *Portfolio 20* can be compared with *Portfolio 3* to gain information regarding the potential costs/benefits of foregoing the 100% PTC resource in favor of deferring incremental RPS resource actions without relying on unbundled RECs.

TABLE O-21: Portfolio 20 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	-	-	-	-		532		1,569		2,511		3,073
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	389		389		389		389		389
Generic Capacity	-	352	379	379	445		704		851		1,310		1,562

FIGURE O-39: Portfolio 20 cumulative resource additions, capacity (MW)

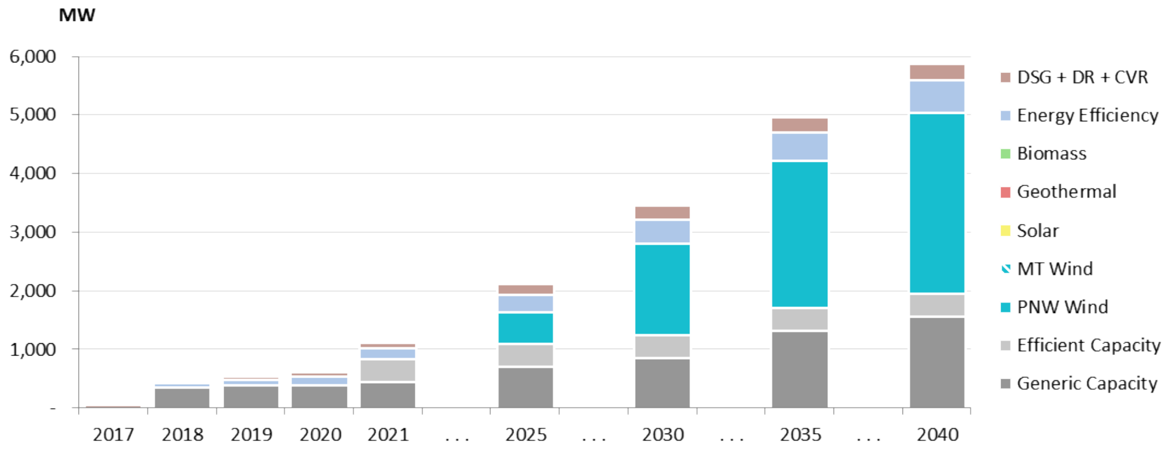
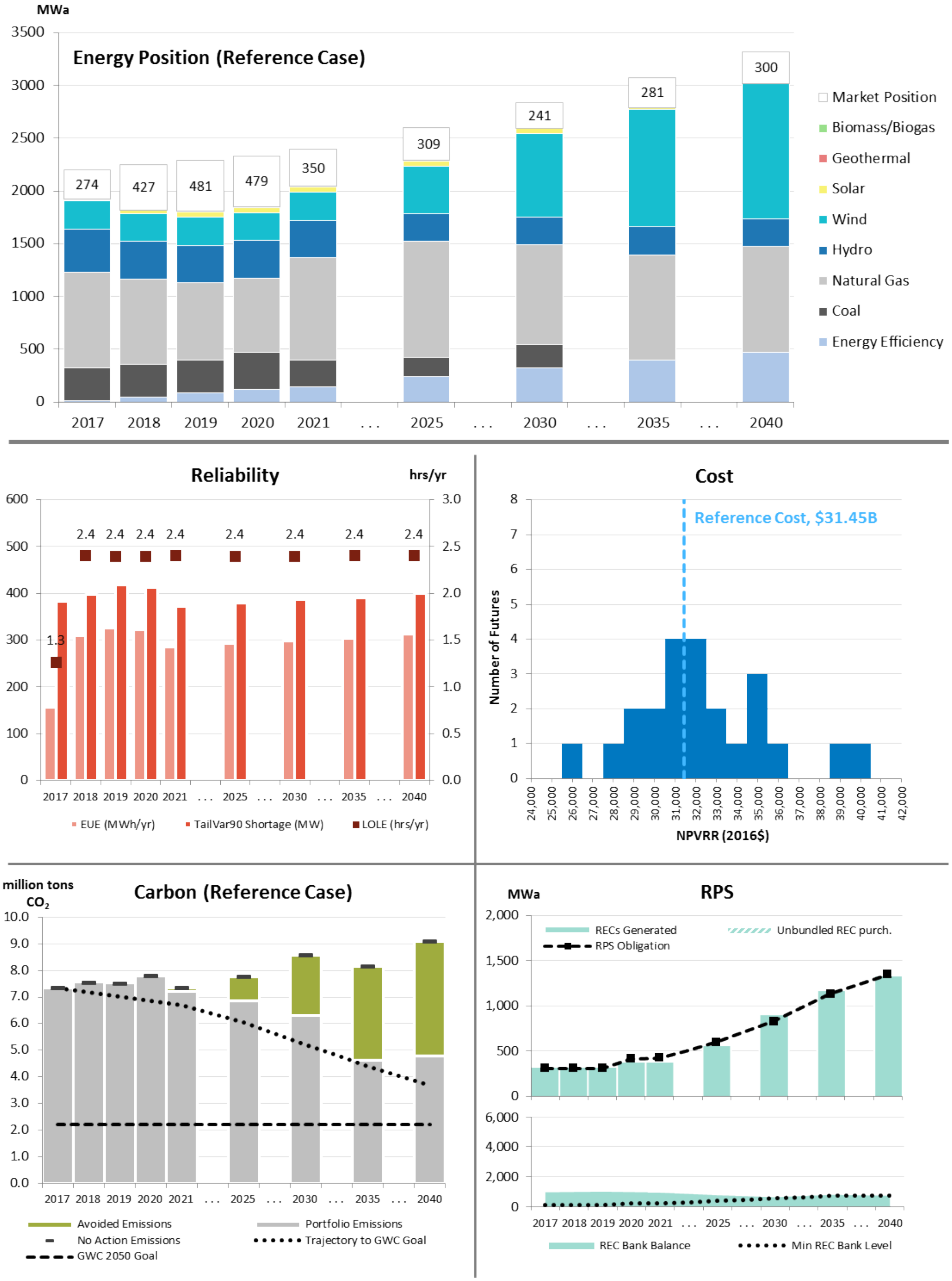


FIGURE O-40: Portfolio 20 output summary



Portfolio 21: Efficient Capacity 2021 20% Unbundled RECs

Similar to *Portfolio 20 – Efficient Capacity 2021 Minimum REC Bank*, this portfolio defers incremental RPS resource actions until 2025. However, this portfolio includes an assumption that sufficient unbundled RECs are available to fill 20% of PGE's annual RPS obligation during the period 2016–2021. PGE does not assign the unbundled RECs an explicit cost in the portfolio. The 2025 RPS resource addition represents 98 MWa to satisfy PGE's minimum REC bank requirement. This portfolio includes subsequent RPS resource additions of 436 MWa in 2030 and 320 MWa in 2035. The generic capacity additions are adjusted compared to Portfolio 20 due to the changes in RPS additions in 2025 and 2030. Comparing *Portfolio 3 – Efficient Capacity 2021* and *Portfolio 21* provides information regarding the potential costs/benefits of pursuing a strategy that both defers RPS resource actions and relies on unbundled RECs relative to a strategy that procures a 100% PTC qualifying resource. Furthermore, a comparison of *Portfolio 20* and *Portfolio 21* allows PGE to approximate a break-even price for unbundled RECs, given a strategy to draw the REC bank to its minimum recommended level.

TABLE O-22: Portfolio 21 cumulative resource additions, capacity (MW)

Resource	2017	2018	2019	2020	2021	...	2025	...	2030	...	2035	...	2040
Energy Efficiency	16	61	104	144	180		297		404		490		571
DSG	4	9	13	17	22		30		39		48		57
DR	26	29	31	69	77		162		187		198		198
CVR	-	0.4	0.9	1.3	1.8		3.7		6.3		9.3		12.5
PNW Wind	-	-	-	-	-		287		1,569		2,512		3,074
MT Wind	-	-	-	-	-		-		-		-		-
Solar	-	-	-	-	-		-		-		-		-
Geothermal	-	-	-	-	-		-		-		-		-
Biomass	-	-	-	-	-		-		-		-		-
Efficient Capacity	-	-	-	-	389		389		389		389		389
Generic Capacity	-	352	379	379	445		726		874		1,310		1,563

FIGURE O-41: Portfolio 21 cumulative resource additions, capacity (MW)

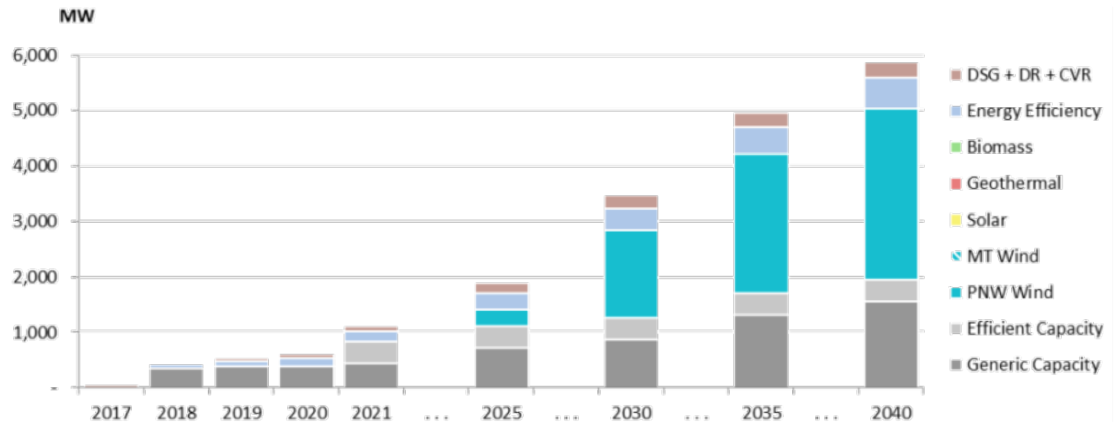
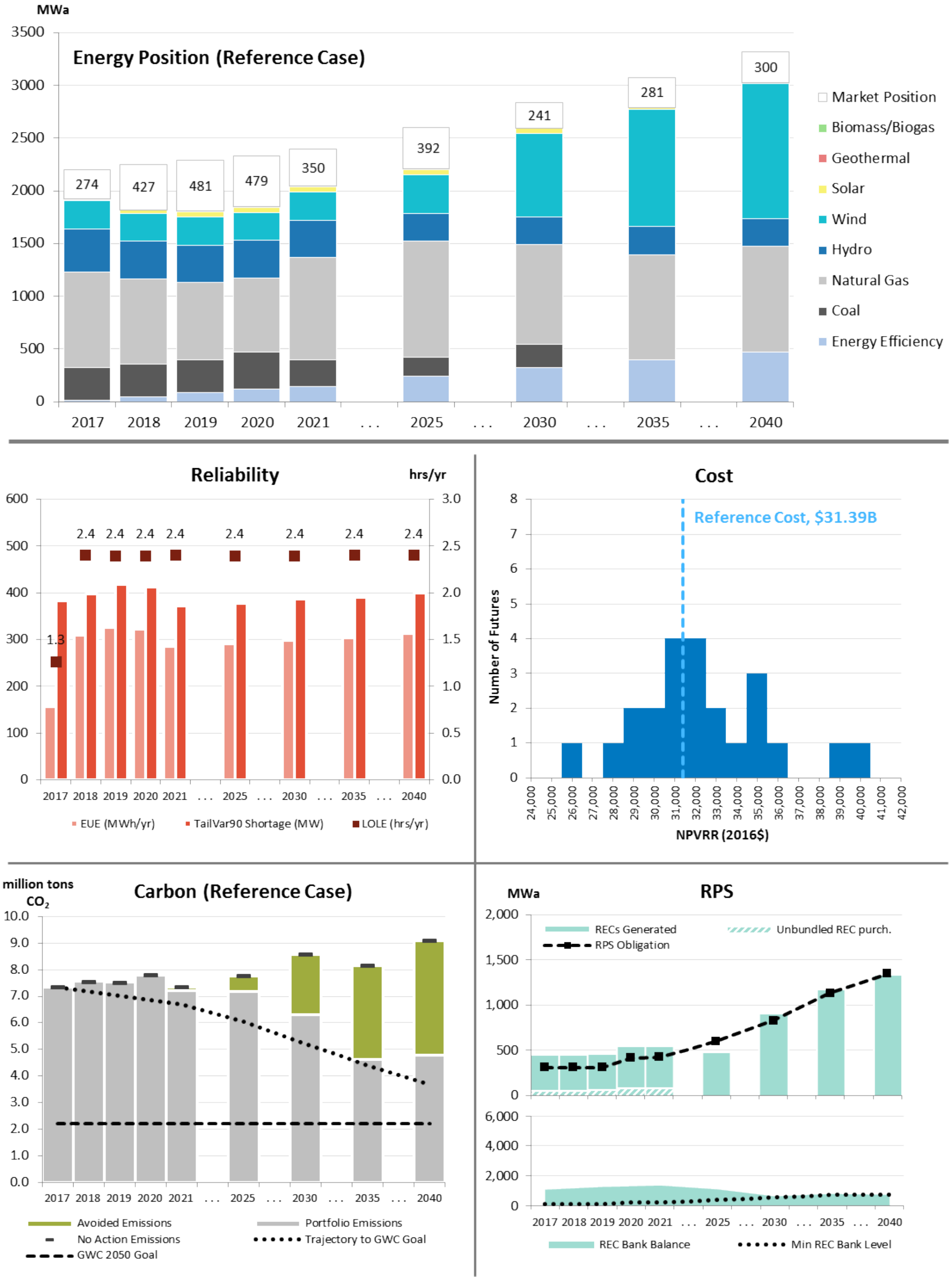


FIGURE O-42: Portfolio 21 output summary



APPENDIX P. Load Resource Balance Tables

This appendix provides the tables associated with the capacity and energy load-resource balance (LRB) figures in Chapter 5, Resource Adequacy. Additionally, it provides the table associated with the RPS REC obligation and production figure in Section 5.4, Renewable Portfolio Standard – REC Obligation and Production.

P.1 Estimated Annual Capacity Need, MW

Table P-1, which is the tabular format of Figure 5-1 for 2017–2040, describes PGE's resources from a capacity perspective and identifies the remaining capacity need given no incremental resource additions (with the exception of EE, DR, and DSG actions).

Notes for Table P-1:

- The values in Table P-1 are for summary purposes and do not reflect the complexity of the load or resource modeling in RECAP (as discussed in Chapter 5, Resource Adequacy).
- **Resources** are summarized based on average annual capacities or ELCC values. Hydro and Wind+Solar include leased and contracted resources. DSG and DR targeted acquisitions are included.
- **Load** is the 1-in-2 peak load adjusted for EE actions, excluding long-term opt-outs.
- **Capacity Shortage** is the need for additional capacity calculated by RECAP in order to achieve the adequacy target. It is expressed in terms of MW of conventional units (100 MW, 5 percent FOR). Positive values indicate need.
- **Total Reserve Margin** (TRM) is calculated as Total Resources plus Capacity Shortage minus Load.
- **TRM%** is the ratio of TRM to Load.

TABLE P-1: PGE's estimated annual capacity need, MW

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040
Gas	1810	1810	1810	1810	1810	1810	1810	1810	1810	1810	1810	1810
Hydro	831	796	700	700	700	700	700	700	464	464	464	464
Wind+Solar	146	153	183	182	176	176	176	177	177	170	138	106
Coal	752	752	809	809	296	296	296	296	296	296	0	0
Contracts	390	84	30	11	11	11	11	11	11	4	2	2
Spot Market	119	106	97	107	98	101	103	104	107	114	108	101
DSG	118	123	127	131	135	138	140	142	144	153	162	171
DSM	30	33	35	73	81	108	131	150	166	191	202	202
Total Resources	**4195**	**3856**	**3791**	**3822**	**3307**	**3339**	**3367**	**3390**	**3175**	**3202**	**2887**	**2857**
Load	**3446**	**3453**	**3468**	**3472**	**3525**	**3558**	**3591**	**3625**	**3660**	**3843**	**4041**	**4258**
Total Reserve Margin	616	755	701	707	602	612	622	633	658	694	710	742
TRM%	18%	22%	20%	20%	17%	17%	17%	17%	18%	18%	18%	17%
Load + TRM	4062	4209	4170	4178	4126	4169	4213	4258	4317	4537	4751	4999
Capacity Shortage	**-133**	**352**	**379**	**356**	**819**	**831**	**846**	**868**	**1143**	**1335**	**1864**	**2143**

P.2 Projected Annual Average Energy Load-Resource Balance, MWa

Table P-2, which is the tabular format of Figure 5-23 for 2017–2040, describes PGE's energy load-resource balance (LRB) given no incremental resource additions (with the exception of EE actions).

Notes for Table P-2:

- Additional discussion is provided in Section 5.5, Energy Load-Resource Balance.
- The energy LRB is based on **annual average available energy**, not economic dispatch.
- **Thermal resources** are adjusted for maintenance and forced outage rates. Duct firing and peaking units are excluded.
- **EE actions** are included as a resource.
- **Load** is the 1-in-2 annual average load excluding opt-outs and before incremental EE actions.

TABLE P-2: PGE's projected annual average energy load-resource balance, MWa

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040
Gas	920	920	920	920	920	920	920	920	920	920	920	920
Hydro	456	422	350	350	350	350	350	350	257	257	257	257
Wind+Solar	282	299	320	320	320	320	320	320	320	312	280	237
Coal	656	656	705	705	262	262	262	262	262	262	0	0
Contracts	16	10	11	11	11	11	11	11	11	4	1	1
Energy Efficiency	13	49	84	116	145	171	195	218	239	328	399	467
Total Resources	**2343**	**2355**	**2389**	**2421**	**2007**	**2033**	**2057**	**2080**	**2008**	**2082**	**1856**	**1882**
Load	**2200**	**2247**	**2290**	**2331**	**2395**	**2449**	**2501**	**2553**	**2602**	**2844**	**3082**	**3332**
Energy Deficit	**(143)**	**(107)**	**(100)**	**(90)**	**388**	**416**	**444**	**473**	**594**	**762**	**1225**	**1451**

P.3 PGE's Projected RPS REC Obligation and Production

Table P-3, which is the tabular format of Figure 5-22 for 2017–2040, lists PGE's projected REC obligations for compilance with Oregon's RPS and PGE's projected REC production given no incremental resource additions. Additional information is provided in Section 5.4, *Renewable Portfolio Standard – REC Obligation and Production*.

TABLE P-3: PGE's projected RPS REC obligation and production, MWa

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040
REC Obligation	309	310	312	417	424	429	434	439	600	828	1135	1347
REC Production	338	338	338	386	387	387	387	387	387	378	330	302

APPENDIX Q. Regulated Utilities Investing in Natural Gas Reserves and Production: Recommendations on How to Avoid the Risks and Capture the Prize (BRG Energy)

REGULATED UTILITIES INVESTING IN NATURAL GAS RESERVES AND PRODUCTION: RECOMMENDATIONS ON HOW TO AVOID THE RISKS AND CAPTURE THE PRIZE

BRG
Energy

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Abstract

Regulated utilities' growing need to secure long-term natural gas at low prices and with low volatility has many executives investigating whether owning reserves and production is the means to achieve these goals. Some regulators are supportive—for now. Shale gas has changed the upstream game, and these executives would do well to understand how before committing to these long-term deals.

The Prize

Regulatory forces operating against coal, coupled with the market forces unleashed by the unconventional resource (e.g., shale gas) revolution, have resulted in dramatic growth of natural gas–fired generation. Future additions to generation capacity will include renewable sources but will be increasingly dominated by natural gas. Many executives of regulated utilities, both electricity and gas, face a growing challenge of supplying this natural gas–fired generation and other natural gas demands.

Commodity market solutions are subject to significant price volatility and potentially unfavorable prices. Financial instruments to reduce volatility consume significant credit capacity and may present significant accounting issues, and long-term solutions can be expensive. Consequently, a number of investor- and municipally owned regulated utilities have already launched, or are actively considering launching, ventures to acquire natural gas reserves and production.

Public utility commissions (PUCs) have approved those endeavors already underway, and some PUCs are actively supporting those being considered. Four factors have been identified by the PUCs in justifying these programs that we collectively refer to as "the prize."

The prize is attainable but unlikely to be captured unless leaders of regulated utilities deeply understand the idiosyncratic risks and rewards of unconventional resources.

First, the opportunity to achieve low-cost supply is generally assumed. This assumption is based on the belief that public utilities can reduce the cost to their customers by reducing the profit margin of displaced intermediary agents, particularly given regulated utilities' lower cost of capital. Second, it is believed that direct ownership of production will reduce the exposure to large price swings. Third, the risk is low, because of both the abundance of natural gas given the unconventional resource revolution and the nature of the commercial terms. Fourth, PUCs (so far) claim that the tradeoff of risk and reward among the different parties is "fair."

For investor-owned regulated utilities, substantial additional reward is available that successfully captures the prize for their customers, and the investments in reserves and production represent a significant growth opportunity. A mid-sized regulated utility could add $200 million a year to its capital base, which in many cases could translate into an annual dividend growth of about 3 percent from just the investments associated with long-term natural gas supply.

The prize is attainable but unlikely to be captured unless leaders of regulated utilities deeply understand the idiosyncratic risks and rewards of unconventional resources.

Deals Are Getting Done

Some municipal utilities, faced with the prospects of $10/mmbtu gas in the early 2000s, decided to forge an innovative supply solution. This included the Los Angeles Department of Water and Power reserves deal to support over 1.4 million customers in Los Angeles County and Public Gas Partners' deals to support municipal utility customers in Florida, South Carolina, Georgia, Alabama, and Tennessee.

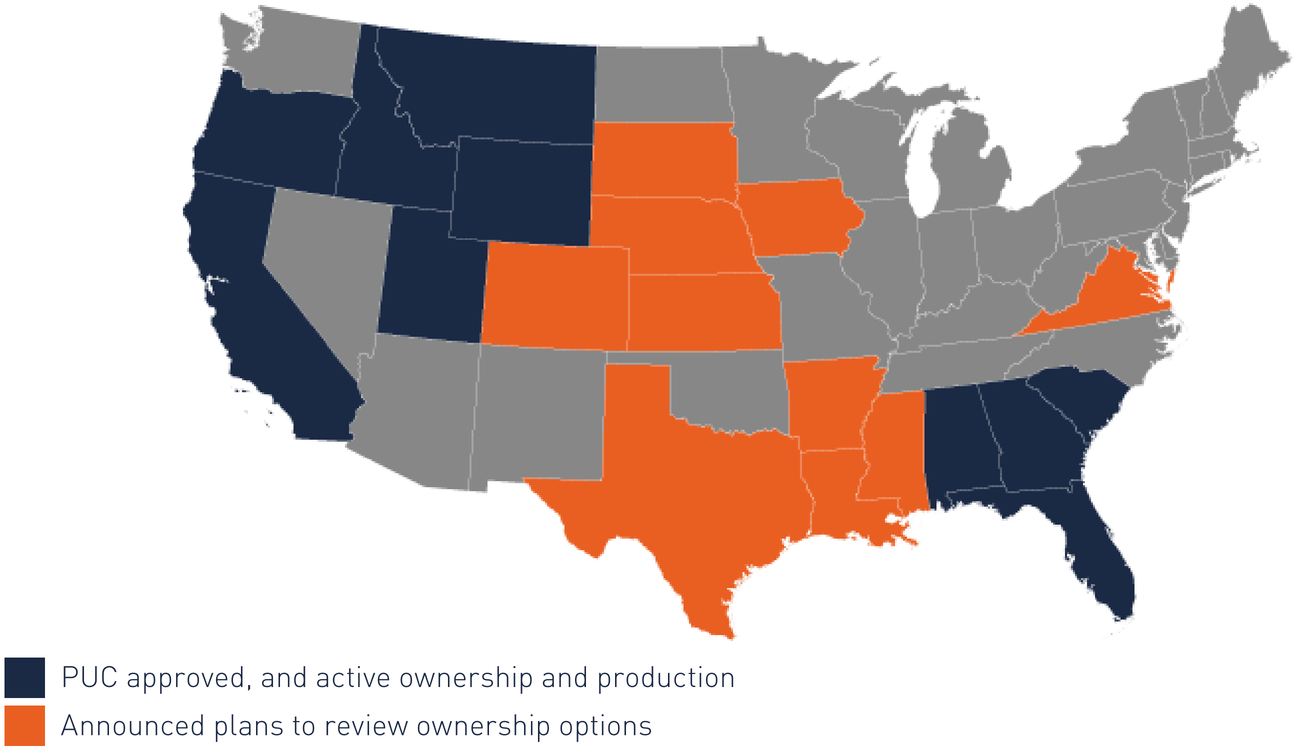
NW Natural's deal with Encana in the Jonah field to provide long-term gas supply to about 600,000 customers in Oregon is an example of an investor-owned utility deal. The initial supply agreement provided only 10 percent of NW Natural's natural gas, but the program was targeted to provide up to 25 percent of gas needs. The commercial relationship between NW Natural and Encana followed the operator/non-operating working-interest owner model common in the oil and gas sector. The particular land deal was fairly sophisticated and allowed NW Natural to participate in a number of wells, not only newly drilled wells.

Questar Gas, a regulated utility, has implemented a different commercial solution to provide over 60 percent of the gas needs of its over 1 million customers in Utah and Wyoming. Wexpro, an unregulated oil and gas company wholly owned by the Questar Corporation, provides "cost-of-service" gas to Questar Gas. Questar emphasizes the capture of lower-cost gas and lower volatility for its customers and captures much of the economic benefit for its shareholders within Wexpro. Questar Gas recently went public about expanding Wexpro's "cost-of-service" supply to other utilities.

Northwestern Energy, a diversified regulated electricity and gas utility with over 600,000 customers in Montana, South Dakota, and Nebraska, owns and operates natural gas production directly. It has targeted producing 50 percent of its core gas needs, or currently about 12 BCF per year. This allows it to earn a return of and on costs associated with this production, as opposed to a cost "pass-through" on an equivalent purchase of gas.

FIGURE 1: CURRENT STATUS OF REGULATED UTILITIES OWNING NATURAL GAS RESERVES AND PRODUCTION

Current Status of Regulated Utilities' Ownership of Natural Gas Reserves



Florida Power and Light (FP&L) has received PUC approval to recover costs, and returns on those costs, for its share of development costs in the Woodford Shale in Oklahoma that it received in a deal with Petroquest. FP&L has made clear that this is just the first of many deals.

Other regulated utilities have likewise signaled their intentions to acquire natural gas reserves and production, including Black Hills' plans for regulated utilities in South Dakota, Nebraska, Colorado, Kansas, and Iowa. Other companies, including Southern Company, Duke Energy, and Xcel Energy, have made public statements that they are actively investigating the opportunities, but have not provided specifics.

> *"We will begin working with our commission and major stakeholders to explore rate basing natural gas reserves as a way to take advantage of the current low natural gas price and to provide a longer-term hedge for our customers."* —***Ben Fawke, chairman/CEO, Xcel Energy***

Why Now?

Long-term gas supply has been an issue for a while, so the recent intensity in regulated utilities' interest in owning natural gas reserves and production raises the timing question. Several factors make this a pressing issue and suggest the window of opportunity may be limited. Regulatory pressures by the Environmental Protection Agency and others to limit coal were clearly a catalyst, but most do not consider that these pressures will reverse. A belief that creates more urgency and may argue for a limited window is that natural gas prices are currently low compared to future prices, and thus locking in deals now will benefit regulated utility customers. Low oil prices are causing many oil and gas companies to become distressed and potentially more open to deals beneficial to regulated utilities. Part of the urgency is the large uncertainty on how long oil prices will remain low.

These trends spurring interest are exogenous to the regulated utility industry, but two factors within the industry make the timing right. First, existing opportunities to invest and grow the capital base are limited in both electric and gas utilities. Sluggish GDP growth, demand destruction, and other drivers do not leave the industry many capital opportunities. Second, the regulatory construct is evolving in ways that have PUCs moving beyond meeting fixed goals (e.g., RPS) and demanding that utilities provide "optimal resource plans" that must balance more choices (e.g., distributed energy) over longer periods of time. Supply of natural gas becomes more critical under this scrutiny. Finally, many PUCs have recently expressed considerable interest in a business model of utilities owning reserves and production.

These exogenous and regulated utility industry factors are pushing executives to investigate now, and quickly, whether they should own natural gas reserves and production.

Unconventional Gas Is Different

Natural gas supply in North America has been transformed because of the unconventional resource revolution, and the technological genie will not be put back in the bottle. Future gas supply will be dominated by unconventional gas, predominately shale gas. This supply revolution, like most "overnight" successes, was decades in the making. Regulated utility leaders must realize that unconventional gas is different from conventional gas to successfully determine if natural gas reserves and production ownership are the right strategy for their companies. The differences are geological, operational, technological, and managerial. The true risk and reward relationship cannot be captured without an understanding of these differences.

The discussion below is based on our unconventional resource practice experience, which began in 1996 with an early evaluation strategy in the Barnett Shale and has included buy-side transaction and field development support in over 30 plays in North America and about 10 outside of North America.

Unconventional Gas Is Abundant

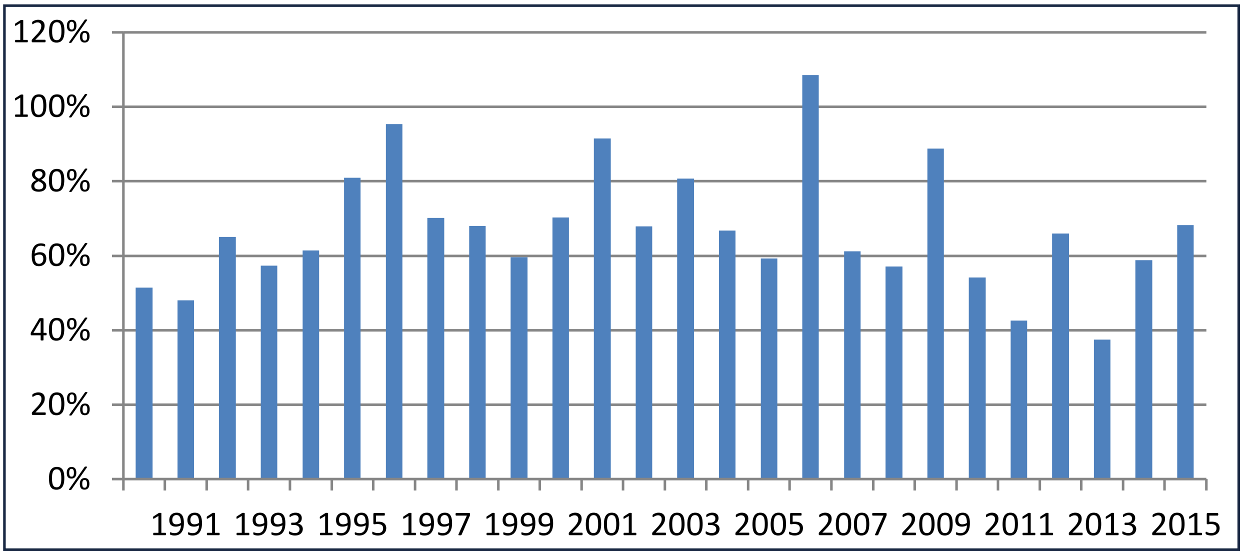
The first difference that unconventional gas has wrought on North American supply is the simple reality that natural gas is abundant, which has yet to fully change strategy and planning at regulated utilities, PUCs, and federal agencies. In our practice, we frequently see long-term strategies and planning processes dominated by ideas about a scarce and dwindling resource base. This out-of-date view may lead to bad strategies.

Abundance implies an increase in security of supply, but that does not mean that no risk to supply exists, as will be discussed below. Additionally, abundance is taken by some as assurance that price volatility should significantly decrease; however, as shown in Figure 2, the general trend towards lower volatility seen in natural gas markets since the emergence of unconventional gas has been reversed in the past 24 months. Projections of permanently reduced volatility should be considered highly uncertain.

Unconventional Plays Are Concentrated

FIGURE 2: ABUNDANCE DOES NOT MEAN VOLATILITY IS PERMANENTLY REDUCED

NYMEX Natural Gas Front Month: Interday Volatility on Annual Basis

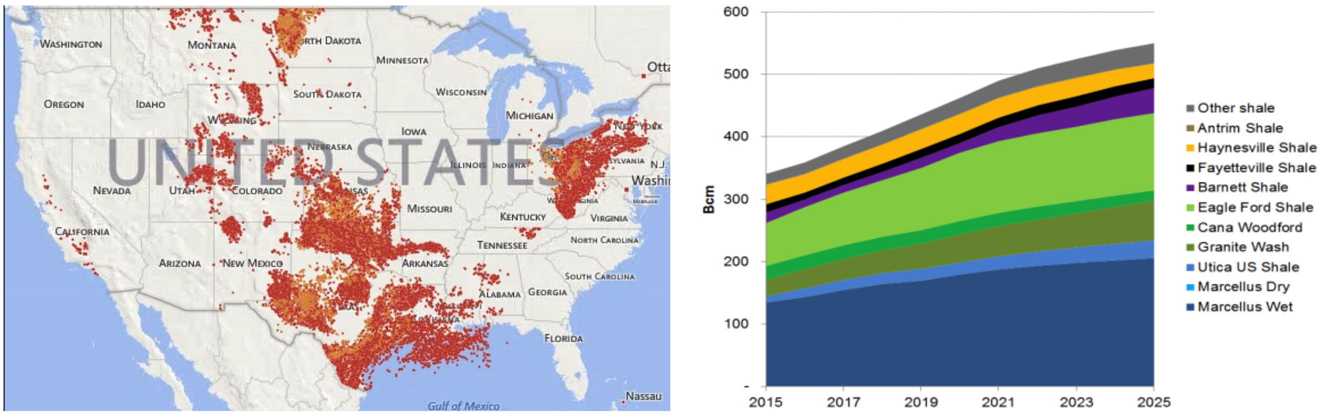


The unconventional revolution is dominated by relatively few extremely large plays. Figure 3 shows that the more than 200,000 natural gas–directed wells drilled since 2003 are highly concentrated. The future production of unconventional gas (two-thirds of national supply) is expected to likewise be dominated by several plays. As explained below, there are technical reasons why there will never be a small unconventional play.

Executives of regulated utilities considering a role in gas production need to understand the implications of this concentration to their business. First, the physical location of available gas (dominated by the shale plays) supply and utility demand is a key consideration when crafting commercial terms. In many cases, direct supply will not be practical, and other transfer elements of the deal will be needed. Another consideration is the infrastructure challenge of this concentration. Bottlenecks have been a stumbling block, and there is no reason to expect these will not occur in the future. Control over bottlenecks might convey significant value, but it also argues for the importance of a "first-to-market" strategy for utilities. Finally, while the resource is highly geographically concentrated, ownership of these resources is not. There are currently over 200 operators or active participants in the Eagle Ford. Consolidation of this diversity in ownership is likely, and current industry distress may accelerate this consolidation. This should motivate regulated utility leaders towards making reserves decisions quickly.

FIGURE 3: UNCONVENTIONAL RESOURCES ARE GEOGRAPHICALLY CONCENTRATED

The majority of the ~200,000 gas directed wells drilled since 2003 are highly concentrated, as is the expectation for future gas production



Source: Drilling Info, BRG Analysis

Unconventional Plays Are Statistical

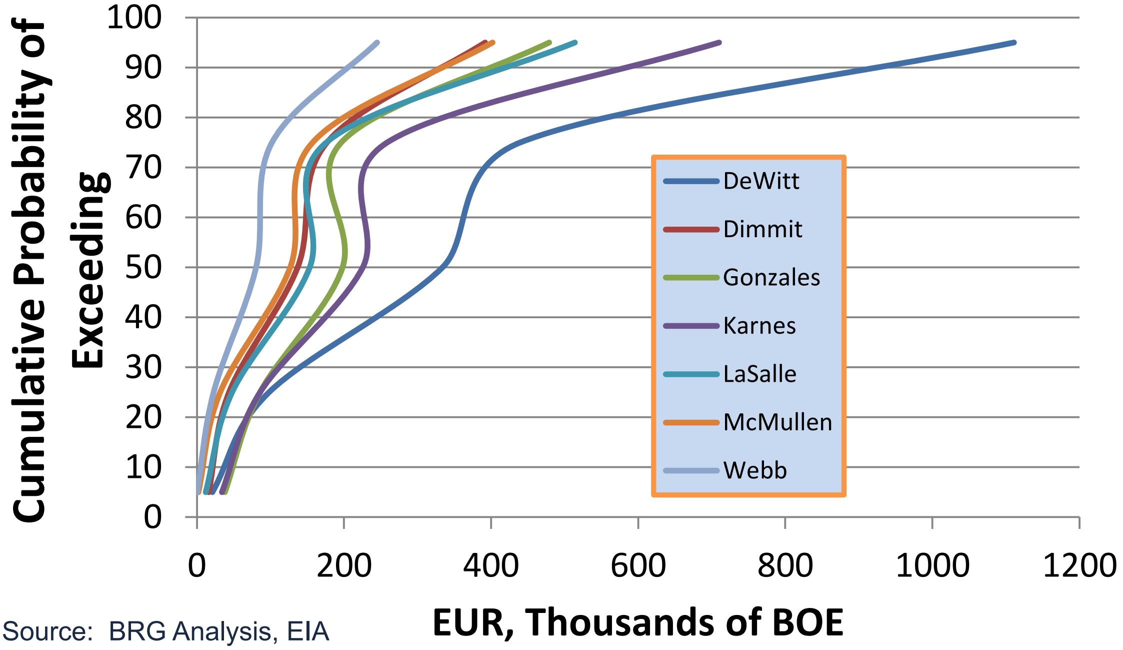
Unconventional plays are big, and North America has an abundance of natural gas as a result. This does not mean that significant uncertainty does not exist at the level of individual wells. The performance from well to well, and sometimes adjacent wells, is highly variable. It is not uncommon in some plays for 25 percent of wells to never produce. For those wells that do produce, easily 50 percent may never be profitable.

This statistical performance may improve with time, but very slowly. This phenomenon is not well understood outside of those intimately involved in unconventional resource development, and this includes, in our experience, many financial investors. This critically important characteristic is missed in part because non-industry participants continue to use the "exploration and production" (E&P) paradigm of conventional resources. Exploration doesn't really apply to unconventional reservoirs, since we've known the location of these resources for decades. Likewise, "sweet spots" are, for the most part, not found through exploration or remote sensing like seismic, but are uncovered as a result of adaptive learning applied to many wells.

The correct paradigm is one of "design and manufacture," and the inherent uncertainty in individual well performance must be correctly understood. Figure 4 is an example of this well uncertainty in mature sections of the Eagle Ford play drilled in 2013. Even here, at this stage of development, potentially 50 percent of wells will not be economic. However, at the portfolio level (hundreds or thousands of wells), the odds become high that the performance of this portfolio of wells will create value.

The fact that unconventional plays are "statistical" should inform regulated utility leaders about what types of deals to consider. Clearly, any deal should provide a critical mass of wells to provide a reasonable level of certainty that performance targets will be met. This, in turn, may influence decisions as to whether to "go alone" or combine with others to achieve critical mass. Choices with regard to participation in new wells or a mix of new and existing wells should be informed by the statistical nature of unconventional resources as well.

FIGURE 4: SIGNIFICANT VARIATION IN WELL PERFORMANCE IS CHARACTERISTIC OF UNCONVENTIONAL RESOURCES



Estimated Ultimate Recovery by Well: Eagle Ford Play (by County)

Source: BRG Analysis, EIA

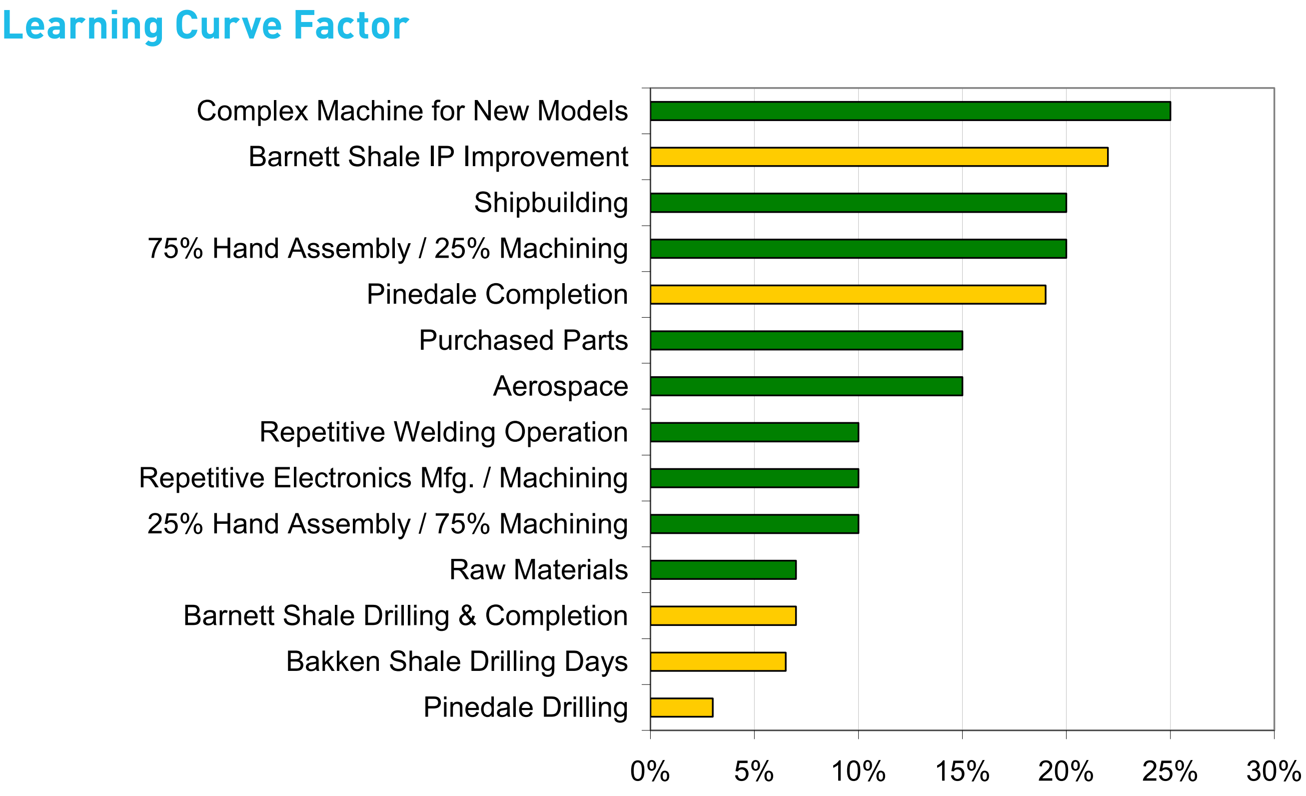
"Manufacturing Learning" Drives Unconventional Gas Success

Unconventional plays follow a design and manufacturing (D&M) business model, not the E&P business model common in conventional oil and gas. The opportunity to continuously improve the performance by improved designs (drilling, completions, logistics, etc.) is available to unconventional resources because development never stops, with tens of thousands of wells drilled over decades in a single play. This is in sharp contrast to a deepwater conventional play that may only have dozens of wells drilled in the first few years of a 20-year lifetime, and where management has limited opportunities to change the design.

Success in unconventional plays requires a type of "evolutionary fitness" that allows management the ability to change not only the technical specifications of well delivery but also the business-model choices of the enterprise. The impact of this evolutionary fitness is ever-improving performance along many key parameters, such as the number of days to drill a well, the initial production rate, the length of stimulated lateral, the number of fracs per lateral, and proppant amount and type. These improvements, or what we call "manufacturing learning," are the result of both step-changes (moving to pad drilling) and gradual changes (drilling non-productive time). Manufacturing learning is common to all manufacturing processes, and there are common methods to measure this dynamic. For example, figure 5 shows the Wright Learning Curve Factor (percentage increase/decrease in cumulative performance/cost every time the number of units doubles) for unconventional resource development compared to other manufacturing industries.

Manufacturing learning is the single biggest driver of the uncertain value of unconventional plays. For regulated utility executives, understanding manufacturing learning is central to making good decisions about owning natural gas reserves and production. First, the value of unconventional plays is driven greatly by manufacturing learning. Second, and something that many oil and gas participants and most financial analysts do not capture correctly, manufacturing learning will drastically impact future production estimates. Manufacturing does not happen by accident. "Managing to the learning curve" is a key to success in unconventional resources, and not all management teams are successful at this. Regulated utility experts must understand this during the selection of partners and must monitor and engage these partners throughout the lifecycle of the unconventional resources. Passive investing in unconventional plays is not a route to success; rather, utilities that choose to have others operate must at a minimum ensure that operators are meeting manufacturing learning targets. Otherwise, costs and production will not be competitive, and "the prize" of reserves ownership will not be captured.

FIGURE 5: LEARNING FACTORS OF UNCONVENTIONAL RESOURCES


Learning Curve Factor

Source: BRG analysis, NASA

Unconventional Plays Are Infrastructure Plays

The final characteristic of unconventional resources that regulated utilities leads must capture in their decisions regarding natural gas reserves ownership is that unconventional plays are "infrastructure plays." Development never stops in unconventional plays because of the high decline rates of wells and the low recovery efficiencies. This means that many more stakeholders (landowners, communities, municipalities, NGOs, etc.) will be directly impacted and thus involved over a much longer period. The preferences of this stakeholder group are critical to the ability of unconventional resources to be developed. These preferences can, and most likely will, change over time and as a result create risks and opportunities for future developments.

Regulated utility participation is based inherently on long-term needs. Regulated utilities that are investigating reserves ownership need to consider risks to long-term development created by the infrastructure intensity of unconventional resources.

Charting a Path Forward

The prize of lower natural gas prices, lower price volatility, lower risk supply, equitable allocation of risks and rewards, combined with significant opportunities to grow the capital base of investor-owned regulated utilities, is real but not given. It is critical that regulated utility executives simultaneously solve both the "strategy" and "organizational" challenges that owning natural gas reserves and production present, particularly given the unique attributes of unconventional gas discussed above.

The go versus no-go strategic decision cannot be made in isolation from decisions including which play or plays to participate in, which operators or partners to participate with, how to structure the commercial terms, whether to participate in newly drilled wells or existing wells or a mix of both, and how many wells to participate in and over what time frame. The unique attributes of unconventional gas discussed above will influence all of these decisions. As a result, regulated utility executives need to incorporate these factors into their strategic decisions.

Table 1 summarizes where the unique attributes of unconventional gas most impact the capture of the prize and, as a result, where regulated utility leaders should focus their attention. Those attributes that either unambiguously support (shown as checks) or hinder (shown as minus signs) should not be the strategic focus of regulated executives, because while these are value relevant, management's strategic decisions will have limited impact. Executives should focus on where their specific decisions can create opportunities or reduce risk (shown in Table 1 as "+/-" sign).

The fact that unconventional resources are "statistical" plays is a good example of where strategic focus should be placed. This can be demonstrated by considering a mid-sized utility targeting half of its gas needs to be met by a natural gas reserves/production acquisition and using the Fayetteville shale as a target resource. The Fayetteville shale has been able to stabilize production at about 3 BCF per day by drilling about 700 wells per year (~5,000 wells drilled to date). A mid-sized utility may have total gas needs of about 30 BCF per year (half of 60 BCF per year) which translates into participating in only 3 percent of the total wells drilled within the Fayetteville each year. This small of a percentage—given that 30 percent of wells drilled may not be economic in any given year—puts regulated utilities' position at significant risk. Thus, regulated utility leadership needs to develop strategies to create a critical mass position to reduce exposure to the statistical risks of unconventional gas. This can be done via a combination of play selection, operator selection, commercial terms, pooling with other regulated utilities, and other means.

TABLE 1: UNIQUE ATTRIBUTES OF UNCONVENTIONAL PLAYS IMPACT CAPTURING THE PRIZE

Unconventional Resource Attributes

Elements of the "Prize"	*Abundance*	*Concentrated*	*Statistical*	*Manufacturing Learning*	*Infrastructure*
Low Cost	✓	-	+/-	+/-	+/-
Low Volatility	+/-				-
Low Risk	✓				
Fair		+/-			?
Capital Growth					✓

Manufacturing learning is another example where the unique attribute of unconventional gas plays requires regulated utility management's strategic focus when deciding upon a natural gas reserves and production investment. Utilities leaders need to consider not only how manufacturing impacts the value of a transaction but also how this learning should be a key input into which partners to select, which plays to participate in, and how to structure the commercial terms of a deal.

The right investment strategy is not enough; leaders of regulated utilities must also choose an organizational model congruent with the investment strategy—and they must do this before investing. A partial range of organizational models is revealed by those regulated utilities that currently own natural gas reserves and production.

Some companies have oil and gas operations within the company. Clearly, this requires either substantial current capabilities (e.g., long history of gas operations in storage) or plans to acquire these capabilities (e.g., acquire assets and talent of small oil and gas company).

On the other end of the spectrum, some companies have chosen the common non-operating working-interest owner role. However, this is not a "passive investor" role. As per industry best practice, a non-operating party is provided not only the opportunity but also the expectation to be an active participant in many oil and gas activities within industry-standard joint operating agreements (JOAs). While common industry practice is to refer to parties in JOAs as "partners," it is also industry practice that each party has the responsibility to ensure its own interests are protected. Passive investing, especially in unconventional resources where development never stops, is understood within the industry to not be a best practice and will almost certainly not lead to success.

Regulated utility leaders that choose to be non-operating partners still need to decide, before investing, how to build the organizational capabilities to be a non-operating party that adds value through active participation, as well as how to build the capabilities to ensure operators achieve high performance (e.g., achieve industry learning curves).

Conclusion

Regulated utility ownership of natural gas reserves and production can provide significant benefits to customers and shareholders. However, leaders will need to focus on both the strategic drivers of unconventional resources and building the organizational capabilities congruent with their chosen natural gas investments.

About the Authors

Gardner W. Walkup, Jr.

Gardner W. Walkup, Jr. is a global energy executive, innovative strategist, trusted advisor to corporate management and boards, and energy expert for law firms, industry clients, and regulatory agencies. He has developed and implemented strategic transformations and led the alignment of corporate culture and competencies necessary to implement these strategies. He has a deep understanding of the energy value-chain, from land acquisition and exploration through power distribution and energy marketing. He brings a keen understanding of geopolitical, economic, commercial, operational, and technical risks, as well as experience in over 30 countries representing capital investments of more than $300 billion.

As a corporate executive, Mr. Walkup has chaired an Investment Committee directing overall corporate capital allocation, led the development of a new corporate strategy that drastically narrowed investment focus and reduced costs, and led the design and implementation of culture change and capability building efforts in response to new strategies and major acquisitions.

Mr. Walkup is a recognized expert in energy asset valuation and mega-project management. He has advised corporate boards and executives investing globally in unconventional resource plays, including shale gas, tight oil, and coal-bed methane, and investments in global mega-projects with capital requirements of more than $5 billion. He has significant experience in LNG and deepwater development. In addition, Mr. Walkup has advised corporate leadership on portfolio management, transaction support, business-unit growth strategies, and project management leadership capability building.

Mr. Walkup's expert advisory experience includes significant international litigation and arbitration matters concerning industry practices in mega-project development, offshore operations, and operating/non-operating party industry best practices.

Mr. Walkup started his career at Chevron, where he served as senior reservoir engineer for a 250,000-barrel-a-day oil field in Indonesia, led strategic planning and petroleum engineering for a major offshore Gulf of Mexico development, managed a corporate project to improve economic valuation methodologies of large capital projects, and developed novel reservoir-characterization approaches.

Adam Borison

Dr. Adam Borison is an internationally recognized consultant, academic, and entrepreneur. He specializes in the application of advanced analytic methods to strategy, valuation, and risk assessment in power and fuels. Dr. Borison has led numerous engagements in investment strategy, corporate mergers and acquisitions, environmental resources management (ERM), project planning and evaluation, product design and research and development, capital allocation, government policy and regulation, and litigation/arbitration. He has broad experience across a range of geographies, technologies, and applications.

Most recently, Dr. Borison advised on pipeline gas/power business strategy in the Midwest United States, supported utility resource planning efforts involving tens of billions in dollars of generation and transmission facilities in Canada, and helped develop renewable energy policy and regulation in the Caribbean. He has also worked on dozens of capability-building engagements for clients involving data development, model transfer, results review, training and coaching. Dr. Borison has submitted expert testimony in arbitration, litigation, and regulation settings extending from the Gulf of Mexico to Kurdistan.

Dr. Borison has served on the visiting faculty at Stanford University, U.C. Berkeley, and the University of Cambridge, teaching courses both specifically in the energy business and generally in management methods. Most recently, he co-taught a renewable energy project development course at Stanford. Dr. Borison is widely known as an expert in management science and operations research, especially decision/risk analysis, real options, and other forms of uncertainty analysis. He has authored several articles on the application of analytic methods in leading publications such as The Electricity Journal, Public Utilities Fortnightly, Sloan

Management Review, California Management Review, and the Journal of Applied Corporate Finance. Dr. Borison led the original development team for DPL, a leading decision and risk analysis software package now in its eighth release. He also co-founded Agni Energy, an India-focused bioenergy company.

Rick Chamberlain

Rick Chamberlain is an oil and gas professional with deep experience in unconventional resource valuation, unconventional and conventional resource assessment, monetization strategy development, field development planning, and mega-project management. Mr. Chamberlain has experience in more than 25 countries representing capital investments of more than $200 billion.

Mr. Chamberlain has advised corporate leadership and financial teams on unconventional oil and gas asset valuation (buy-side), resource assessment, production evaluation, and field development planning. Examples include properties in the Marcellus, Upper Devonian, and Utica fields in Pennsylvania; the Eagle Ford, Sprayberry, and Wolfcamp fields in Texas; the Bakken play in North Dakota; the Niobrara field in Colorado and Texas; the Horn River field in British Columbia; the Montney field in British Columbia and Alberta; coal-bed methane in Queensland, Australia; and the Vaca Muerta in Argentina.

Mr. Chamberlain also has direct industry exploration experience, including developing and implementing Chevron's Alaska Exploration strategy. This included negotiating farmouts, acquisitions and divestitures, and overall budget control. He and his team mapped the Chukchi Sea for the first offshore lease sale and led negotiations for a major joint venture. This included determination of the relative value of producing properties, stranded gas, and rank exploration leases, including the geologic, geophysical, and political risks inherent in projects on the Alaska North Slope and the Arctic National Wildlife Refuge (ANWR). Other industry responsibilities include Gulf of Mexico exploration, development geology of heavy oil fields in California, technical support for enhanced oil recovery (EOR) projects in the Los Angeles Basin, and divestitures of producing properties in California.

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Adrian Reed has 24 years of energy industry experience, encompassing the upstream oil and gas, electric power, and liquefied natural gas (LNG) sectors, and comprising engineering, planning, finance, trading and marketing, and risk management functions. His experience covers periods of expansion and retrenchment in the United States and the Middle East. He most recently was the chief planning and risk officer at the world's largest LNG producer, located in Doha, Qatar. He led significant company-wide process and performance improvements in the areas of strategic and business planning, risk management, business continuity, and business process redesign.

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