# *Appendix A*

## *Compliance with the Commission's IRP Guidelines*

# 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 08-246, we consider known supply-side and demand-side resources that are expected to become available. We model central-station solar, EE, wind, CCCTs, biomass, and geothermal to meet annual energy needs. For peaking and load following, we model reciprocating engines along with LMS 100, DSG and DR. We also considered, but did not model, next generation nuclear, traditional coal, gasified coal, distributed PV solar, battery storage, pumped hydro, compressed air energy storage, and hydrokinetic energy. We consider development of new transmission capacity and new gas pipeline contracts. | 2, 4, 8 |
| | Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling. | We developed portfolios with resource types which inherently exhibit the characteristics identified in the guideline. Refer to our portfolios composition table in Chapter 9. | 9 |
| | 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. | 4, 8, 9 |
| | The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. | We applied PGE's after tax marginal weighted-average cost of capital of 6.43% as a proxy for the long-term cost of capital in the WECC. | 9 |
| Guideline 1b | Risk and uncertainty must be considered. | | |
| | At a minimum, utilities should address the following sources of risk and uncertainty: | | |

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|---|---|---|---|
| | 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 35 deterministic futures for the economic scenario analysis. Stochastic modeling is used 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, we have a 2020 Oregon $CO_2$ Goal portfolio as well as multiple futures simulating alternative carbon pricing schemes. | 9, 10 |
| | 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. | We identify 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 risk (for wind) by designing multiple futures that stress these variables. Additionally, we created scenarios that combine risk factors: i.e. high carbon costs and high natural gas prices, in order to measure the combined impact on cost and wholesale electricity prices. | 9, 10 |
| 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 customers. | Our IRP Action Plan allows us to continue to serve our customers with a portfolio of resources that provides the best combination of expected costs and associated risks and uncertainties. Our primary tool for examining the mix of expected cost and associated risk was through use of the box-and-whiskers charting. | 10, 12 |

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| | 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. | Consistent with Order 08-246, we plan for the acquisition of major new resources until 2025, hourly dispatch (for variable costs) via Aurora through 2033, and recovery of life-cycle resource investment and fixed costs, including estimated decommissioning. | 8, 9, 10 |
| | 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. | We use expected NPVRR  All other costs over time for gas transport, transmission, fuel, fixed cost recovery, etc. are included within the revenue requirement modeling for all long-lived and short-lived resources. That is, all costs that would actually be incurred to operate the resource are included.  Input assumptions for these costs come from B&V, Wood Mackenzie, EIA, existing contract costs, and other industry sources. | 8, 10 |
| | 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. | We employ the two measures of NPVRR risk for scenario analysis: variability of costs, and severity of outcomes.  We also consider relative likelihood of high or low expected cost. | 10 |
| | 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging. | We include a discussion of traditional physical and financial hedging approaches, their purpose and limitations, for wholesale electricity and for natural gas in Chapter 6. | 6 |
| | The utility should explain in its plan how its resource choices appropriately balance cost and risk. | We explain how we balance cost and risk in Chapter 10 and describe the criteria we use to determine the best cost/risk portfolio. | 10 |
| Guideline 1d | The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | We model a portfolio to achieve the Oregon $CO_2$ goal, RPS compliance in all portfolios, current requirements for non-$CO_2$ and $CO_2$ environmental compliance in all portfolios, and various scenarios for future federal regulation of $CO_2$. | 9, 10 |

| Guideline 2 | Procedural Requirements | PGE Compliance | Chapter |
|---|---|---|---|
| Guideline 2a | The public, which includes other utilities, should be 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. | The public, as represented primarily by a number of stakeholder organizations, has been significantly involved in the development of PGE's IRP. Chapter 1 provides an overview of our public process. Appendix E lists all the presentations of the public process. Public meeting materials and the draft IRP are posted on PGE's website. | 1, Appendix E |
| 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 and comment on November 22, 2013. | 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. | We filed our last IRP in November 2009 and an associated addendum in April 2010. The Commission issued Order No. 10-457 on November 23, 2010, acknowledging PGE's 2009 IRP. PGE filed annual updates in November of 2011 and 2012. On October 3, 2013, the Commission issued Order No. 13-359 authorizing PGE to extend the time to file its next IRP to March 30, 2014. | 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 filing. | N/A to PGE | N/A |
| 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 |

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| 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. | N/A at this time | 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 availability; and | N/A at this time | N/A |
| | 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 comply with this Guideline. We include more detailed descriptions and explanations of how we meet the Commission requirements within the body of the IRP filing. | This Appendix |
| Guideline 4b | b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions; | We include high and low load growth scenarios for PGE in Chapter 3. We also analyze stochastic load risk which is primarily the result of weather variations based on historical observations of pre-schedule vs. actual loads. We use stochastic load risk for the estimate of the reliability of the different portfolios tested in IRP. | 3, 9,10 |
| 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; | We perform three related analyses: 1) A load/resource balance on energy and January and August capacity, 2) a flexible capacity need study; 3) a reliability analysis comparing the performance between portfolios. All portfolios model existing transmission costs from the source to our system. | 3, 5, 8, 9,10, 11 |
| 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 supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources; | N/A to PGE | N/A |

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| Guideline 4e | Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology; | We develop resource-specific life-cycle revenue requirements. We relied on the expertise of an external consultant, Black and Veatch as well as on the results of the 2012 RFPs to estimate costs and advances in technology. | 8, Appendix G |
| Guideline 4f | Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs; | Each portfolio acquires supply and demand resources to a level that maintains, at minimum, a required 6% operating reserve. Using a loss-of-load analysis, we further examine each portfolio for specific performance given its specific incremental resources with associated shaft risks and market exposure. | 9,10 |
| Guideline 4g | Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered; | We base natural gas prices and $CO_2$ price on current third-party outlooks and include a range of higher and lower cost outcomes. | 6, 7, 10 |
| 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; | We use a combination of predominantly single incremental resource and diversified portfolios which acquire various resources in various combinations with varying timing and durations as specified. The portfolios inherently include the considerations described in 4h. | 9, 10 |
| Guideline 4i | Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; | We estimated the expected portfolio cost and a variety of scenario risks, along with reliability and diversity considerations. | 10 |
| Guideline 4j | Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results; | Our results are shown in Chapter 10 and Appendix C. | 10, Appendix C |
| Guideline 4k | Analysis of the uncertainties associated with each portfolio evaluated; | Uncertainties associated with each portfolio are evaluated in Chapter 10. | 10 |

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|---|---|---|---|
| Guideline 4l | Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; | Our IRP Action Plan does not call for large new generation. It does continue existing programs related primarily to the customer side: EE, DR, and DSG. Our preferred portfolio has the best combination of low expected cost and low risk based on using risk metrics required by these guidelines. | 10, 12 |
| 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; | Our preferred portfolio complies with existing state and energy policies and regulations. We include a portfolio based on the Oregon $CO_2$ goal. We show the cost barrier to implementation in Chapter 10. | 10 |
| 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. | Our Action Plan includes activities that we intend to undertake or commit to in the next two to four years. | 12 |

| Guideline 5 | Transmission | PGE Compliance | Chapter |
|---|---|---|---|
| | Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for 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. | Our portfolio analysis includes costs for the fuel transportation and electric transmission required for each resource being considered. We include a portfolio that assumes less costly wind from Montana while adding an estimate of the associated transmission cost. We provide an overview of PGE's transmission strategy in Chapter 11. | 6, 10, 11 |

| 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. | We include the assessment of the Energy Trust of Oregon of technical and achievable potential energy efficiency. | 4 |
| 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. | N/A | N/A |
| 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 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 | We base our portfolios on studies conducted by the ETO which determine the amount of potential energy efficiency without regard to any funding limits. | 4 |
| | Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | Our preferred portfolio and action plan are consistent with the ETO's projection of energy efficiency potential. | 4, 12 |

| 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). | We evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy and capacity needs | 4, 10 |

| 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. | We construct a reference case based on third-party (Wood Mackenzie) analysis of federal legislative $CO_2$ proposals. We assume that compliance comes in the form of a $CO_2$ price, as well as technological standards for new plants. We assume $CO_2$ emissions for PGE are regulated at the point of combustion.<br><br>Our reference case assumes full regulatory compliance for particulates, $SO_X$, $NO_X$, and mercury emissions for all our plants. Potential new portfolio additions are assumed to be in full compliance. | 7, 10 |

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|---|---|---|---|
| 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. | We test our portfolios against futures that incorporate a range of future $CO_2$ prices. | 7, 10 |

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|---|---|---|---|
| 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. | We test the $CO_2$ price which would trigger the selection of our all-green portfolio over our preferred portfolio (which has new gas). | 10 |
| 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. | We include a portfolio in which Boardman and Colstrip no longer dispatch after 2020 and a combination of gas and wind resources replace them. | 9, 10 |

| 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. | We exclude estimated five-year opt-out load based on current customer elections. | 3 |
| **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 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. | We analyze loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy for all of our portfolios. | 9,10 |

| 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. | We evaluate 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 burden central station plants. | 7 |
| **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. | Our acquisition strategy consists primarily of proceeding with demand-side acquisitions and DSG. | 12 |
| | Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. | We provide a discussion of resource ownership relative to power purchase agreements in Chapter 8. | 8 |
| | Identify any Benchmark Resources it plans to consider in competitive bidding. | PGE is not proposing the acquisition of any long-term supply side resource in this IRP. | N/A |
| 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; | We presented this analysis in a technical workshop in 2013 and Chapter 5 was written to specifically address this requirement. | 5 |
| 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 | We presented this analysis in a technical workshop in 2013 and Chapter 5 was written to specifically address this requirement. | 5 |
| 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 | PGE analysis does not identify a gap regarding up-regulation for reliability in the Action Plan time frame. Chapter 8 addresses flexible generating and storage resources. The Action Plan (Chapter 12) calls for additional research preparatory to the next IRP regarding the mix of flexible supply and storage resources. The role of EVs is addressed in Chapter 3. | 8, 12, 3 |

# *Appendix B*

## *PGE Candidate Portfolio Mix*

# Appendix B: Portfolio Details

## Cumulative additions - Energy (MWa)

| | Total MWa in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1. Market** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 116 | 116 | 116 | 116 | 280 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 224 | 247 | 267 | 400 | 417 | 432 | 446 | 461 | 639 |
| **2. Natural Gas** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 116 | 116 | 116 | 116 | 280 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 326 | 653 | 653 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 224 | 247 | 267 | 400 | 743 | 758 | 773 | 1,114 | 1,292 |
| **3. Wind** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 442 | 442 | 442 | 769 | 933 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 224 | 247 | 267 | 400 | 743 | 758 | 773 | 1,114 | 1,292 |
| **4. Diversified Green** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 166 | 466 | 466 | 466 | 466 | 630 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 90 | 90 | 90 | 90 | 110 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 274 | 297 | 317 | 470 | 857 | 872 | 886 | 901 | 1,099 |

# *Appendix B: Portfolio Details*

## Cumulative additions - Energy (MWa)

| | Total MWa in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **5. Diversified Green/EE** | EE (Total) | 35 | 69 | 111 | 140 | 167 | 192 | 215 | 237 | 258 | 278 | 297 | 316 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 160 | 460 | 460 | 460 | 460 | 616 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 90 | 90 | 90 | 90 | 110 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 211 | 290 | 317 | 342 | 495 | 887 | 908 | 928 | 947 | 1,142 |
| **6. Green w/EE and CCCT** | EE (Total) | 35 | 69 | 111 | 140 | 167 | 192 | 215 | 237 | 258 | 278 | 297 | 316 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 160 | 460 | 460 | 460 | 460 | 616 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 90 | 90 | 90 | 90 | 110 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 326 | 326 | 326 | 326 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 211 | 290 | 317 | 342 | 821 | 1,213 | 1,234 | 1,254 | 1,274 | 1,468 |
| **7. Baseload Gas/RPS only** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 116 | 116 | 116 | 116 | 280 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 653 | 653 | 653 | 653 | 653 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 224 | 247 | 593 | 727 | 1,069 | 1,085 | 1,099 | 1,114 | 1,292 |
| **8. Diversified Green with wind MT** | EE (Total) | 35 | 69 | 111 | 140 | 167 | 192 | 215 | 237 | 258 | 278 | 297 | 316 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 17 | 34 | 34 | 144 | 444 | 444 | 444 | 444 | 600 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 59 | 59 | 59 | 59 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 211 | 257 | 301 | 326 | 459 | 840 | 861 | 881 | 901 | 1,075 |

# Appendix B: Portfolio Details

## Cumulative additions - Energy (MWa)

| Total MWa in operation by year (cumulative) | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **9. Diversified balanced wind/CCCT** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 23 | 82 | 82 | 198 | 198 | 198 | 298 | 298 | 462 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 37 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 326 | 326 | 326 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 247 | 329 | 349 | 482 | 825 | 840 | 955 | 969 | 1,185 |
| **10. Diversified Solar/Wind** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 166 | 466 | 466 | 466 | 466 | 630 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 90 | 90 | 90 | 90 | 170 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 274 | 297 | 317 | 470 | 857 | 872 | 886 | 901 | 1,159 |
| **11. Diversified Green with non-CE EE only** | EE (Total) | 35 | 69 | 111 | 140 | 167 | 192 | 215 | 237 | 258 | 278 | 297 | 316 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 166 | 466 | 466 | 466 | 466 | 630 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 90 | 90 | 90 | 90 | 110 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 211 | 290 | 317 | 342 | 501 | 893 | 914 | 934 | 953 | 1,156 |
| **12. Oregon CO2 Goal** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 50 | 50 | 50 | 452 | 752 | 752 | 752 | 752 | 915 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 70 | 70 | 150 | 150 | 150 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 326 | 326 | 326 | 326 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | -612 | -256 | -256 | -256 | -256 | -256 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 274 | 297 | 317 | 450 | 1,193 | 1,208 | 1,302 | 1,317 | 1,495 |

# Appendix B: Portfolio Details

## Cumulative additions - Energy (MWa)

| | Total MWa in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **13. Baseload renewables** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 116 | 116 | 116 | 116 | 280 |
| | Other Renewables | 0 | 0 | 0 | 50 | 50 | 50 | 70 | 440 | 440 | 440 | 440 | 460 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 274 | 297 | 317 | 470 | 857 | 872 | 886 | 901 | 1,099 |

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **14. High Solar** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 116 | 116 | 116 | 116 | 116 | 280 |
| | Other Renewables | 0 | 0 | 0 | 50 | 50 | 50 | 70 | 440 | 440 | 440 | 440 | 520 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 274 | 297 | 317 | 470 | 857 | 872 | 886 | 901 | 1,159 |

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **15. Defer RPS Physical Compliance** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 23 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 362 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 37 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 326 | 326 | 326 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 247 | 329 | 349 | 366 | 709 | 724 | 739 | 753 | 1,085 |

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **16. Diversified Baseload Gas/Wind** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 23 | 82 | 82 | 198 | 198 | 198 | 298 | 298 | 462 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 37 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 326 | 326 | 653 | 653 | 653 | 653 | 653 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 247 | 329 | 675 | 809 | 1,151 | 1,167 | 1,281 | 1,296 | 1,511 |

# Appendix B: Portfolio Details

## Cumulative additions - Energy (MWa)

| | Total MWa in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **17. Wind Energy Only** | EE (Total) | 35 | 69 | 99 | 124 | 147 | 167 | 184 | 201 | 216 | 230 | 245 | 259 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 50 | 166 | 496 | 556 | 556 | 556 | 720 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 199 | 224 | 247 | 317 | 450 | 797 | 872 | 886 | 901 | 1,079 |
| **18. Wind Energy w/ EE** | EE (Total) | 35 | 69 | 111 | 140 | 167 | 192 | 215 | 237 | 258 | 278 | 297 | 316 |
| | DSG/DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 25 | 135 | 460 | 515 | 515 | 515 | 671 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 0 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | 35 | 169 | 211 | 240 | 267 | 317 | 450 | 797 | 873 | 893 | 912 | 1,087 |

# *Appendix B: Portfolio Details*

## Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

| | Total MW in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1. Market** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 43 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 0 | 0 | 0 | 0 | 97 | 97 | 97 | 97 | 97 | 227 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 436 | 425 | 472 | 694 | 731 | 1,130 | 1,252 | 1,303 | 1,337 | 1,226 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **2. Natural Gas** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 43 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 395 | 790 | 790 |
| | Peakers (modeled as gas) | 0 | 0 | 125 | 125 | 171 | 475 | 475 | 629 | 749 | 749 | 749 | 749 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | Mid term / ST procurement reserve | 450 | 450 | 312 | 300 | 300 | 219 | 353 | 204 | 205 | 256 | -105 | -86 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **3. Wind** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 68 | 68 | 68 | 118 | 144 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 125 | 125 | 171 | 475 | 576 | 973 | 1,094 | 1,094 | 1,100 | 1,153 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 312 | 300 | 300 | 219 | 252 | 204 | 205 | 256 | 234 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **4. Diversified Green** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 26 | 72 | 72 | 72 | 72 | 97 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 84 | 84 | 84 | 84 | 89 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 117 | 117 | 164 | 444 | 488 | 886 | 1,006 | 1,055 | 1,059 | 1,111 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 319 | 300 | 300 | 242 | 309 | 204 | 205 | 207 | 238 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |

# Appendix B: Portfolio Details

## Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

| | Total MW in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **5. Diversified Green/EE** | EE (Total) | 48 | 93 | 143 | 178 | 209 | 237 | 262 | 287 | 310 | 332 | 355 | 377 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 25 | 71 | 71 | 71 | 71 | 95 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 84 | 84 | 84 | 84 | 89 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 97 | 97 | 131 | 406 | 443 | 833 | 947 | 989 | 989 | 1,040 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 325 | 300 | 306 | 248 | 317 | 211 | 212 | 214 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **6. Green w/EE and CCCT** | EE (Total) | 48 | 93 | 143 | 178 | 209 | 237 | 262 | 287 | 310 | 332 | 355 | 377 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 25 | 71 | 71 | 71 | 71 | 95 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 84 | 84 | 84 | 84 | 89 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 395 | 395 | 395 | 395 |
| | Peakers (modeled as gas) | 0 | 0 | 97 | 97 | 131 | 131 | 131 | 438 | 552 | 594 | 594 | 645 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 325 | 300 | 306 | 523 | 233 | 211 | 212 | 214 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **7. Baseload Gas/RPS only** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 43 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 790 | 790 | 790 | 790 | 790 |
| | Peakers (modeled as gas) | 0 | 0 | 125 | 125 | 125 | 125 | 125 | 234 | 354 | 403 | 411 | 463 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 312 | 300 | 347 | 174 | 308 | 204 | 205 | 207 | 234 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **8. Diversified Green with wind MT** | EE (Total) | 48 | 93 | 143 | 178 | 209 | 237 | 262 | 287 | 310 | 332 | 355 | 377 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 3 | 5 | 5 | 22 | 64 | 64 | 64 | 64 | 88 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 49 | 49 | 49 | 49 | 49 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 102 | 102 | 134 | 432 | 483 | 874 | 988 | 1,030 | 1,033 | 1,085 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 320 | 300 | 306 | 225 | 301 | 211 | 212 | 214 | 239 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |

# Appendix B: Portfolio Details

## Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

| | Total MW in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **9. Diversified balanced wind/CCCT** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 4 | 13 | 13 | 30 | 30 | 30 | 46 | 46 | 71 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 24 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 395 | 395 | 395 |
| | Peakers (modeled as gas) | 0 | 0 | 121 | 121 | 159 | 463 | 463 | 616 | 721 | 770 | 770 | 806 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 315 | 300 | 300 | 219 | 353 | 204 | 221 | 207 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **10. Diversified Solar/Wind** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 26 | 72 | 72 | 72 | 72 | 97 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 20 | 20 | 20 | 20 | 39 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 117 | 117 | 164 | 463 | 552 | 949 | 1,070 | 1,118 | 1,118 | 1,161 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 319 | 300 | 300 | 223 | 264 | 204 | 205 | 207 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **11. Diversified Green with non-CE EE only** | EE (Total) | 48 | 93 | 143 | 178 | 209 | 237 | 262 | 287 | 310 | 332 | 355 | 377 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 26 | 72 | 72 | 72 | 72 | 97 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 84 | 84 | 84 | 84 | 89 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 117 | 117 | 164 | 444 | 488 | 886 | 1,006 | 1,055 | 1,059 | 1,111 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 305 | 280 | 274 | 210 | 270 | 157 | 151 | 147 | 171 | 127 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **12. Oregon CO2 Goal** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 8 | 8 | 8 | 69 | 112 | 112 | 112 | 112 | 137 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 16 | 16 | 34 | 34 | 34 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 395 | 395 | 395 | 395 |
| | Peakers (modeled as gas) | 0 | 0 | 117 | 117 | 164 | 489 | 839 | 839 | 917 | 966 | 974 | 1,026 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | -670 | -296 | -296 | -296 | -296 | -296 |
| | Mid term / ST procurement reserve | 450 | 450 | 319 | 300 | 300 | 198 | 213 | 180 | 223 | 207 | 234 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |

# Appendix B: Portfolio Details

## Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

| | Total MW in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **13. Baseload renewables** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 43 |
| | Other Renewables | 0 | 0 | 0 | 56 | 56 | 56 | 79 | 481 | 481 | 481 | 481 | 486 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 68 | 68 | 115 | 396 | 396 | 542 | 663 | 711 | 715 | 767 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 368 | 300 | 300 | 242 | 353 | 204 | 205 | 207 | 238 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **14. High Solar** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 43 |
| | Other Renewables | 0 | 0 | 0 | 11 | 11 | 11 | 16 | 100 | 100 | 100 | 100 | 118 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 114 | 114 | 160 | 459 | 526 | 924 | 1,044 | 1,093 | 1,093 | 1,135 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 323 | 300 | 300 | 223 | 286 | 204 | 205 | 207 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **15. Defer RPS Physical Compliance** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 4 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 56 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 24 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 395 | 395 | 395 |
| | Peakers (modeled as gas) | 0 | 0 | 121 | 121 | 159 | 480 | 480 | 634 | 754 | 803 | 803 | 822 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 315 | 300 | 300 | 201 | 353 | 204 | 205 | 207 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **16. Diversified Baseload Gas/Wind** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 4 | 13 | 13 | 30 | 30 | 30 | 46 | 46 | 71 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 24 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 395 | 395 | 790 | 790 | 790 | 790 | 790 |
| | Peakers (modeled as gas) | 0 | 0 | 121 | 121 | 121 | 121 | 121 | 221 | 326 | 375 | 375 | 411 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 315 | 300 | 338 | 165 | 299 | 204 | 221 | 207 | 242 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |

# Appendix B: Portfolio Details

## Cumulative additions - Capacity (MW) (Usable Capacity for renewables)

| | Total MW in operation by year (cumulative) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **17. Wind Energy Only** | EE (Total) | 48 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 | 288 | 304 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 8 | 26 | 76 | 86 | 86 | 86 | 111 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 125 | 125 | 164 | 467 | 568 | 956 | 1,076 | 1,125 | 1,133 | 1,186 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 312 | 300 | 308 | 219 | 253 | 213 | 205 | 207 | 234 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |
| **18. Wind Energy w/ EE** | EE (Total) | 48 | 93 | 143 | 178 | 209 | 237 | 262 | 287 | 310 | 332 | 355 | 377 |
| | DSG/DR | 43 | 43 | 56 | 68 | 75 | 75 | 77 | 79 | 83 | 88 | 95 | 103 |
| | Wind | 0 | 0 | 0 | 0 | 0 | 4 | 21 | 71 | 79 | 79 | 79 | 103 |
| | Other Renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Baseload Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Peakers (modeled as gas) | 0 | 0 | 105 | 105 | 135 | 433 | 527 | 909 | 1,022 | 1,065 | 1,068 | 1,120 |
| | Exising Plants Changes | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Mid term / ST procurement reserve | 450 | 450 | 317 | 300 | 310 | 225 | 260 | 219 | 212 | 214 | 239 | 200 |
| | | 540 | 585 | 621 | 650 | 730 | 974 | 1,146 | 1,564 | 1,706 | 1,778 | 1,835 | 1,903 |

# *Appendix C*

## *PGE Candidate Portfolio Analysis Results*

# Appendix C: Candidate Portfolio Analysis Results

Table C-1 below shows the results of our Scenario analysis. We calculate the expected Net Present Value of Revenue Requirement (NPVRR) from 2013 to 2033 for each of the 18 Portfolios under each of the 36 Futures.

**Table C-1: Portfolio Scenario Analysis Detail ($ Million)**

**2013 IRP - Portfolio Results - DRAFT filing Nov.2013**

NPVRR, 2013$ million

| Portfolios → | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| Futures ↓ | Market w/ Physical RPS | Natural Gas | Wind | Diversified Green | Diversified Green/EE | Green w/EE and CCCT | Baseload Gas/RPS only | Diversified Green with wind MT | Diversified balanced wind/CCCT |
| **Reference Case** | | | | | | | | | |
| 1 Reference Case | 16,243 | 17,840 | 18,999 | 19,053 | 19,315 | 18,959 | 17,397 | 19,286 | 18,206 |
| **Fuel/$CO_2$** | | | | | | | | | |
| 2 High Gas | 17,327 | 18,877 | 19,758 | 19,868 | 20,089 | 19,716 | 18,427 | 20,100 | 19,144 |
| 3 Low Gas | 14,886 | 16,512 | 18,018 | 18,001 | 18,313 | 17,971 | 16,076 | 18,239 | 17,007 |
| 4 High Coal | 16,531 | 18,095 | 19,248 | 19,309 | 19,568 | 19,202 | 17,654 | 19,543 | 18,464 |
| 5 Low Coal | 16,092 | 17,691 | 18,855 | 18,907 | 19,170 | 18,815 | 17,248 | 19,141 | 18,059 |
| 12 No Carbon Tax | 15,369 | 16,984 | 18,369 | 18,352 | 18,646 | 18,298 | 16,541 | 18,592 | 17,424 |
| 13 Synapse low CO2 | 16,812 | 18,388 | 19,453 | 19,517 | 19,766 | 19,400 | 17,942 | 19,752 | 18,723 |
| 14 Synapse High CO2 | 18,927 | 20,326 | 20,879 | 21,097 | 21,268 | 20,850 | 19,881 | 21,318 | 20,506 |
| 25 High Gas and CO2 | 20,104 | 21,506 | 21,773 | 22,048 | 22,178 | 21,758 | 21,059 | 22,267 | 21,582 |
| 26 Low Gas and No CO2 | 14,003 | 15,691 | 17,426 | 17,330 | 17,677 | 17,352 | 15,251 | 17,575 | 16,255 |
| 30 CO2 trigger | 22,059 | 23,125 | 22,649 | 23,260 | 23,274 | 22,792 | 22,722 | 23,438 | 23,001 |
| 31 Very High Gas | 18,971 | 20,415 | 20,819 | 21,052 | 21,205 | 20,801 | 19,964 | 21,277 | 20,520 |
| 33 16 dollars CO2 in 2023 | 16,115 | 17,717 | 18,908 | 18,950 | 19,218 | 18,864 | 17,274 | 19,186 | 18,093 |
| **Load** | | | | | | | | | |
| 6 Hi load test 1 std dev | 17,209 | 18,805 | 19,964 | 20,018 | 20,280 | 19,925 | 18,362 | 20,252 | 19,172 |
| 7 Low load test 1 std dev | 15,280 | 16,876 | 18,035 | 18,089 | 18,351 | 17,996 | 16,433 | 18,323 | 17,242 |
| 8 Hi load test 2 std dev | 18,313 | 19,909 | 21,068 | 21,122 | 21,384 | 21,029 | 19,466 | 21,356 | 20,275 |
| 9 Low load test 2 std dev | 14,284 | 15,880 | 17,039 | 17,093 | 17,355 | 17,000 | 15,437 | 17,327 | 16,246 |
| 24 Solar PV Penetration | 16,165 | 17,762 | 18,921 | 18,974 | 19,237 | 18,881 | 17,319 | 19,208 | 18,128 |
| 28 Max PGE Opt Outs | 15,600 | 17,196 | 18,356 | 18,409 | 18,672 | 18,316 | 16,754 | 18,643 | 17,563 |
| **Hydro** | | | | | | | | | |
| 10 High Hydro | 15,723 | 17,500 | 18,697 | 18,719 | 19,001 | 18,712 | 17,071 | 18,957 | 17,869 |
| 11 Low Hydro | 16,627 | 17,986 | 19,080 | 19,179 | 19,427 | 19,013 | 17,543 | 19,423 | 18,349 |
| **Capital Cost** | | | | | | | | | |
| 17 High Capital Cost Gas Thermal | 16,265 | 18,001 | 19,142 | 19,188 | 19,441 | 19,074 | 17,532 | 19,418 | 18,345 |
| 18 High Capital Cost Wind and Solar | 16,462 | 18,058 | 19,715 | 19,624 | 19,875 | 19,519 | 17,616 | 19,834 | 18,604 |
| 19 High Capital Cost | 16,484 | 18,220 | 19,858 | 19,813 | 20,054 | 19,688 | 17,751 | 19,999 | 18,750 |
| 20 Low Capital Cost | 16,041 | 17,497 | 18,430 | 18,497 | 18,775 | 18,430 | 17,081 | 18,790 | 17,786 |
| 21 No PTC and ITC | 16,397 | 17,993 | 19,545 | 19,733 | 19,987 | 19,632 | 17,551 | 19,891 | 18,494 |
| 27 Low Capital Cost Wind and Solar | 16,135 | 17,732 | 18,646 | 18,759 | 19,027 | 18,672 | 17,289 | 19,027 | 18,005 |
| 34 High Capital Cost Wind and Solar/No CO2 | 15,588 | 17,203 | 19,085 | 18,924 | 19,206 | 18,858 | 16,760 | 19,139 | 17,823 |
| 35 22 yr life for wind | 16,717 | 18,313 | 20,546 | 20,223 | 20,460 | 20,105 | 17,871 | 20,408 | 19,047 |
| 36 32 yr life for wind | 16,146 | 17,743 | 18,685 | 18,827 | 19,094 | 18,739 | 17,300 | 19,059 | 18,035 |
| **Power Prices** | | | | | | | | | |
| 15 High Electricity Prices | 16,935 | 16,740 | 17,485 | 17,801 | 18,043 | 17,608 | 16,554 | 18,108 | 17,170 |
| 16 Low Electricity Prices | 16,037 | 17,798 | 18,966 | 18,997 | 19,276 | 18,969 | 17,355 | 19,243 | 18,152 |
| 29 Perfect Storm | 23,139 | 18,505 | 17,924 | 18,841 | 18,871 | 18,339 | 19,036 | 19,004 | 18,980 |
| 32 High Electricity Prices w/freeriders | 16,833 | 15,503 | 16,003 | 16,353 | 16,620 | 16,205 | 15,393 | 16,709 | 15,890 |
| **Wind CF** | | | | | | | | | |
| 22 PGE Wind High CF | 16,164 | 17,760 | 18,737 | 18,857 | 19,124 | 18,768 | 17,317 | 19,150 | 18,067 |
| 23 PGE Wind Low CF | 16,324 | 17,920 | 19,262 | 19,250 | 19,508 | 19,152 | 17,477 | 19,424 | 18,347 |

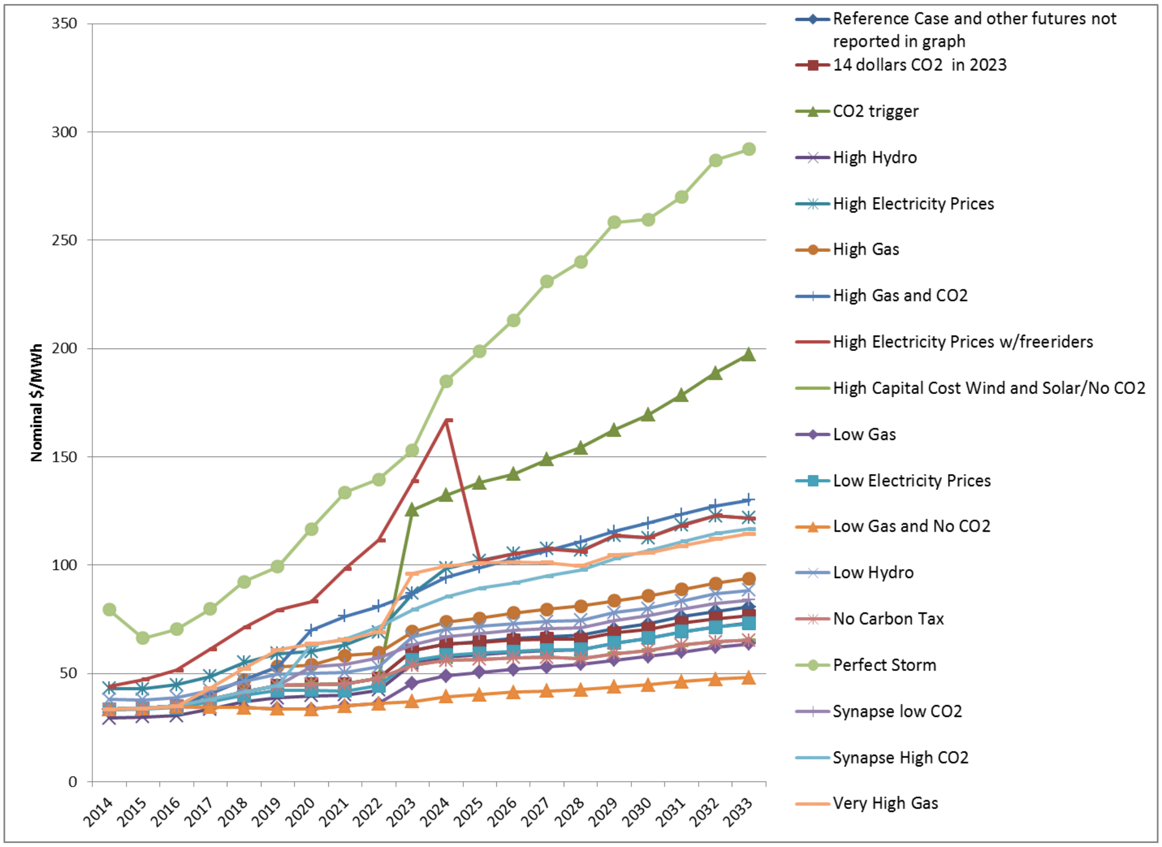
**2013 IRP - Portfolio Results - DRAFT filing Nov.2013**
NPVRR, 2013$ million

| Portfolios → / Futures ↓ | 10 Diversified Solar/Wind | 11 Diversified Green with non-CE EE only | 12 Oregon CO2 Goal | 13 Baseload Renewables | 14 High Solar | 15 Defer RPS Physical Compliance | 16 Diversified Baseload Gas/Wind | 17 Wind Energy Only | 18 Wind Energy w/ EE |
|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | | | | | | | | | |
| 1 Reference Case | 19,283 | 19,472 | 20,430 | 20,354 | 20,711 | 18,024 | 17,865 | 18,616 | 18,826 |
| **Fuel/$CO_2$** | | | | | | | | | |
| 2 High Gas | 20,068 | 20,238 | 21,211 | 21,200 | 21,487 | 19,034 | 18,783 | 19,440 | 19,630 |
| 3 Low Gas | 18,264 | 18,481 | 19,415 | 19,272 | 19,698 | 16,736 | 16,682 | 17,555 | 17,790 |
| 4 High Coal | 19,536 | 19,725 | 20,472 | 20,617 | 20,966 | 18,287 | 18,112 | 18,872 | 19,081 |
| 5 Low Coal | 19,138 | 19,328 | 20,398 | 20,207 | 20,565 | 17,875 | 17,717 | 18,470 | 18,681 |
| 12 No Carbon Tax | 18,603 | 18,810 | 20,012 | 19,630 | 20,022 | 17,195 | 17,091 | 17,914 | 18,142 |
| 13 Synapse low CO2 | 19,739 | 19,920 | 20,699 | 20,833 | 21,173 | 18,573 | 18,371 | 19,082 | 19,287 |
| 14 Synapse High CO2 | 21,259 | 21,402 | 21,634 | 22,491 | 22,699 | 20,485 | 20,102 | 20,665 | 20,829 |
| 25 High Gas and CO2 | 22,186 | 22,306 | 22,461 | 23,464 | 23,629 | 21,627 | 21,174 | 21,623 | 21,768 |
| 26 Low Gas and No CO2 | 17,620 | 17,853 | 19,046 | 18,570 | 19,051 | 15,933 | 15,947 | 16,884 | 17,139 |
| 30 CO2 trigger | 23,292 | 23,369 | 23,169 | 24,783 | 24,713 | 23,195 | 22,532 | 22,831 | 22,900 |
| 31 Very High Gas | 21,200 | 21,339 | 22,300 | 22,446 | 22,614 | 20,537 | 20,124 | 20,628 | 20,786 |
| 33 16 dollars CO2 in 2023 | 19,184 | 19,376 | 20,370 | 20,248 | 20,612 | 17,905 | 17,754 | 18,513 | 18,726 |
| **Load** | | | | | | | | | |
| 6 Hi load test 1 std dev | 20,248 | 20,438 | 21,395 | 21,319 | 21,677 | 18,989 | 18,830 | 19,581 | 19,791 |
| 7 Low load test 1 std dev | 18,319 | 18,509 | 19,466 | 19,390 | 19,748 | 17,060 | 16,901 | 17,652 | 17,862 |
| 8 Hi load test 2 std dev | 21,352 | 21,542 | 22,499 | 22,423 | 22,781 | 20,093 | 19,934 | 20,685 | 20,895 |
| 9 Low load test 2 std dev | 17,323 | 17,513 | 18,470 | 18,394 | 18,752 | 16,064 | 15,905 | 16,656 | 16,866 |
| 24 Solar PV Penetration | 19,205 | 19,394 | 20,352 | 20,276 | 20,633 | 17,945 | 17,787 | 18,538 | 18,748 |
| 28 Max PGE Opt Outs | 18,639 | 18,829 | 19,787 | 19,711 | 20,068 | 17,380 | 17,222 | 17,972 | 18,182 |
| **Hydro** | | | | | | | | | |
| 10 High Hydro | 18,967 | 19,167 | 20,200 | 19,983 | 20,389 | 17,647 | 17,600 | 18,282 | 18,500 |
| 11 Low Hydro | 19,387 | 19,571 | 20,432 | 20,551 | 20,830 | 18,211 | 17,942 | 18,736 | 18,945 |
| **Capital Cost** | | | | | | | | | |
| 17 High Capital Cost Gas Thermal | 19,425 | 19,608 | 20,601 | 20,447 | 20,850 | 18,165 | 17,995 | 18,761 | 18,962 |
| 18 High Capital Cost Wind and Solar | 19,932 | 20,044 | 21,373 | 20,596 | 21,284 | 18,302 | 18,263 | 19,229 | 19,392 |
| 19 High Capital Cost | 20,074 | 20,233 | 21,544 | 21,015 | 21,423 | 18,450 | 18,400 | 19,374 | 19,528 |
| 20 Low Capital Cost | 18,696 | 18,917 | 19,690 | 19,731 | 20,037 | 17,660 | 17,453 | 18,095 | 18,337 |
| 21 No PTC and ITC | 19,929 | 20,153 | 21,444 | 20,954 | 21,094 | 18,157 | 18,152 | 19,304 | 19,458 |
| 27 Low Capital Cost Wind and Solar | 18,912 | 19,179 | 19,935 | 20,223 | 20,249 | 17,882 | 17,663 | 18,313 | 18,547 |
| 34 High Capital Cost Wind and Solar/No CO2 | 19,252 | 19,381 | 20,955 | 19,872 | 20,595 | 17,474 | 17,489 | 18,528 | 18,709 |
| 35 22 yr life for wind | 20,454 | 20,643 | 22,214 | 20,828 | 21,185 | 18,610 | 18,706 | 19,923 | 20,032 |
| 36 32 yr life for wind | 19,057 | 19,247 | 20,080 | 20,257 | 20,614 | 17,900 | 17,693 | 18,365 | 18,594 |
| **Power Prices** | | | | | | | | | |
| 15 High Electricity Prices | 17,844 | 18,084 | 18,580 | 19,605 | 19,200 | 17,174 | 16,729 | 17,303 | 17,547 |
| 16 Low Electricity Prices | 19,244 | 19,440 | 20,449 | 20,285 | 20,696 | 17,946 | 17,863 | 18,556 | 18,776 |
| 29 Perfect Storm | 18,336 | 18,604 | 16,386 | 21,635 | 19,177 | 19,478 | 18,392 | 18,291 | 18,472 |
| 32 High Electricity Prices w/freeriders | 16,305 | 16,584 | 16,758 | 18,490 | 17,563 | 16,033 | 15,439 | 15,807 | 16,106 |
| **Wind CF** | | | | | | | | | |
| 22 PGE Wind High CF | 19,087 | 19,277 | 20,183 | 20,275 | 20,632 | 17,926 | 17,725 | 18,395 | 18,622 |
| 23 PGE Wind Low CF | 19,480 | 19,670 | 20,677 | 20,435 | 20,794 | 18,122 | 18,005 | 18,837 | 19,031 |

Figure C-1 shows the electricity prices for the Pacific Northwest generated in the different futures and highlights their wide range. Aurora generates a different set of electricity prices for the WECC for the different futures described in Chapter 9 of the IRP.

Several futures, and therefore prices, are intentionally extreme in order to capture the risk embedded in futures different from our reference case.

**Figure C-1: PNW Wholesale Electricity Price by Future**



# *Appendix D*

## *PGE Wind Integration Study Phase 4*

# I. Executive Summary: Wind Integration Study Phase 4

In 2007, given projections for a significant increase in wind generating resources, Portland General Electric (PGE) began efforts to forecast costs associated with self-integration of wind generation. This effort entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming (MIP). This study was intended as 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 participation from EnerNex (a leading resource for electric power research, plus engineering and consulting services to government, utilities, industry, and private institutions), who provided input data and guidance for Phase 1. A significant driver of Phase 2 was the expectation that the cost for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources. In addition, it is PGE's contention that BPA's variable energy services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in Phase 2.

In the interim between Phase 2 and Phase 4, PGE conducted a Phase 3 internal study to inform the decision for the BPA FY 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.

A significant goal for Phase 4 of the Wind Integration Study was to include additional refinements (some of the enhancements were suggested in the "Next Steps" section of Phase 2) for estimating PGE's additional system operating costs incurred by the self-integration of its wind resources and to determine the sensitivity of the wind integration cost to gas price variability. As in Phases 1-3 of the Wind Integration Study, the Phase 4 effort has also included seeking input, deliverables, and feedback from a Technical Review Committee (TRC) and other external consultants. Since launching Phase 4, PGE has reprogrammed and refined the wind integration model, updated the study, and also held a public methodological workshop to discuss progress and modeling details. The public methodological workshop was attended by staff from the Oregon Public Utility Commission (OPUC), the Oregon Department of Energy (ODOE) and other interested parties that have participated in PGE's 2013 Integrated Resource Planning proceeding (IRP – OPUC Docket No. LC 56). In addition to this public review, the Phase 4 data and methodology have been carefully evaluated by the TRC, who provided valuable insight and information associated with wind integration modeling.

The Phase 4 model employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS) programming and a Gurobi optimizer. The Phase 4 model incorporates the improvements made in Phase 2 including:

- Three-stage scheduling optimization with separate Day-Ahead, Hour-Ahead, and Within-Hour calculations;
- Refined estimates of PGE's reserve requirements.

The additional model improvements incorporated in Phase 4 include:

- Separate increasing ("INC") and decreasing ("DEC") reserve requirement formulations for regulation, load following and imbalance reserves;
- 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.

The results of the study indicate that PGE's estimated self-integration costs (in 2018$) at the reference gas price case is $3.99 per MWh, the high gas price case is $4.24 per MWh, and the low gas price case is $3.57 per MWh. These prices fall within the range calculated by other utilities in the region. **Note: PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources.** Specific model assumptions are detailed below but, in short, reflect a potential 2018 state in which PGE seeks to integrate almost 717 MW of wind (to physically meet the 2015 Oregon RPS requirement) using existing PGE resources, and future balancing resources acquired in the 2011 RFP, subject to associated operating limitations. As the supply of variable energy resources and the associated demand for flexible balancing resources increases over time, subsequent phases of the Wind Integration Study will assess the effects of these changes.

# II. INTRODUCTION

## *i. REASONS FOR THE PHASE 4 WIND INTEGRATION STUDY*

Since the Phase 2 Study, there have been significant changes in the capabilities and inputs to the model. The additional capabilities of the PGE Wind Integration Model were developed in response to public suggestion and internal requests. In addition, gas prices fell off dramatically due to the increased availability of shale gas. As a result of the 2011 RFP process PGE added 266.5 MW at Tucannon River Wind Project, 220 MW flexible gas generators, Port Westward 2, and 440 MW baseload combined cycle gas generator at the Carty Reservoir site. In 2018, PGE loses some of its most flexible capacity on its system with the falling off of some Mid-C contracts. Given the aforementioned changes, it seemed appropriate to update the Phase 2 Study.

### *ii. STUDY ASSUMPTIONS*

Phase 4 of the Wind Integration Study is based on existing PGE owned and contracted resources (as of 2018) plus the 2011 RFP resources which are all planned to be commercially available by 2018. By 2018, PGE will have a varied mix of generation consisting of 2,496 MW of thermal generation (670 MW coal-fired and 1,826 MW gas-fired), 489 MW of PGE-owned hydro generation, approximately 147 MW of long-term hydro power purchase agreements, and 817 MW of wind generation. (One-hundred MW of the wind plant receives long-term third-party wind integration and is not included for this study.) Because PGE is currently a "short" utility, the remainder of its load is covered by market transactions – term contracts and spot market purchases.

Additional assumptions within the model include:

- 2018 is the Wind Integration Study year.
- 2005 actual data was used for hydro flows, wind generation, and load forecast errors.
- 2018 Mid-Columbia (Mid-C) electricity market prices (as used for economic dispatch in the wind integration model) were simulated with AURORAxmp. This is the model used in the Integrated Resource Plan (as discussed in Section 5.3.2, below.
- PGE's 450 MW Biglow Canyon Wind Farm, located in Sherman County, Oregon, is self-integrated.
- PGE's 266.5 MW of Tucannon River Wind Project, located in Columbia County, Washington, is self-integrated.

PGE resources available to provide ancillary services:

- PGE's contractual share of Mid-Columbia hydro generation, which diminishes over time;
- Two-thirds of Pelton-Round Butte hydro generation
- Beaver gas-powered generation, in both combined cycle and simple cycle modes.
- Coyote Springs gas-powered generation
- Port Westward 2 gas-powered generation

PGE resources not available to provide ancillary services:

- Port Westward gas-powered generation
- Carty gas-powered generation
- Boardman coal-powered generation
- Colstrip coal-powered generation

Specific details of PGE's resources and their effective uses for ancillary services are provided in Section V.iv, below.

In Section III of this report, we summarize the public process and third-party review undertaken to ensure that PGE has accomplished its goal of developing an accurate representation of its potential for self-integration using base-line assumptions and robust modeling techniques. In Section IV, we describe the regional wind characteristics used to establish PGE's integration requirements during Day-Ahead, Hour-Ahead, and Within-Hour time frames. In Section V, we provide a detailed description of PGE's wind integration methodology including the programming tools, data assumptions, modeling approach, and calculations for reserves and other variables. In Section VI, we provide a summary of the results and conclusions of our findings. Section VII provides appendices of supporting detail and documentation.

# III. PUBLIC PROCESS AND REVIEWS

As with Phase 2 of the Wind Integration Study, Phase 4 sought to assure a robust review by external parties of the logic, assumptions, and data within the model to ensure their accuracy and thereby comply with the Commission directive to have a "wind integration study that has been vetted by regional stakeholders." (Commission Order No. 10-457). To achieve this, several groups were invited to participate in PGE's efforts.

### *iii. TECHNICAL REVIEW COMMITTEE (TRC)*

PGE's TRC consisted of the following members:

- J. Charles Smith, Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Michael Milligan, Ph.D., Principal Analyst, National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E., Consultant with NREL
- Michael Goggin, Manager of Transmission Policy, American Wind Energy Association (AWEA)
- Bob Zavadil, E.E., Executive VP of Power Systems Consulting, EnerNex Corporation

The constitution, functions and requirements of the TRC were determined in accordance with UVIG's "Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems" as provided in Appendix A.

In accordance with UWIG's TRC Principles agreement, PGE's TRC, in a joint letter displayed in Attachment 1, "endorses the study methodology, execution, and this final report" of PGE's Phase 4 Wind Integration Study.

### *iv. PROGRAMMING CONSULTANTS*

In Phase 4, PGE employed one outside subject matter expert, Jennifer Hodgdon, Ph.D, to assist in the enhancement of the mixed integer programming (MIP) based optimization model that PGE used to calculate costs associated with integrating wind into the PGE system. Dr. Hodgdon helped develop and implement the GAMS and Visual Basic utilized in enhancing the capabilities of the model developed in Phase 2.

Jennifer Hodgdon is owner and Principal Consultant for Poplar ProductivityWare, Seattle and Spokane, WA. She received her Ph.D. degree from Cornell in 1993 and has more than fifteen years of experience as a professional software developer, using a variety of languages and operating systems for many different applications and in various industries.

### *v. PUBLIC MEETINGS*

PGE held two public regional stakeholder meetings in which all members of the service list from PGE's 2013 IRP (OPUC docket LC 56) were invited to attend and provided the opportunity to examine in detail, the methodology of the study and the results. The meetings were held on August 8 and August 29, 2013, and attended by OPUC staff and other interested parties.

During these meetings, PGE provided detailed explanations of the enhancements to the modeling approach, methodology, data inputs, assumptions, bases for cost breakdowns and reserves, and the actual integration costs. PGE also answered numerous questions and engaged in extensive discussion regarding details of the Wind Integration Study.

## IV. WIND INTEGRATION ISSUES & METHODOLOGY – OVERVIEW

### *i. WIND DATA SOURCE*

The development of wind power capacity factors and shapes representative of wind generation operations was established initially by using the NREL Western Wind Resource Database (WWRD). The database is a result of 3TIER Group's modeling of wind resources across the entire western United States to generate a consistent wind dataset at a 2-km, 10-minute resolution based on actual wind measurements for the years 2004, 2005 and 2006. The NREL database converted wind to power based on the power curve for Vestas V90 3 MW (Biglow Phase 1), Siemens 141 SWT 2.3 MW turbines (Biglow Phase 2 and 3), and Siemens 108 SWT 2.3 MW turbines (Tucannon River).

The WWRD database provided the following wind data for the study:

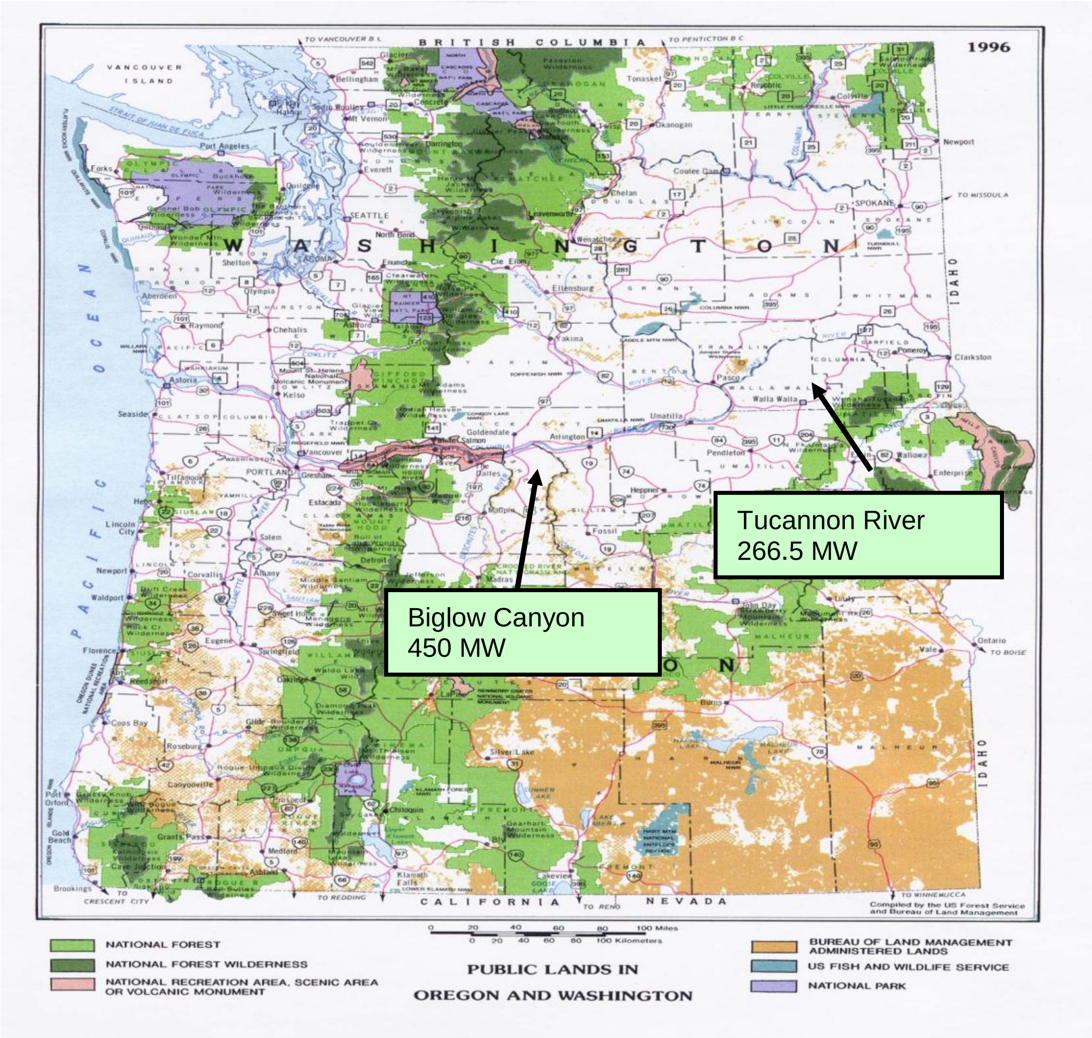
- Date and time (mm/dd/yyyy hh:mm:ss.sss)[1]
- Wind speed (mph)
- Actual wind power output in MW at 1 minute and 10 minute intervals
- Day-Ahead forecast power in MW at 1 hour intervals
- Years 2004, 2005 and 2006

[1] The time stamp hh:mm:ss.sss conveys hours, minutes, seconds and fractional seconds.

- Site Id
- Site location (Longitude, Latitude)

### *ii. WIND SITE POWER OUTPUT*

Virtual wind farms of 266.5 MW in Columbia County on the Tucannon River site and 450 MW in Sherman County on the Biglow Canyon site (see Figure 1, below) in the Columbia River Gorge were developed by selecting multiple wind sites and aggregating the wind site outputs from the NREL database. Capacity factors for the 266.5 MW and 450 MW wind farms based on the 2005 NREL data were 34.4% and 29.6%, respectively.



### *iii.* *WIND SITE FORECASTS*

PGE methodology for performing forecasts is unchanged from the Phase 2 study[2].

## V. WIND INTEGRATION METHODOLOGY

### *i.* *OVERVIEW*

Phase 4 of the Wind Integration Study seeks to determine the effect on system operating costs resulting from the introduction of wind resources on PGE's system; specifically, of PGE employing its own generating resources to integrate 716.5 MW of wind capacity in 2018. The system operating costs of wind integration at different gas price levels are calculated by modeling total system costs with and without the additional reserve requirements due to wind. The costs of wind integration in this study are measured as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. The cost savings are conditional on the ability of a given set of generation resources to adjust for the variability and uncertainty of wind generation. In the remaining sections of this chapter, we will discuss:

- The need for Dynamic Capacity in PGE's portfolio (Section V.ii.)
- The modeling tools used by PGE in implementing the study (Section V.iii.)
- Data sources, data generation, and modeling assumptions (Section V.iv.)
- The logic and structure of the modeling approach (Section V.v.)
- Methods for calculating incremental reserves for integrating wind (Section V.vi.)

### *ii.* *THE NEED FOR DYNAMIC CAPACITY*

One of the challenges that PGE faces as a system operator is that we are required to match our system generation to our system load while that load is constantly changing. As PGE adds more variable generation, such as wind, to its portfolio of resources, that challenge becomes more demanding as both generation and load can change moment-to moment. Addressing the challenge of matching total generation with load in real time requires flexible generation that can change production levels over a significant range of operations, and do so in a short time frame. The challenge facing scheduling entities in the Pacific Northwest is that power, predominantly from trades, is currently scheduled for no less than one hour blocks[3]. In 2018, there may or may not be significant and reliable amounts of fast-acting demand response. Therefore, the majority of the responses to changes to load or variable generation must be managed with generators over which

[2] See PGE Phase 2 Wind Integration Report, pp. 13-15 for details of the forecasting methodology.
[3] While there has been some significant movement in the region towards regional imbalance or intra-hour market solutions, at the time of the study there was a large amount of uncertainty about the structure of the market and when/how access to that market might be available.

PGE has physical control and that have been scheduled to allow for intra-hour dynamic generation changes.[4]

As discussed in the Wind Integration Study Phase 2, the reserve requirements for which dynamic capacity must be set aside are as follows: Load Following, Regulation and Contingency Reserves (Spinning and Non-Spinning). Each of these reserves has an independent capacity requirement. Load following and regulation also have an energy requirement that must be assigned to the generator carrying the services.

Contingency Reserves have requirements for storage (for hydro plants) or fuel (for thermal plants). For hydro plants providing contingency reserves, the pond must have sufficient water to produce energy associated with having the spinning or non-spinning reserve called up during the hour. Thermal plants providing contingency reserves have similar fuel reservation requirements.

**Increasing and Decreasing Reserve Requirement Model Enhancement**

In Wind Integration Phase 2 Reserve calculations, an assumption was made, for simplicity, to make reserve requirements with associated energy (load following and regulation), and increasing and decreasing (INC/DEC) components symmetric. In other words, half of the range of system movement required to account for a particular reserve would be assumed to fulfill the increasing (INC) requirement and half would be assumed to fulfill the decreasing requirement. This symmetry between INC/DEC reserves created simple formulations of reserve requirements and also allowed for a simple accounting of energy and capacity in the constraints supplied to GAMS (two equations per reserve-providing plant). The INC and DEC range requirements are assumed to be the maximum movement above and below the average load net wind for the hour.

In operations, it is observed that the range requirements for load and wind INC and DEC reserves are not usually the same for a particular hour, and inputting independently formulated INC and DEC reserve requirements to the PGE model would better capture system needs for flexibility within an hour. Consider the following examples relating to load following reserve requirements below:

1. Example 1 is a simple example showing if there is just one load net wind movement that is basically equivalent to looking at 2 half hour load net wind blocks that are equally above and below the average load net wind for the hour.
2. Example 2 shows a situation where load net wind decreases steadily over the hour.

[4] For further description of the types of generators required to provide dynamic capacity and a preliminary discussion of reserve range and associated energy please refer to Wind Integration Study Phase 2 pp. 17-19

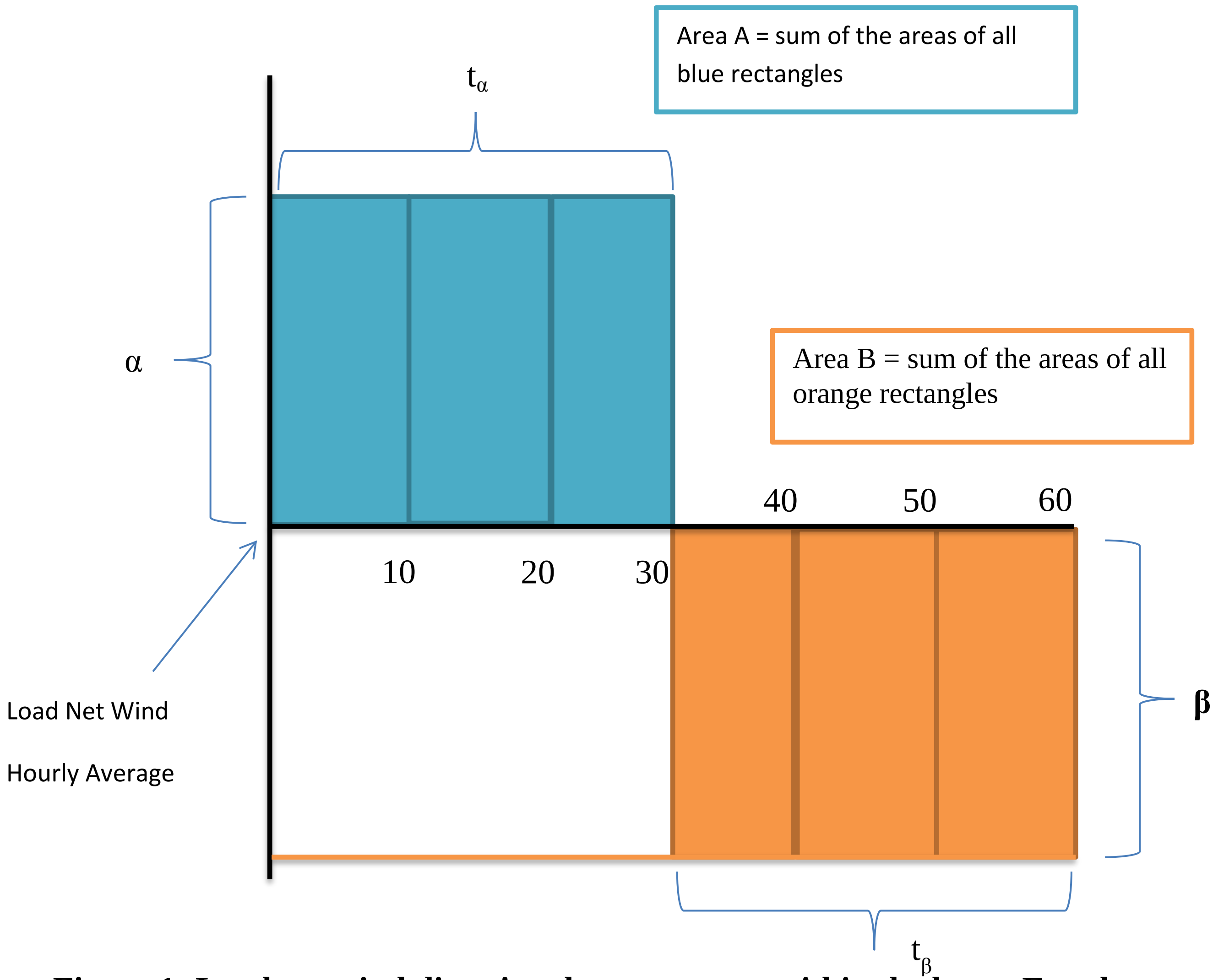



**Figure 1: Load net wind direction decreases once within the hour: Equal INC and DEC capacity requirements, $\alpha = \beta$ and $t_\alpha = t_\beta$**

The range and duration of required INC and DEC load following reserves are of equal and opposite sign (i.e. $\alpha = \beta$ and $t_\alpha = t_\beta$). In addition, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is also true that Area(A) = $\beta$*j - Area(B), where j is the number of time steps in the period, which implies that the energy produced by the reserve providing unit is equal for INC and DEC. This is a simple example of an assumed shape where the INC and DEC reserve requirement shape and the energy associated with providing both reserves are equal and opposite.

Now, consider another example where the intra-hour shape is more complex:

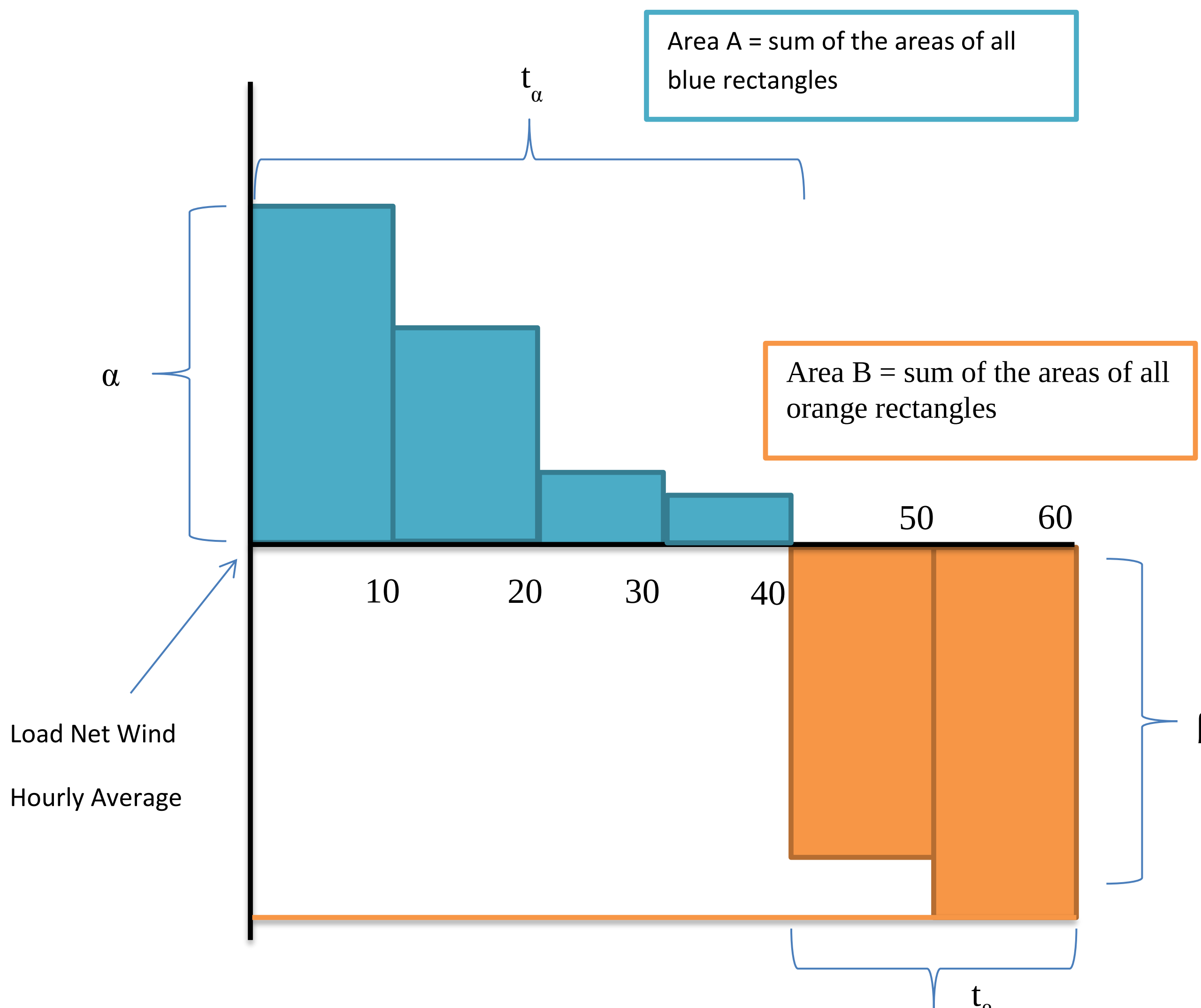



**Figure 2: Load net wind decreasing at a non-constant rate through the hour: Equal INC and DEC capacity requirements, $\alpha < \beta$ and $t_\alpha > t_\beta$**

The range and duration of required INC and DEC load following reserves are not of equal and opposite sign (in this case $\alpha < \beta$, but $t_\alpha > t_\beta$). However, again, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is NOT true that Area(A) = $\beta$*j - Area(B), where j is the number of time steps in the period. In the Phase 4 study, the reserve requirement ranges for load and wind in each hour are considered as above. Once the total reserve requirement ranges and associated energy to provide reserve over that range for Load Following INC, Load Following DEC, Regulation INC and Regulation DEC have been calculated, then the model chooses how to apportion those requirements throughout the portfolio by assigning a percentage to each available plant capable of providing such reserves.

The following is a derivation of the above percentage assignation of reserve requirement.

*Let* $\alpha_k$ *be the amount of inc reserve and let* $\beta_k$ *be the amount of DEC reserve provided by plant k. Then let* $\sum_k(\alpha_k) = \alpha$ *and* $\sum_k(\beta_k) = \beta$ *in a particular hour i. Let j be the number of data points over which Areas A and B are evaluated. In addition, let the following equations allow the energy accounting depend on the capacity reserved by a particular plant:*

$E_\alpha^k = (\alpha_k / \alpha)*(Area(A))/j$ *(energy created by holding out inc reserve on plant k)*

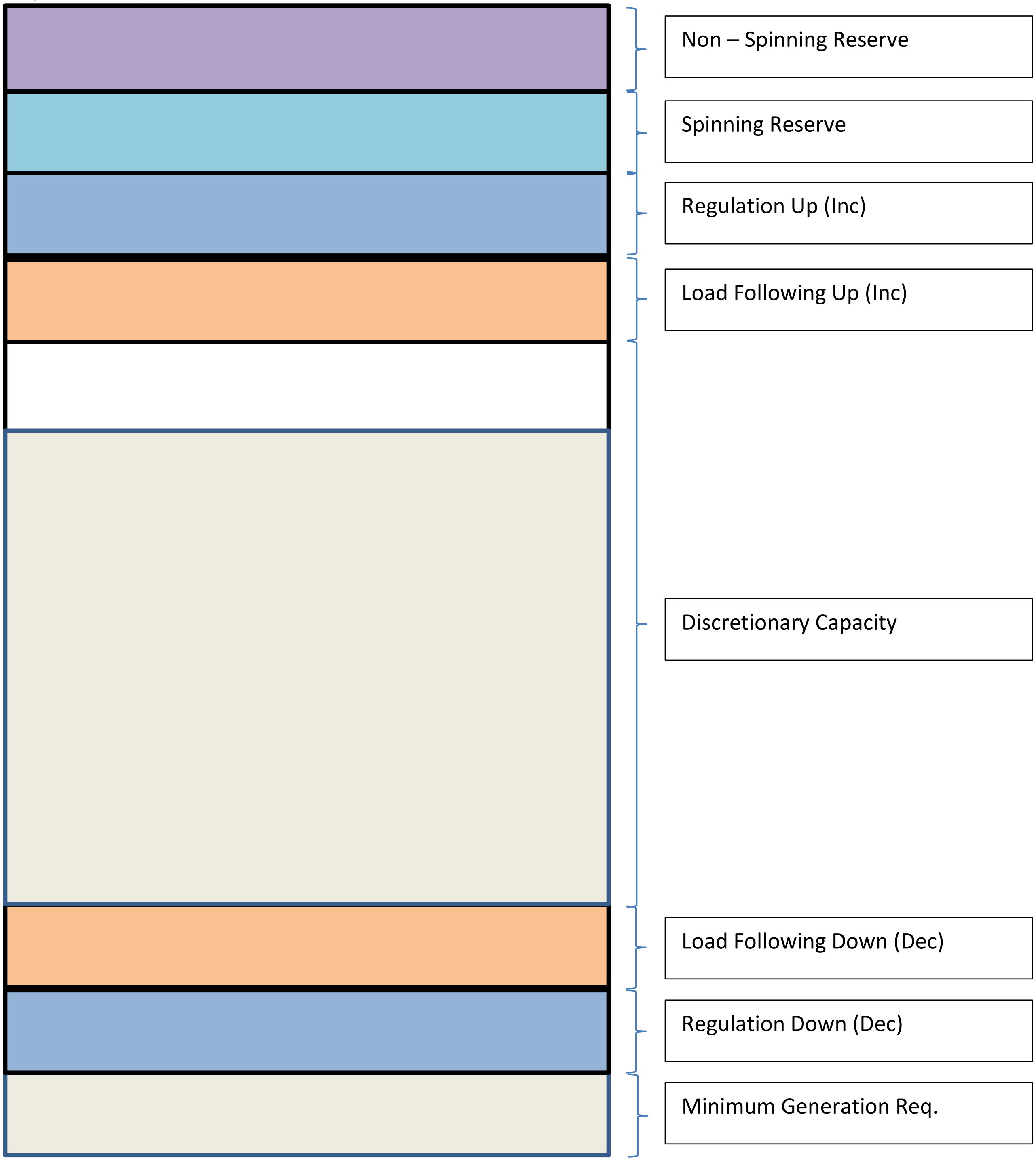
$E_\beta^k = (\beta_k / \beta)*(\beta*j - Area(B))/j$ *(energy created by holding out DEC reserve on plant k)*

*In this case,* $\alpha_k$ *and* $\beta_k$ *will be determined be the model, but Area(A), Area(B),* $\alpha$ *and* $\beta$ *will computed outboard and input into the model for each time increment (hourly, sub-hourly).*

When the model considers what percentage of the reserve requirements (regulation, load following, spinning, and non-spinning reserves) should be assigned to the plant also must consider other range limitations: minimum generation levels and discretionary energy dispatch. A plant's minimum generation is required to provide almost all reserves (non-spinning can be provided without minimum generation in some cases). The cost of this minimum generation is often the hurdle for a plant's provision of reserves.

In Figures 3 and 4 below, a plant's operating range is assigned all of the discussed reserve components, and minimum generation and discretionary energy. Note that the plant has some unused discretionary range because that is theoretically possible, however in practice, if the plant is generally dispatched for discretionary energy production it is usually because it is in the money and thus would use all of its discretionary range.

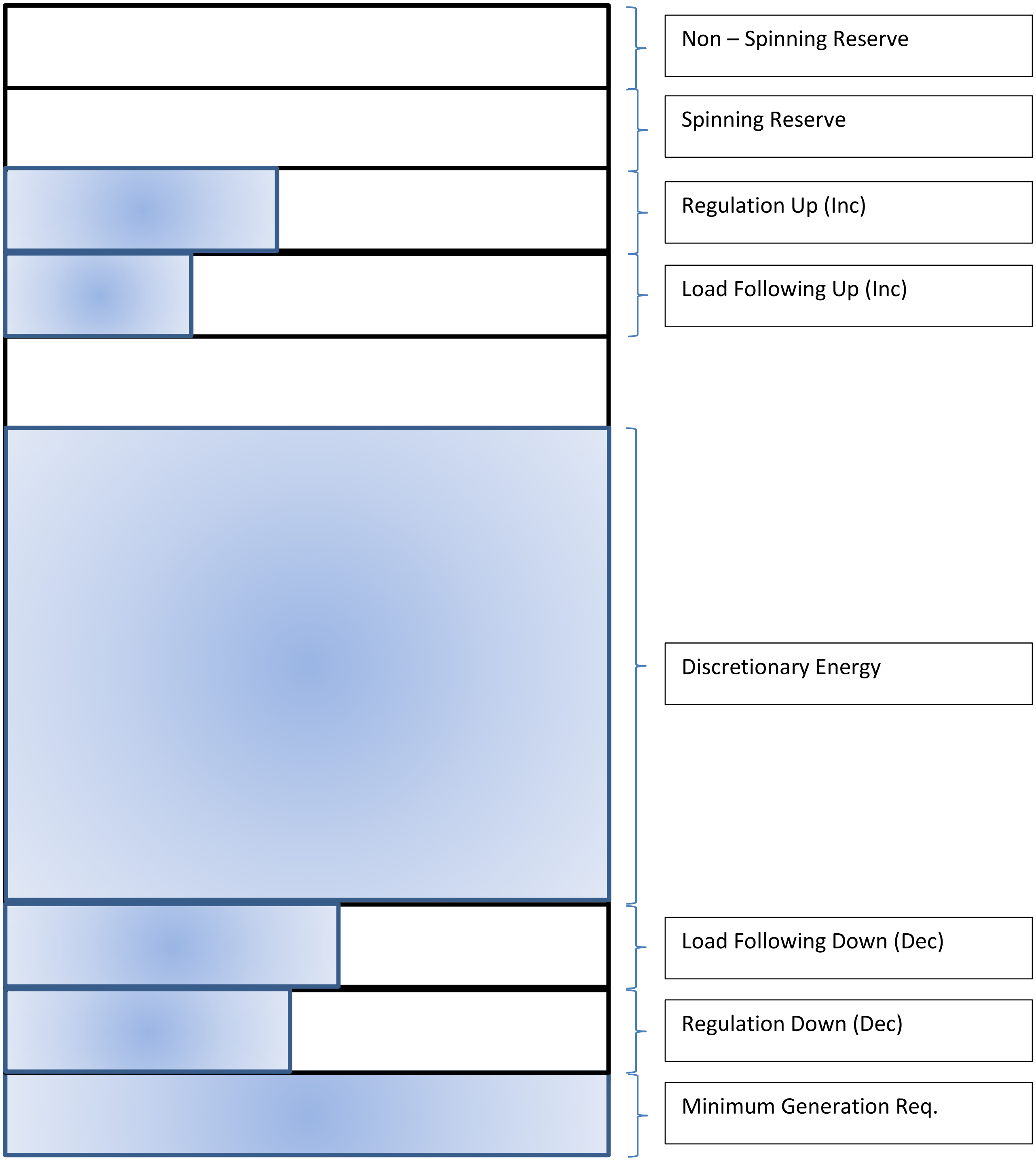
**Figure 3: Capacity Reservation on a Generator**[5]




[5] Note that this does not necessarily represent the energy produced by reserving a range of the generator for capacity purposes, for more detail on the associated energy see Figure 4 below.

**Figure 4: Example of Energy Produced by allocating capacities as in Figure 3**

- Add up the blue blocks to get the energy associated with the capacity ranges in Figure 3



Energy production is equal to the capacity provision of the discretionary range that is selected by economic dispatch and the minimum generation requirement[6]. In contrast, there is no energy production directly connected to the provision of contingency reserves (spinning and non-spinning)[7]. The load following capacity reservation[8] is required to cover the largest deviation by the ten-minute average data from the average energy produced over the appropriate dispatch time period. The regulation capacity reservation[9] is required to cover the largest deviation of the one-minute data from the ten-minute average data. By definition, the energy associated with providing those load following and regulation reserves (INC or DEC) must be less than the capacity reserved to meet that requirement. Another way of thinking about this is that for every bit of range of the plant that is reserved for contingency reserves, load following and/or regulation there is foregone opportunity for the plant to have used that range to produce baseload generation over the ENTIRE dispatch period.

### *iii. MODELING TOOLS*

*System Optimization*

PGE has developed an economic dispatch model to estimate operating costs for the PGE system. This is the principal model used in the Wind Integration Study. The model has a cost minimization objective function and a set of equations/inequalities which detail constraints on the operation of PGE's system. This model was constructed using three commercially available software products: GAMS, Gurobi, and Microsoft Excel. GAMS is used to program/compile the objective function and operating constraint equations. Gurobi is used to solve the resulting constrained optimization problem. Excel (and associated VBA code) is used for data input, reporting model results, and overall model control.

GAMS is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a set of integrated high-performance solvers. GAMS is tailored for complex, large-scale modeling applications, and facilitates the construction of large maintainable models that can be quickly adapted to new situations.

The Gurobi Optimizer is a state-of-the-art solver for linear programming (LP), quadratic programming (QP), and mixed-integer linear/quadratic programming (MILP and MIQP). It was designed to exploit modern multi-core processors. For MILP and MIQP models, the Gurobi Optimizer incorporates the latest methods including cutting planes and powerful solution heuristics. Models benefit from advanced presolve methods to simplify models and reduce solve times.

*Aurora Model*

[6] In other words, the entire capacity of the range reserved is dispatched over the entire dispatch period.
[7] In the model there is no energy produced even though a portion of the plant is reserved for contingency reserves. In real operation, these reserves will be dispatched only during regional contingencies, and once the contingency situation has been stabilized they need to be re-allocated and maintained without associated generation.
[8] The way load following is defined in the Wind Integration Model.
[9] The way regulation is defined in the Wind Integration Model.

PGE relies on the AURORAxmp Electric Market Model in its IRP for developing the long-term forecast of wholesale electricity prices and for portfolio analysis, as detailed in Chapter 9 of PGE's 2013 Integrated Resource Plan. AURORAxmp is a model that simulates electricity markets by NERC (North American Electric Reliability Corporation) area, detailing: 1) resources by geographical area, fuel, and technology; 2) load by area; and 3) transmission links between areas. As stated in the IRP, PGE uses it to conduct fundamental supply-demand analysis in the Western Electric Coordinating Council (WECC). AURORAxmp is also used to forecast 2018 hourly electricity prices for the Pacific Northwest. These hourly electric prices and the corresponding gas prices, were then input into the Wind Integration Model.

### *iv. Data Assumptions*

*Plants Available for Integration*

As noted in Section II.ii, above, PGE has a varied mix of generating resources but only a subset of these resources has the capability to provide the Dynamic Capacity required for wind integration. Specifically, we do not use the following thermal resources as part of our modeling:

Port Westward (excluding the duct burner) – plant technology was not designed to provide Dynamic Capacity.

Boardman – this baseload coal plant has a limited dynamic range. It is not allowed to provide dynamic capacity products until a Wear and Tear study better quantifies the risks of operating the plant more flexibly.

Colstrip – PGE does not directly control the operation of this baseload coal plant.

As described in Section V.ii above, for resources that are able to provide ancillary services, only the portion not used for discretionary energy production is available for Dynamic Capacity. A summary of PGE's resources and their specific ancillary services capabilities is provided in Table 1, below.

**Table 1: PGE's 2018 Portfolio (does not include Tucannon River or Biglow Canyon Wind Farms)**

| | Reserve Type | Mid-C | Round Butte | Pelton | Westside Hydro | Boardman | Colstrip | Port Westward | Port Westward Duct Burner | Coyote | Beaver – Simple Cycle | Beaver Combined Cycle | Carty | Carty Duct Burner | Port Westward 2 | Distributed Standby Generation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy | | X | X | X | X | X | X | X | X | X | X | X | X | X | X | |
| Capacity | Load Following | X | X | X | | | | | X | X | X | X | | X | X | |
| | Regulation | X | X | X | | | | | | | X | | | | X | |
| | Spinning Reserve | X | X | X | | | | | X | X | X | X | | X | X | |
| | Non-Spinning Reserve | X | X | X | | | | | X | X | X | X | | X | X | X |

*Fuel Prices*

PGE relies on independent third-party sources to project fuel prices. Specifically, to be consistent with our IRP methodology, Wood-Mckenzie provided reference, high and low case gas forecasts for 2018. Variable transportation costs are summed with gas commodity price to compute the delivered cost of the fuel, which, along with variable O&M, is used in the dispatch decision. PGE used the most recent available fuel forecast, which was May 2013.

*Regional Wholesale Electric Prices*

As in the Wind Integration Study Phase 2, PGE used AURORAxmp to generate the wholesale electricity prices used in the wind integration model for the dispatch of PGE generating resources. AURORAxmp simulates the fundamentals of supply and demand in the WECC and is the model used in PGE's 2013 IRP. Macroeconomic assumptions and modeling setup are those described in the

2013 IRP draft (as filed in November 2013) with minor changes not materially affecting electricity prices:

*Carbon regulation*

It was assumed that no specific carbon regulation is in place by 2018.

*Wind shapes*

Wind shapes for the WECC are those of the default 2012 AURORAxmp data base. EPIS (the developer of the Aurora market model) developed wind shapes for each area in the WECC using this NREL data. These were calculated by averaging the three years of NREL data (2004-2006), selecting sites/areas as typical of a region, computing a typical-week wind generation for every region and month with hourly detail (168 hours for each month), and reintroducing some of the variability in hourly generation lost in averaging .

For new plants in the Pacific Northwest, PGE computed a typical hourly shape (8760) representing the aggregate wind generation in the BPA balancing authority. We chose 2011 as the year that best fits the historical behavior of wind in the PNW and used the computed hourly shape from the BPA wind generation in 2011 to model any other generic wind plant in the PNW.

*Resulting electric prices*

The resulting average 2018 wholesale electricity price is $41.26 per MWh ($46.83 on-peak and $30.12 off-peak). In the Pacific Northwest, prices tend to peak in winter, when PNW load peaks, and in July-August, when California's load is peaking. Spring is typically a low price season, because of the abundance of hydro. Hydro is a major driver of prices in the Pacific Northwest. For modeling purposes we assume average hydro conditions.

*Loads and Load Forecast Error*

For Phase 4 of the Wind Integration Study, PGE projected its 2018 load data by employing a three-step process using 2005 actual load and 2005 Day-Ahead and Hour-Ahead load forecast data. The wind data is based on 10-minute intervals for the necessary Within-Hour granularity.

<u>Step 1. Realign Days of Week</u>

PGE developed the 2018 load data from 2005 load data by first aligning the 2005 actual load data days of the week with the 2018 days of the week. Because January 1, 2005 fell on a Saturday and January 1, 2015 falls on a Monday, we used the first Monday of January 2005 (January 3rd, 2005) for Monday, January 1st, 2018. Tuesday, January 4th, 2005 was then used for Tuesday, Jan. 2nd, 2018, and so on. This step is important because the load and wind data must correspond to the same days for consistency in deriving the "load net wind" concept.

<u>Step 2. Escalate 2005 to 2018</u>

The realigned 2005 data was then scaled up to 2018 levels by an escalation factor equal to the percentage increase from PGE's 2005 average annual actual load to PGE's 2018 average annual forecast load. The realigned and scaled data was then used to develop the projected 2018 real-time load data in the model.

Step 3. Develop Hour-Ahead and Day-Ahead Forecast Loads
PGE's 2018 Hour-Ahead and Day-Ahead forecast load data was derived by summing the 2018 forecasted-actual load data (derived in steps 1 and 2 above) with the corresponding 2018 Hour-Ahead or Day-Ahead load forecast error data. Specifically, the 2018 Hour-Ahead and Day-Ahead load forecast error data was created by: 1) taking the difference between the respective forecasted and actual 2005 loads, and then realigning to the matching day of the week, and 2) scaling the actual 2005 Hour-Ahead and Day-Ahead forecast errors in the same way the 2005 actual load data was escalated to 2018 forecast load data (described in step 2, above).

*Water Year*

PGE selected 2005 hydro flows for use in the wind integration model as a proxy for 2018 hydro flows. Of the three years (2004-2006) of NREL wind data used in the Western Wind and Solar Integration Study (from which EnerNex derived the wind energy data), 2005 was nearest to a normal hydro year for the Pacific Northwest. PGE did not use a 3-year hydro average of those years because the resulting hourly averages would mask the interactive effect of localized weather on hydro flows and wind speeds. The inputs of the wind integration model are temporally aligned to try to capture the effect of weather creating volatility in loads, wind, and hydro, and the resulting effect on the system trying to provide the Dynamic Capacity to meet the reserve needs of such volatility.

Specific hydro data used in the wind integration model includes:

- Mid-Columbia hydro energy – this is treated as one resource in the model, so historical (2005) flows from Chief Joseph were used.
- Deschutes hydro project inflows – USGS daily average inflows from 2005 were the assumed inflows for Round Butte.
- Hourly energy for PGE's run-of-river hydro – PGE historical PSAS (Power Scheduling and Accounting System) data from 2005 was used as proxy hourly energy data for Oak Grove, North Fork, Sullivan, Faraday, River Mill, and PGE's portion of Portland Hydro Project. (These hydro facilities do not provide ancillary services for wind integration.)

*Bid/Ask Pricing*

The wind integration model assumes virtually unlimited access to the energy market in the Day-Ahead and Hour-Ahead schedules. When the model chooses to purchase or sell energy in the Day-Ahead or Hour-Ahead stages to balance generation to load net of wind, there is an assumed bid/ask spread that affects the economics of using the market to meet load.

The Bid/Ask treatment is the same as in Phase 2 of the Wind Integration Study[10].

[10] See pp. 29-30 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

*General constraints for Hydro*

The hydro modeling methodology is the same as in Phase 2 of the Wind Integration Study[11], and all hydro data is consistent with the Phase 2 study, except PGE's contractual shares of the Mid-Columbia system are decreased in 2018 to reflect the expiration of the Wells contract.

*General Constraints for Thermal Plants Providing Ancillary Services*

In Phase 4 of the Wind Integration Study, Beaver and Port Westward Duct Burner are available to provide ancillary services as in Phase 2[12]. In addition, 50 MW per hour of intra-hour movement will be allowed on Coyote Springs (natural gas combined cycle cogeneration plant), per PGE's current understanding of the BPA's Dynamic Transfer Capability (DTC) business practice and best assumption of long term availability of DTC from Coyote. The 50 MW of range provided by the duct burner at PGE's future CCCT at Carty Reservoir is also available to provide some ancillary services. The 12 reciprocating engines at PGE's future Port Westward 2 plant are available to provide all ancillary services and are free to move between the min generation (8 MW, emissions constrained) and max generation (18 MW) although the number of engines available in any hour is determined by the designated scheduled outage rate.

<u>Constrained Gas Supply Enhancement</u>

In Phase 2, the wind integration model had no gas supply constraints limiting its nomination of gas to be burned in the day-ahead, hour-ahead and real-time economic dispatches. This modeling simplification over represented, in the Wind Integration Model, the flexibility the PGE system had to supply gas to Beaver, Port Westward and Coyote. Thus, to better represent the system operations, in Phase 4 of the Wind Integration Study, gas supply constraints have been applied to the operations governing Beaver (simple and combined cycle), Coyote, Port Westward (baseload and duct firing), Carty (baseload and duct firing), and Port Westward 2.

In actual operations, there are multiple ways that the gas desk can change the supply of gas after it has been nominated on a day-ahead basis. When there is a market, a portion of nominated gas can be sold at a couple different times after it is nominated. However, our model currently is not set up to capture the time windows in which renomination is available. Due to time constraints, renominating gas will have to be saved for a future enhancement to the model.

The other major way that gas is constrained, but has some flexibility is utilizing storage and/or drafting and packing the pipeline. This constraint is a daily accounting to ensure that a plant has not underused its nomination, and is thus storing unused gas in the pipeline (packing the gas, since it is a compressible fluid); or, overused its nomination, and is thus using more gas than allotted off the pressurized pipe (drafting the gas within appropriate pressure limits).

Beaver and Port Westward 2 can be fueled from a gas storage facility so are allowed a broader range of flexibility within the injection and withdrawal limits of the facility. This gas storage facility has

[11] See pp. 30-32 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[12] See pp. 32-33 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

an annual maintenance cycle; during this period, the change of gas supply for Beaver and Port Westward 2 dispatch changes after the day-ahead nomination is limited by the drafting/packing limits of the gas pipeline.

*Economic Feathering of Wind*

In Phase 2 of the Wind Integration Study, the wind output was a static input for each stage (Day-Ahead, Hour-Ahead and Real-Time), and the model had no choice on how the wind plant actually dispatched. This was a simplifying assumption for the Phase 2 study that would underrepresent system flexibility in certain rare situations, since when there is wind blowing, the generation (determined by rotation speed) from the plant can be reduced/stopped by pitching the blades of the wind plant (feathering). PGE's wind plants all have feathering capability (albeit different capabilities between the Vestas and Siemens units), so it makes sense to incorporate that aspect into the optimization.

One of the potential benefits of feathering wind is that it can reduce the additional reserve burden on the system due to wind. PGE does not currently have the methodology refinement required to adjust intra-scheduling period reserves (Load Following, Regulation) dynamically as the wind generation changes. However, the spinning and non-spinning reserve requirements can be dynamically reduced with any feathered generation in the model.

In Phase 4 of the Wind Integration Study, the model can make the decision to feather based on the cost of losing the wind generation. The production tax credit, renewable energy credit, and increased wear and tear cost to the plant caused by feathering wind are explicitly defined as inputs to the model. Replacement energy for the feathered wind generation is implicitly calculated in the model. These are all part of the variable cost calculation considered by the model when determining to feather wind.

### *v. Modeling Approach*

During Phase 2 of the Wind Integration Study, with the assistance of two external consultants, PGE developed a mixed integer programming model to assess the incremental operating (non-capital) costs of integrating wind resources into PGE's system. The model is a "constrained optimization model" with an objective function to minimize total system operating costs given a set of operational constraints. These operational constraints include plant dispatch requirements (minimum plant up-times, minimum plant generation requirements, etc.) and system requirements (Contingency Reserves [Spinning and Non-Spinning], Regulation INC/DEC, Load Following INC/DEC, etc.). The model allocates the total system requirements (e.g., total Spinning Reserve requirements) to the individual generators to minimize overall system costs. Currently, the model optimizes plant dispatch and system operation for a single year (2018). Given the heavy computational requirements, each of the 52 weeks is run separately on an hourly basis although functions for reserve requirements are developed from 10-minute data.

Phase 4 of the Wind Integration Study considers wind integration cost for three gas price sensitivities - reference, high, and low cases. In order to accurately represent system operation, the model is run in three stages corresponding to Day-Ahead, Hour-Ahead, and Within-Hour. At each stage, PGE's system is optimized subject to the operational constraints relevant at that stage. Commitments made in prior stages (e.g., purchase or sale commitments) are carried forward to the next stage as constraints. Total system operating costs at the third stage are used in assessing the costs of wind integration.

The model incorporates explicit reserves (reserved generation capacity) to address:

1) The Hour-Ahead uncertainty of wind INC/DEC;
2) Generation resource requirements for Within-Hour Load Following INC/DEC for wind; and
3) Generation resource requirements for Within-Hour Regulation INC/DEC for wind.

In addition, implicitly, spinning and non-spinning reserves are assigned economically within to generators per the level dictated by portfolio dispatch.

As in Phase 2, no reserves are specified in the model to address Day-Ahead wind uncertainty.

*Details of Modeling Approach and Results*

As discussed above, the costs of wind integration are identified by comparing total system operating costs, from a model run that incorporates the system requirements for wind integration, to total system operating costs, from a model run that excludes the system requirements for wind integration.

In Phase 4, to capture the system operation costs associated with integrating wind[13] for each of the three gas price sensitivities six model runs are required per Table 2 below. For example the system operation cost for wind integration in the reference gas case requires Run 1 (PGE integrates wind and load) and Run 1 (PGE integrates load only) described in Table 2. The difference between those runs is the systems operations cost associated with the self-integration of wind in the reference gas price case. Similarly, the differences between Runs 3 and 4, and Runs 5 and 6, are the increased system operation costs associated with self-integration of wind in the high and low gas cases respectively.

[13] As mentioned above, "PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources."

**Table 2: Descriptions of the Six Model Runs Required**

Note that PGE integrates load in all the runs, the delineation of "PGE integrates" refers specifically to wind.

| Identification | Description |
|---|---|
| **RUN 1** | **PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)** |
| **RUN 2** | **PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)** |
| **RUN 3** | **PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)** |
| **RUN 4** | **PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)** |
| **RUN 5** | **PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)** |
| **RUN 6** | **PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)** |

### *vi. Calculation for Reserves and Uncertainty*

The wind integration model accounts for three categories of reserves: Regulation, Load Following (including forecast error), and Contingency Reserves. The Contingency Reserve requirement is defined by the WECC (i.e., 5% for hydro and wind, and 7% for thermal resources) with requirements split equally between Spinning and Non-Spinning Contingency Reserves. The model simulates the different reserve requirements as hourly constraints for resource scheduling and dispatch across each of the three time horizons: Day-Ahead scheduling, Hour-Ahead scheduling and Real Time dispatch (Within-Hour). In Phase 2 of the Wind Integration Study, EnerNex provided PGE with a methodology for estimating regulation and load variability parameters for Day-Ahead, Hour-Ahead and Real Time (Within-Hour) scheduling, as well as the Hour-Ahead forecast error. However, PGE currently does not explicitly set aside reserves for Day-Ahead forecast error for either load or wind generation. Specific modeling for the reserves, by category and time frame, are described below.

*Reserve Requirement Calculation*

The reserve requirements for regulation, load following and forecast error for the Phase 4 study are calculated using the same methodology described in the Phase 2 study[14]. The only difference in reserve calculation is described in detail in Section V.ii: Increasing and Decreasing Reserve Requirement Model Enhancement above.

*Day-Ahead Scheduling*

In Day-Ahead scheduling, reserve predictions must be made for load variability and regulation for both load and wind generation. The Day-Ahead load forecast is input with a forecast error, but the model does not explicitly hold back reserves to cover the forecast error.

*Hour-Ahead Scheduling*

For Hour-Ahead scheduling, reserve predictions for the load variability and regulation from the Day-Ahead Scheduling step must be recalibrated to account for the Hour-Ahead load and wind generation forecast. Since PGE explicitly holds back reserves for forecast error in Hour-Ahead scheduling, additional reserves are calculated as follows:

- Reserves to cover the load forecast error are derived from historical PGE information (i.e., 2005 load data escalated to 2018 levels)
- Additional reserves held to cover the wind generation Hour-Ahead forecast error are determined by the EnerNex methodology described in the Phase 2 Study[15].

Plant dispatch is recalibrated from the Day-Ahead schedule to reflect the different reserve, wind generation, and load requirements.

*Real-Time Dispatch (Within-Hour)*

The forecast error reserve obligations that were established in the preceding Hour-Ahead scheduling step are released (when possible) in the Real Time (Within-Hour) dispatch step, and the reserve requirements for load variability and regulation are recalibrated. Plant dispatch is also recalibrated from the Hour-Ahead schedule to reflect different reserve, wind generation, and load requirements. Consequently, in each stage of the simulation, (i.e., Day-Ahead, Hour-Ahead and Within-Hour), the calculated reserve requirements for Regulation, Load Following, and Contingency Reserves are factored into the model's optimization of dispatching generation, capacity, and market resources.

[14] See pp. 40-42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[15] See p. 42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

# VI. Summary and Conclusions

## *i. Cost Summary*

PGE estimates the additional system operation costs incurred to self-integrate almost 717 MW of wind in 2018 would be $3.99 per MWh (in 2018$) at the reference gas price. PGE's estimate of the additional system operation costs to self-integrate the 717 MW in 2018 at the high gas price case is $4.24 per MWh, and at the low gas price case is $3.57 per MWh. It is again important to note that the aforementioned estimated self-integration cost estimates are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources. These results are summarized in Table 3 below.

**Table 3: System Operation Costs for PGE Self-Integrating Wind with Gas Price Sensitivities**

| **Identifier** | **Cost Saving For PGE** | **Run Delta Measures:** | **Cost ($/MWh)** |
|---|---|---|---|
| A | RUN 2 – RUN 1 | Cost saving for<br>Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation<br>(Cost of wind integration at **Reference Gas Price**) | $3.99 |
| B | RUN 4 – RUN 3 | Cost saving for<br>Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation<br>(Cost of wind integration at **High Gas Price**) | $4.24 |
| C | RUN 6 – RUN 5 | Cost saving for<br>Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation<br>(Cost of wind integration at **Low Gas Price**) | $3.57 |

## *ii. Conclusions*

PGE believes that Phase 4 of the Wind Integration Study accurately simulates the constraints associated with existing conditions and available resources to estimate the costs attributed to the self-integration of 717 MW of wind generation in 2018. The study has been subject to regular and rigorous reviews from the TRC and major participants in PGE's 2013 IRP, Docket No. LC 56. The TRC considers this study to be technically sound and have provided their unanimous endorsement. Regional stakeholders and PGE's Wind Integration Study Project Team have participated in three detailed public presentations regarding the intricacies of the study. Stakeholders have been provided the opportunity to examine, in detail, the methodology of the study and the results. They have also had the opportunity to comment on the methodology and make recommendations. In short, Phase 4 of the Wind Integration Study has been vetted in accordance with Commission Order No. 10-457.

As shown in the results in Table 4 below, the change in wind integration cost has a direct significant relationship to the price of gas. However, the larger overall effect is due to the net addition of balancing resources and wind diversity. There may be some threshold of gas prices where the effect on system operation cost due to wind integration is more drastic, but this study did not bear evidence to that threshold.

**Table 4: Comparison of Gas Plant Portfolio Changes, Gas Price Sensitivities, WI Phase costs[16]**

| Study Name | Study Year | Gas Plants Capable of Providing Reserves | Plants fueled by Sumas | Plants fueled by AECO | Annual Average Sumas Gas Price | Annual Average AECO Gas Price | Wind Integration Cost |
|---|---|---|---|---|---|---|---|
| Wind Integration Study Phase 2 | 2014 | Beaver, PW Duct Firing | Beaver, Port Westward | Coyote | $ 5.23 | $ 5.17 | **$ 11.04** |
| Wind Integration Study Phase 2 | 2014 | Beaver, PW Duct Firing, **Proxy Port Westward 2** | Beaver, Port Westward, **Proxy Port Westward 2** | Coyote | $ 5.23 | $ 5.17 | **$ 9.15** |
| Wind Integration Study Phase 4 (reference) | **2018** | Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing** | Beaver, Port Westward, **Port Westward 2** | Coyote, **Carty** | $ 5.28 | $ 4.89 | $ 3.99 |
| Wind Integration Study Phase 4 (high) | **2018** | Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing** | Beaver, Port Westward, **Port Westward 2** | Coyote, **Carty** | $ 6.05 | $ 5.62 | $ 4.24 |
| Wind Integration Study Phase 4 (low) | **2018** | Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing** | Beaver, Port Westward, **Port Westward 2** | Coyote, **Carty** | $ 4.24 | $ 3.89 | $ 3.57 |

All evidence points to wind regime diversity between Biglow and Tucannon River as the single most influential factor in the cost estimate decrease from Phase 2 to Phase 4. In the Phase 2 study, the most reasonable site for the next available tranche of wind had a much higher correlation with Biglow than the Tucannon River Wind Project acquired in the 2011 RFP. Thus, the regulation and load following reserve requirements fell slightly and the forecast error dropped considerably. This

[16] Note that the **bold** resources differentiate from the Wind Integration Phase 2 Base Case.

significant reduction in reserve requirements seems to be highly dependent on spatial and temporal diversity between wind sites.

The advent of more available gas balancing resources as was also seen in Phase 2 seems to have a significant mitigating effect on wind integration cost; however, these effects are highly portfolio dependent.  Other changes between Phase 2 and Phase 4 that appear to have significant effect on the cost are follows:

(1) Reduction in PGE's contractual share of the Mid-C likely raises system operating costs.
(2) Addition of gas fueling constraints likely raises system operating costs.
(3) Revised understanding of BPA's dynamic transfer constraint which allows some generation movement at Coyote and Carty Duct Firing likely decreases costs.
(4) The model's ability to feather wind when system constraints leave the portfolio flexibility short likely decreases costs.
(5) Ability for the model to assign INC and DEC reserve requirements to units individually allows PGE's portfolio to provide reserves more efficiently and likely decreases costs.

### *iii. Dynamic Dispatch Program*

For PGE to self-integrate wind, join a future energy imbalance market or adopt a hybrid system integration solution, investment is required in software automation tools, generation control systems, and communications/IT infrastructure. There is also the potential need for personnel additions to manage the self-integration of variable energy resources. In addition, to be prepared for a future where units will be used more flexibly, PGE has contracted an in-detail study on the wear and tear costs of increased cycling of PGE's units and the installation of automatic generation control (AGC) systems on the thermal units that will be sent within-hour balancing signals.  PGE has currently folded all these efforts into a Dynamic Dispatch Program that will be completed in phases over the next few years.

### *iv. Future Potential Remediation*

*Energy Imbalance Market*

Currently, PGE is participating in the region's Energy Imbalance Market (EIM) feasibility assessments.  An EIM is a hybrid of a bilaterally based market and a centrally cleared market model that seeks to redispatch in real-time, according to transmission availability, the flexible capacity made available to it by market participants. In an EIM, parties must enter the market with sufficient resources to stand-alone, in terms of energy and capacity to meet load and balancing requirements, as the market does not provide flexible reserve capacity to participants. EIM participants demonstrate their resource sufficiency through a combination of scheduled market purchases and identified resource plans for their owned assets. Whether for intentional, or market instructed deviations where a more economic regional redispatch is sought, market participants will either pay or be paid for the difference between their actuals and schedules (i.e., their energy imbalance, paid to or by the EIM) for each EIM flow period.

PGE is actively participating in the formative discussions of two main regional efforts: the Northwest Power Pool Members EIM and the California Independent System Operator EIM proposal with PacifiCorp. While outcomes of each effort are currently unknown, and noting that PGE has limited ability to influence the ultimate outcome of these processes, PGE expects that some form of an EIM has the potential to be made available to entities in the Pacific Northwest within the next few years.

PGE will consider modifying a future Wind Integration Study to calculate system costs should PGE have the opportunity to participate in an EIM. However, it should be noted that wind integration costs for an entity operating within an EIM would be highly dependent on market structures that have not yet been finalized for either of the two main efforts and that the current system operation model may need to be significantly enhanced to accurately represent these market structures.

*Additional Flexible Generation*

As stated earlier, the cost for wind integration is dependent on the characteristics of the system available to provide the moment-to-moment movement that is required to keep generation and system load in balance. If additional flexible resources are added to the PGE system, then the cost to provide wind integration will likely decrease.

### v. *Next Steps for PGE's Wind Integration Study*

Because variable generation resources place unique demands on system operation and reliability, PGE reiterates that understanding the physical needs and costs of wind integration is an ongoing effort. While PGE has not yet formulated a formal list of next steps, or tried to prioritize them, the following items are presented for further consideration. PGE's Wind Integration Study Project Team welcomes suggestions and feedback from stakeholders regarding prioritization or other study items may not be listed.

Phase 4 incorporated some the changes suggested in Phase 2 including the following:

- Evaluate impact of natural gas price variability
- Assess impact of transmission and gas supply constraints
- Evaluate impact of additional flexible gas generation resources
- Delineate between INC/DEC reserves
- Cost effects of feathering wind

Future Phases of PGE's Wind Integration Study may include:

- Evaluating the net impact of moving to sub-hourly scheduling;
- Evaluating the net impact of developing and operating a regional energy imbalance market;

- Estimating the value of adding additional flexible gas generation;
- Estimating how wind integration costs change with a higher or lower amount of variable resources to integrate;
- Better understanding the impact of a poor water year;
- Exploring the impact of changes to scheduled maintenance outages.

The PGE Wind Integration Study Project Team will continue to evaluate and improve its modeling tools and software, as needed, and will also continue to monitor the industry for Wind Integration Study best practices.

**Attachment 1**

The Technical Review Committee (TRC), operating under the principles established by the Utility Variable-Generation Integration Group (UVIG) and available at http://variablegen.org/wp-content/uploads/2009/05/TRCPrinciplesJune2012.pdf, wishes to congratulate you and the entire study team on completing the PGE Wind Integration Study Phase IV. The TRC endorses the study methodology, execution, and the final results presented to the TRC. The results naturally depend on the assumptions concerning balancing area and regional grid operating practices and scheduling opportunities which remain in a state of flux in the Pacific Northwest. We have enjoyed working together on this project and feel it has advanced the state of the art in wind integration studies.

Thanks Again

Brendan Kirby

Charlie Smith

Michael Goggin

Michael Milligan

Bob Zavadil

# *Appendix E*

## *PGE IRP Meeting Agendas*

# *Appendix E: IRP Meeting Agendas*

**Public Meetings**

**1st Public Meeting - April 3, 2013**

- IRP process overview
- Updates since 2009 IRP
- Current status of RFPs
- New topics and content for 2013 IRP
- Load forecast
- Resource need through 2020
- Customer Focus:  Resource Preferences / Demand-side Resources
    - Customer Attitudes & Preferences - Definitive Insights
    - Energy Efficiency Resource Assessment - Energy Trust of Oregon
    - An Assessment of PGE's Demand Response Potential - The Brattle Group
    - PGE Demand Response Strategy and Actions
    - Smart Electric Water Heater Program

**2nd Public Meeting - May 28, 2013**

- Introduction
- Follow-up from first IRP Public Meeting
- E3 – "PGE Low Carbon IRP Portfolios"
- Automated Demand Response RFP Update
- Flexible capacity: demand and supply
- Supply-side resources
- Gas: prices, price ranges, supply, and transport
- CO2 costs and PTC & ITC assumptions
- Wholesale electric market prices
- Proposed portfolio analytics

**3rd Public Meeting - August 29, 2013**

- Introduction
- Updated load-resource balance
- Portfolios and Futures

- Portfolio results
- Portfolio observations
- Risk and uncertainty
- Loss of load probability
- PGE Wind Integration Study: Phase 4
- Transmission project update
- Appendix: Capacity contribution of central station solar PV

**4th Public Meeting - October 7, 2013**

- Gas transport/storage -- acquisition strategy
- Automated Demand Response update
- Distributed solar preliminary technical potential
- Colstrip 3 & 4 update
- Load/Resource Balance update
- Potential study/research Action Plan items for next IRP
- Final IRP Portfolio results
- Loss of Load Probability results
- Parking lot items follow-up

**Technical Workshops**

**1st Technical Workshop - May 17, 2013**

- Demand for Flexible Capacity

**2nd Technical Workshop - June 25, 2013**

- Portfolios and Action Plan
- Wind Capacity Factor

**3rd Technical Workshop - August 8, 2013**

- Wind Integration Study

# *Appendix F*

## *PGE IRP Carbon Reduction Candidate Portfolios Scope of Work*

## *E3 Final Report - "PGE Low Carbon IRP Portfolios"*

## *Priority Recommendations - the Environmental Group*

# Scope of Work for Development of Candidate Carbon Reduction Resource Portfolios

# Portland General Electric Integrated Resource Plan – 2013

**Introduction**

Portland General Electric Company (PGE) and a group of stakeholders[1] ("the Group") are seeking consulting assistance in developing a limited number of carbon reduction resource portfolio options ("Carbon Portfolio Options") for evaluation in PGE's 2013 Integrated Resource Plan (IRP) process.

**Background**

In 2010, the Oregon Public Utility Commission (OPUC) acknowledged PGE's 2009 IRP action plan, in which PGE agreed to cease coal combustion operations at its Boardman Generation Facility in Boardman, Oregon by no later than the end of 2020. In exchange for the Group's support of PGE's Boardman proposal, PGE agreed, in its next IRP, to work with the Group to develop a limited number of Carbon Portfolio Options to meet its anticipated electric resource requirements, including the replacement of Boardman coal generation, while seeking to achieve the best combination of expected costs and associated risks for PGE and its customers and also reduce the carbon footprint of the company's resource portfolio over time. PGE also committed to allocate sufficient funding, not to exceed $50,000 without PGE's prior approval, to secure technical consulting services on a one-time basis to assist in developing and evaluating the Carbon Portfolio Options. One or more suppliers of these services may be selected.

This process represents a commitment by PGE to work with the Group and other IRP stakeholders to develop and evaluate carbon emission reduction candidate portfolios that support Oregon's efforts to reduce greenhouse gas emissions while operating within the OPUC's least-cost/least-risk paradigm. Under this paradigm, cost is defined as the expected Net Present Value Revenue Requirement of the total PGE resource portfolio and risk is defined as potential cost variability. Performance ranking and subsequent selection of a "preferred portfolio" and IRP Action Plan from the candidate portfolios (including the Carbon Portfolio Options) will be driven by the objective of achieving the best combination of total portfolio cost and risk for PGE and its customers.

PGE and the Group recognize that, consistent with the OPUC's IRP Guidelines, any proposal for the replacement of Boardman coal generation in 2020 will likely be beyond the actionable range of the 2013 IRP Action Plan. Nonetheless, PGE and

[1] Citizens' Utility Board, Northwest Energy Coalition, Oregon Environmental Council, Renewable Northwest Project, and Angus Duncan.

the Group agreed to proceed with the one-time consulting services as part of the 2013 IRP process.

**IRP Process**
Stakeholder involvement in PGE's development of the IRP consists of a series of workshops open to all interested parties, along with opportunities for written comment and input regarding the key components of the IRP. PGE will initiate a limited number of workshops to collaboratively develop the Carbon Portfolio Options. Such workshops are expected to begin Q3 2012.

**State of Oregon Greenhouse Gas Reduction Goals**
The Oregon Legislature, in 2009, adopted non-binding goals for reduction of greenhouse gas (GHG) emissions attributable to Oregonians. These goals are not sector-specific, so electric utilities (for example) may reduce their GHG emissions on a slower or faster pace. The overall State GHG goals may provide context for the Carbon Portfolio Options.

**Deliverables: Resource Portfolio Options/Scenarios**
Specific features of the Carbon Portfolio Options will be developed in consultations with the Group, PGE and other participants in the IRP process. The consultant will then be expected to assist with evaluation of the Carbon Portfolio Options analytical results for cost, risk, reliability and other IRP performance factors. Carbon Portfolios Options will be evaluated against other portfolios developed during the IRP process and in accordance with PGE's IRP methodologies and OPUC IRP principles and guidelines.

A limited number of Carbon Portfolio Options will be identified. Candidate portfolios will reflect the estimated annual $CO_2$ emissions of the portfolio resources based on the IRP planning horizon of 20 years, which for PGE's 2013 IRP will be 2034.

In addition to generating resource options, candidate Carbon Portfolio Options may consider commercially available storage technologies and transmission options, as well as increased levels of demand management, energy efficiency, and vehicle electrification beyond the base case assumptions.

**Consultant Qualifications**
The preferred consultant will be familiar with IRP processes and procedures, preferably as they are practiced in Oregon; and with modeling tools, and analytical methodologies that PGE plans to employ in the prospective IRP.

The preferred consultant will have knowledge of, or demonstrate access to, expertise concerning technically feasible and commercially available supply and demand-side resource options available during the IRP planning period, including prevailing and advanced generation, storage, and transmission technologies and operating practices.

The preferred consultant will have demonstrated, in other work products and within other proceedings, an understanding of the technologies and strategies that can potentially be assembled into a candidate carbon reduction portfolio that is also competitive on cost, risk, and reliability criteria.

The preferred consultant will have a working knowledge of PGE's resource base, load requirements and other operating circumstances, and of the Western Electricity Coordinating Council, the Bonneville Power Administration and the Pacific Northwest context within which PGE operates.

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# PGE Low Carbon IRP Portfolios

May 28, 2013

Arne Olson, Partner
Jim Williams, Chief Scientist
Amber Mahone, Senior Consultant
Nick Schlag, Consultant

Energy+Environmental Economics

# BACKGROUND

# Energy and Environmental Economics, Inc.

- E3 has operated at the nexus of energy, environment, and economics since it was founded in 1989
- E3 advises utilities, regulators, government agencies, power producers, energy technology companies, and investors on a wide range of critical issues in the electricity and natural gas industries
- Offices in San Francisco, CA and Vancouver, B.C.
- 30 professional staff in economics, engineering & policy

# Project Objectives

- **E3 was hired by Portland General Electric (PGE) to assist PGE and a group of stakeholders in the development of a low carbon resource portfolio for PGE's 2013 Integrated Resource Plan (IRP)**
- **E3's primary task was to develop, in consultation with the stakeholder group and PGE, one or more potential low carbon portfolios for PGE to evaluate using its IRP tools in 2013**
- **The stakeholder group included five parties:**
  - Bonneville Environmental Foundation
  - Citizens' Utility Board of Oregon
  - Northwest Energy Coalition
  - Oregon Environmental Council
  - Renewable Northwest Project

# Contents

1. **Context for a low carbon portfolio**
   - Policy
   - Backcasting & downscaling
2. **Analysis of low-carbon resource options**
   - Efficiency
   - Renewables
   - Potential displacement of PGE's 20% ownership in Colstrip units 3 & 4 late next decade
3. **Development of candidate portfolios**
4. **Specifying a low-carbon future**
5. **Identifying future research needs**

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# POLICY CONTEXT FOR A LOW CARBON PORTFOLIO

# What Might a Low Carbon Future Look Like?

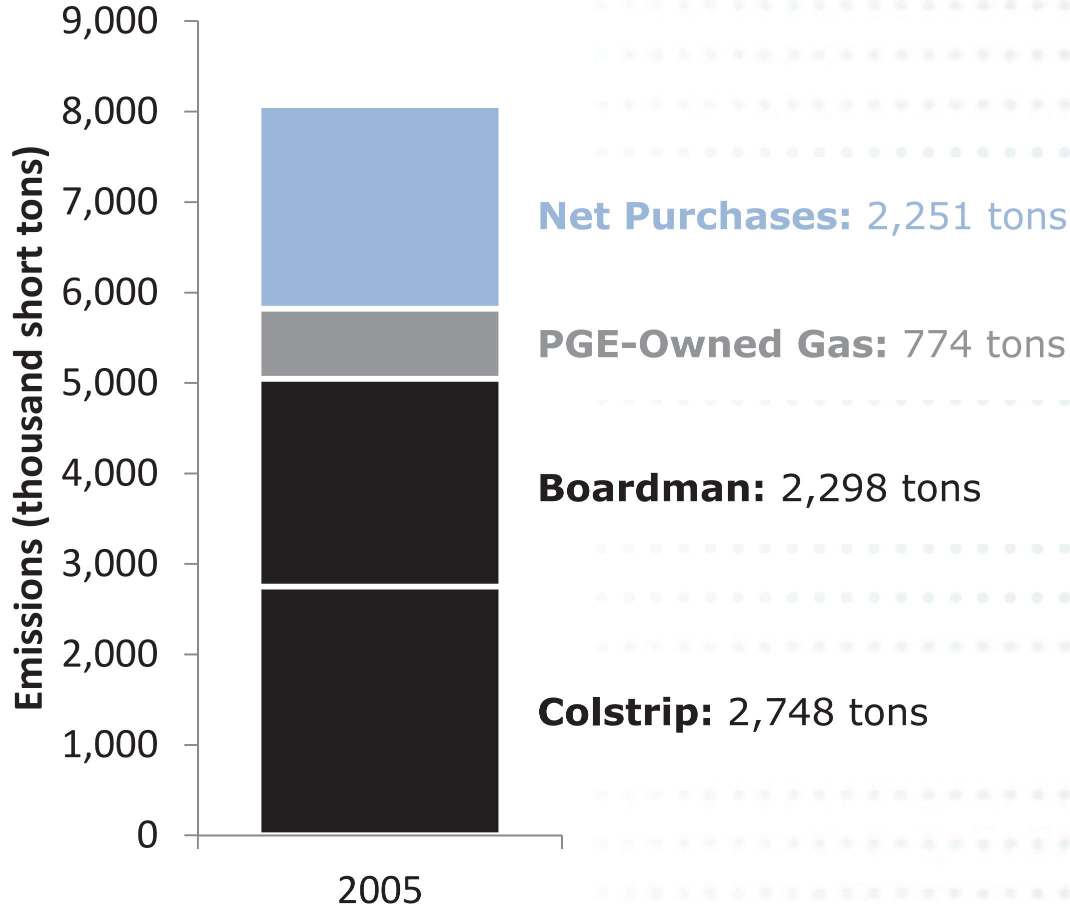
- **Oregon House Bill 3543 (2007)**
  - By 2010, arrest the growth of Oregon's greenhouse gas (GHG) emissions and begin to reduce GHG
  - By 2020, achieve GHG levels that are 10% below 1990 levels.
  - By 2050, achieve GHG gas levels that are at least 75% below 1990 levels
- **Senate Bill 101 (2009)**
  - Every even-numbered year, develop estimates to reach GHG goals by 2020 of 10% below 1990 (above) and 15% below 2005 levels
  - Because PGE's portfolio in 1990 was dominated by the Trojan nuclear plant and hydro, the stakeholder group agreed that a 2005 baseline would be appropriate for PGE's carbon targets
- **Possibility of an international, US, or WECC-wide carbon reduction policy**
  - IPCC goals
  - Waxman-Markey Bill: past legislation in U.S. House

# Framework for Portfolio Development

- **At the kickoff meeting, stakeholders agreed that applying the principles of backcasting and downscaling would provide a useful framework for developing portfolios**
  - **Backcasting:** working backwards from a long-term carbon reduction goal to determine necessary near-term actions and investments
  - **Downscaling:** zooming in from the state's long-term carbon goals to determine emissions targets specific to PGE
- **This process establishes a glide path for GHG emissions reduction for PGE**

# 2005 Portfolio Emissions

+ **In 2005, PGE actual generation and purchases created approximately 8 million tons of carbon dioxide emissions to meet retail load**
+ **Implied long term targets:**
  1. By 2020: **6.9 million tons** (15% below 2005 levels)
  2. By 2050: **1.6 million tons** (80% below 2005 levels)



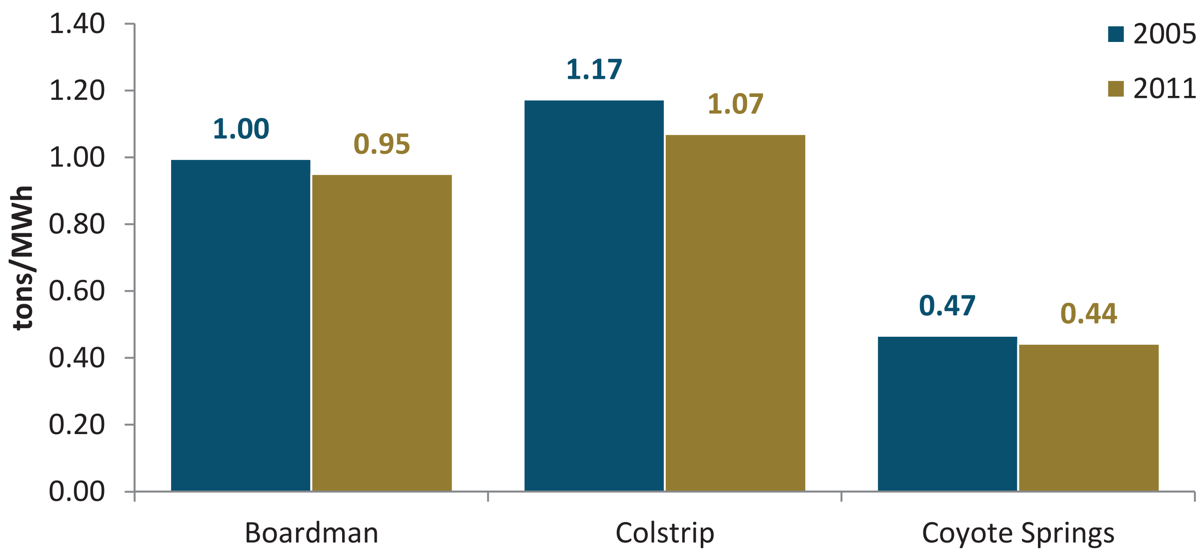
# Loss of Mid-C Hydro Contracts

- Unlike many utilities in the Northwest, PGE faces a unique challenge in the expiration of 146 aMW of hydro contracts over the next decade, compounding the challenge of decarbonization
- Not only will PGE have to meet growth and displace fossil generation with low-carbon power, but it must replace the load historically served by these non-emitting resources as well

| Contract | Annual Energy (aMW) | Contract Expiration Date |
|---|---|---|
| Hydro Contract A | 5 | 9/30/2015 |
| Hydro Contract B | 30 | 12/31/2015 |
| Hydro Contract C | 10 | 8/31/2017 |
| Hydro Contract D | 16 | 8/1/2018 |
| Hydro Contract E | 85 | 8/31/2018 |
| **Total** | **146** | |

# Improving Plant Efficiencies

+ **Since 2005, PGE has improved operational efficiency and reduced emissions rates at its coal plants and the Coyote Springs gas plant:**



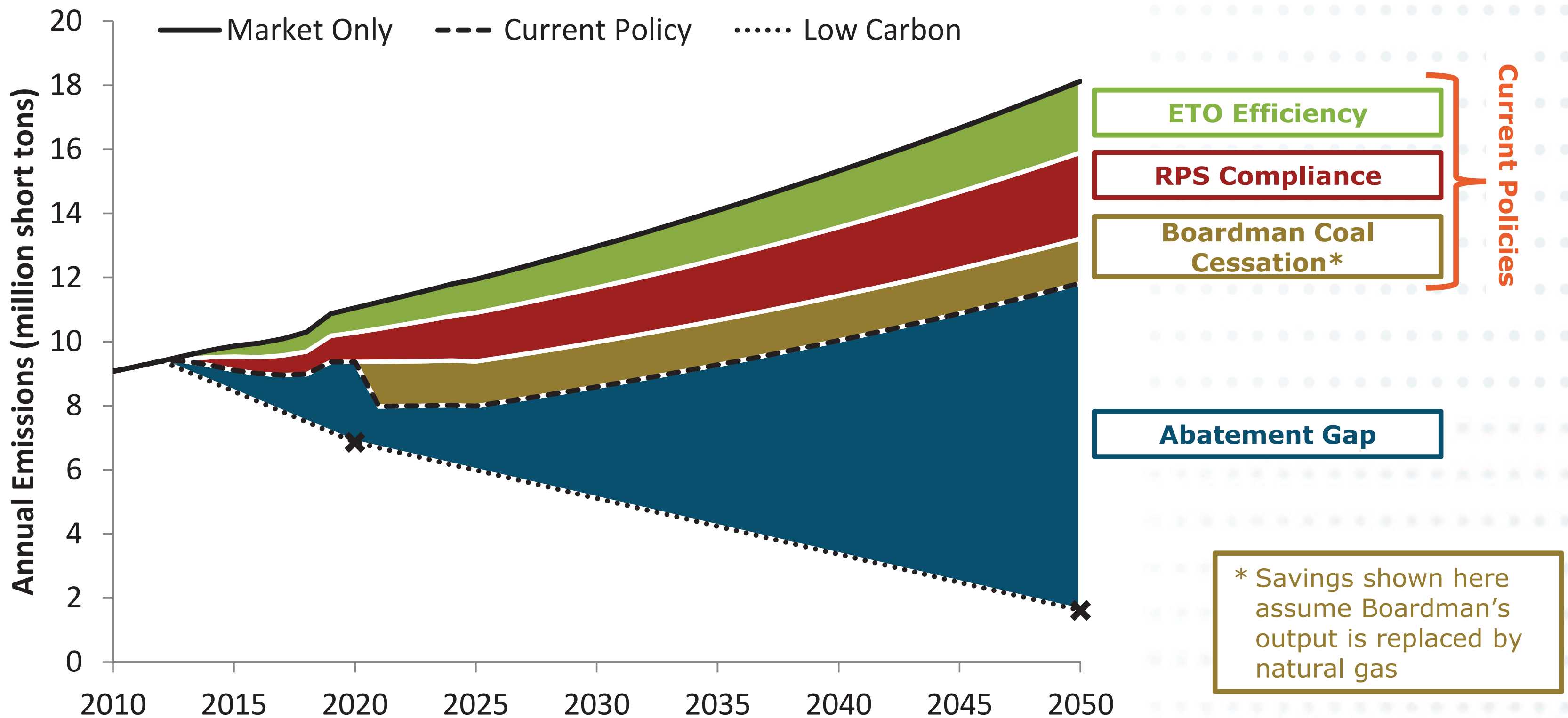
# Current Strategies

+ **Due to an Oregon RPS and action plans developed in past IRPs, PGE has committed to several emissions abatement strategies over the coming decade:**

1. **Customer energy efficiency:** PGE originated the initiative via SB 838 to expand funding from customers to acquire all achievable cost-effective energy efficiency identified by the Energy Trust of Oregon (ETO)
2. **Plant energy efficiency:** PGE has undertaken efficiency upgrades at its coal, gas, and hydro plants, resulting in more output without new emissions
3. **Renewable compliance:** PGE supported and helped design Oregon's RPS, which targets meeting 25% of PGE's retail sales with qualifying renewable generation by 2025; PGE is well ahead of the current 5% target and intends to remain in physical compliance with the 2015 15% target
4. **Boardman 2020 Plan:** as a result of analysis in its 2009 IRP, PGE committed to a cessation of coal-based operations at the plant by December 31, 2020
5. **Solar Standards:** while still small, PGE has implemented tariffs for net metering and feed-in tariffs to encourage customer solar PV
6. **"Buy-down" of gas heat rates:** PGE paid one-time fees to Oregon's Climate Trust to "buy down" the heat rates of Coyote & Port Westward; the Climate Trust purchases offsets on PGE's behalf

# Long-Term Emissions Trajectories

- By 2050, these PGE current strategies could be expected to save just over six million tons of GHG emissions per year
- Achieving long-term targets, however, will require PGE to intensify its emissions reductions strategies significantly



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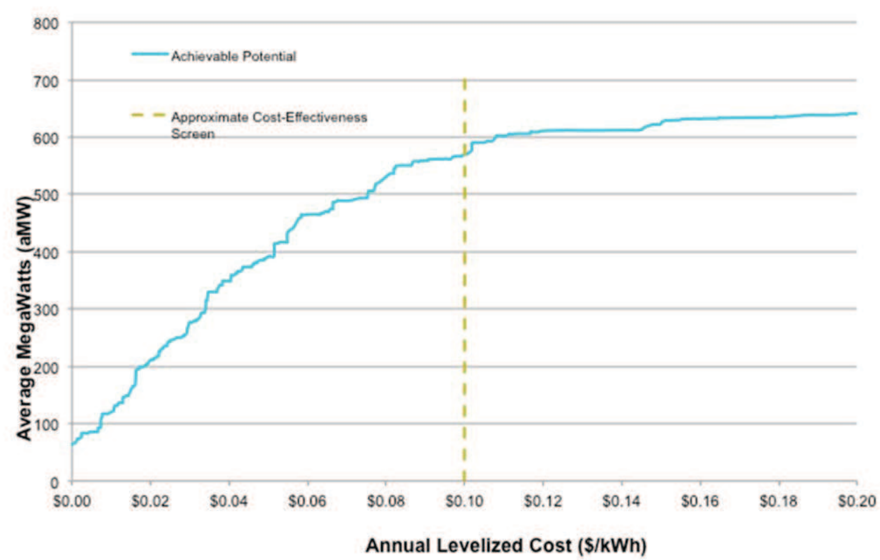
# RESOURCE OPTIONS FOR LOW CARBON PORTFOLIO

# Filling the Gap

+ **E3 has evaluated three primary options to fill this "abatement gap":**
  1. Increased energy efficiency
  2. Increased procurement of renewables
  3. Potential displacement of PGE's 20% ownership in Colstrip units 3 & 4 late next decade
+ **A combination of strategies will be needed to get on a pathway to long-term carbon reductions**
+ **This analysis uses a target of 80% emissions reduction relative to 2005 by 2050**
  - This is an economy-wide target that may not necessarily apply pro-rata to regions and/or utilities

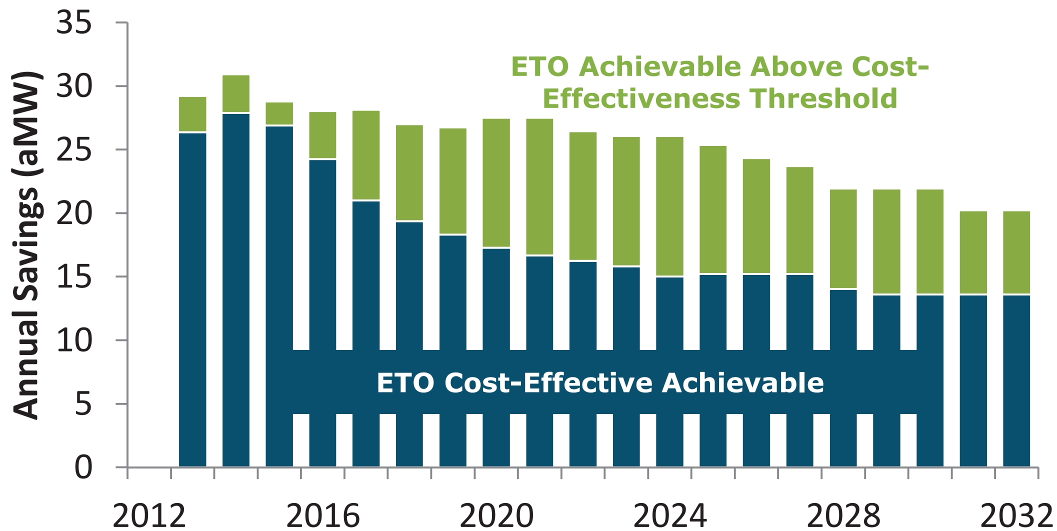
# Energy Efficiency

- **Under current practices, PGE's IRP portfolios assume the acquisition of all achievable cost-effective energy efficiency associated with commercially available technologies as forecast by the Energy Trust of Oregon (ETO)**
  - ETO EE potential also includes newly commercial technologies such as ductless heat pumps, water heater heat pumps, and LED lighting
- **In the context of a carbon-constrained world, it is useful to consider how the role of energy efficiency might be expanded in long-term planning exercises**
  - Commercialization of new technologies may expand the supply curve
  - Implicit valuation of carbon will shift the cost-effectiveness threshold
- **Accordingly, E3 has explored whether additional opportunities for efficiency should be considered in a low carbon portfolio**



# ETO Energy Efficiency

- In addition to quantifying achievable *cost-effective* energy efficiency, ETO also estimates the total achievable energy efficiency without economic constraints
- This quantity is a useful reference point in low-carbon resource planning because the cost-effectiveness screen used by ETO does not capture the implicit high value of carbon reductions in a low-carbon world



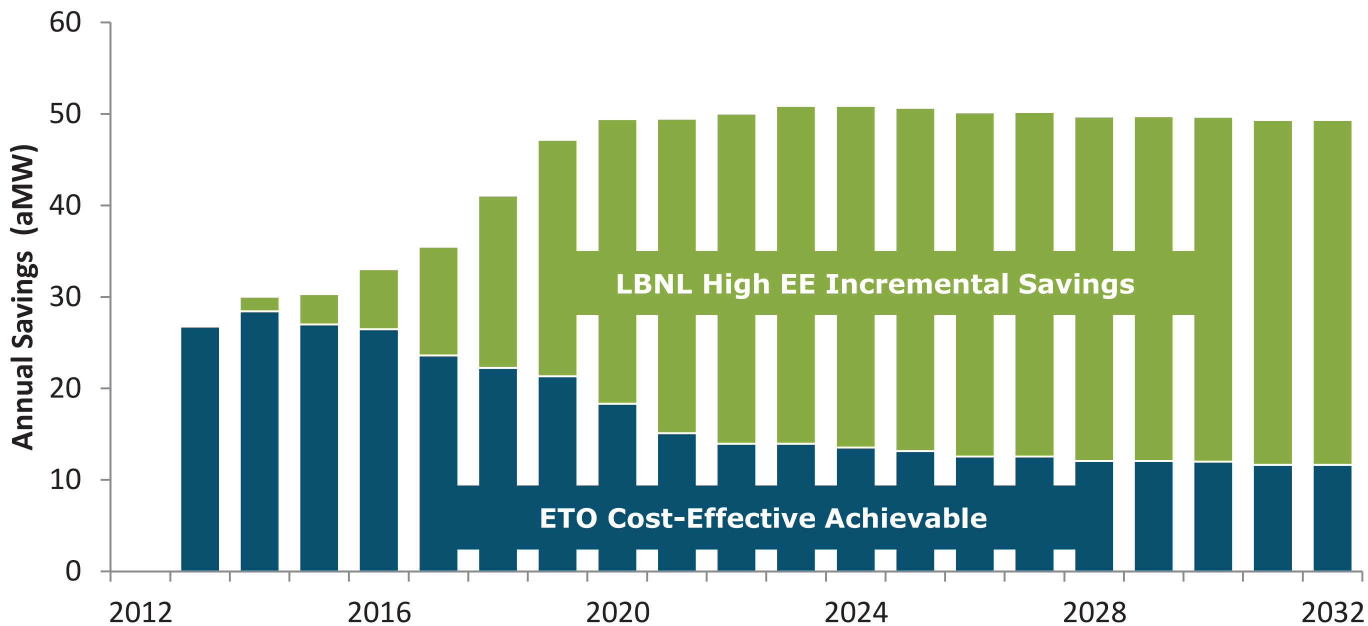
# ITRON/LBNL High EE Case

+ **As an input to WECC's 20-year transmission planning process, LBNL has worked with Itron to develop several load forecasts for each balancing authority in the WECC:**
  1. **Reference Case:** incorporates levels of efficiency consistent with utilities' IRPs (i.e. ETO assumptions for PGE)
  2. **High DSM Case:** assumes that by 2032, the *average* efficiency of each of 31 end uses has reached the level of today's best available technology (*no explicit screen for measure cost-effectiveness*)
+ **This forecast provides a second useful reference point that could be quickly adapted in a top-down manner to provide an efficiency input to this IRP:**

**Incremental efficiency** (2032) = **Reference Case Load** (2032) – **High DSM Case Load** (2032)

# Incremental Efficiency in High EE Case

- **The additional efficiency in the LBNL High DSM load forecast would represent a transformative expansion to ETO's traditional efficiency programs**
  - Nearly flattens load growth from today to 2032



# Review of High EE Savings Assumptions

+ **ETO has reviewed end-use assumptions for a number of substantial savings sources and concluded assumptions are reasonable and consistent with an emerging technology perspective on efficiency**

+ **ETO provided valuable end-use specific comments:**
  - **Commercial ventilation (18% of savings):** not an end-use where efficiency programs have traditionally focused, but there are opportunities to reduce consumption through separation of ventilation and space conditioning
  - **Commercial lighting (10%):** High EE assumptions may be conservative, as emerging LED applications will provide the opportunity for savings above any of today's commercial technologies
  - **Residential space heat (8%):** ductless mini-split heat pumps may be the mechanism to realize the hypothetical savings in this end use
  - **Residential DHW (0%):** potential savings are understated, as High EE case does not assume conversion to near-commercial heat pump water heaters

# Cost of Incremental Energy Efficiency

- LBNL recently released a report on projected EE program costs in the United States
- Findings indicate increasing marginal costs of achieving higher levels of efficiency; the generic cost curve below illustrates this effect but may not line up with PGE's expected EE costs

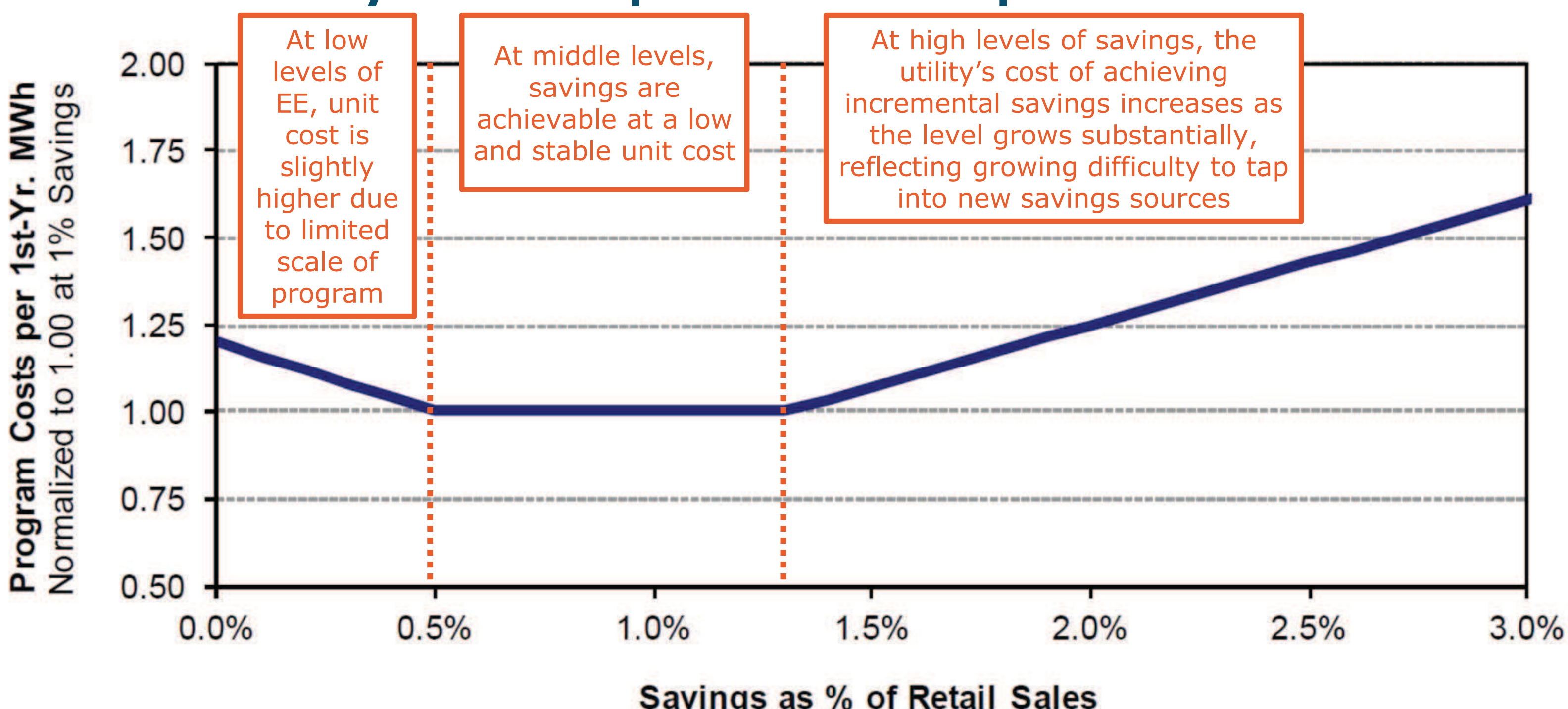



***Figure source:*** *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*

# Energy Efficiency – Next Steps

- Because of the uncertainty associated with the possible existence of additional energy efficiency beyond the amounts currently included in PGE's IRP portfolios, more work is needed to understand this resource
- The stakeholder group, the ETO, and PGE have discussed working together over the next 2 years to further examine the EE potential for the subsequent IRP

# Renewable Resources

+ **PGE's second major option for carbon emission reductions is further investment in renewable resources, which include:**
  - Local wind
    - Without new transmission (e.g. Gorge)
    - With new transmission (e.g. Steens Mountains)
  - Remote wind
    - Montana wind (in combination with Colstrip displacement)
    - Wyoming wind (with new interregional transmission line)
  - Solar photovoltaics
    - Distributed (e.g. rooftop)
    - Central station
  - Local biomass and geothermal

# Availability of Columbia Gorge Wind

- **While substantial development has occurred in the Columbia River Gorge, a large amount of potential remains**
  - WREZ study (2009) identifies over 5,500 MW of wind resource available for development in the Columbia River Gorge
  - NREL Western Wind data set suggests potential may be larger (10-15 GW)
  - Both data sets are dated and don't capture the fact that recent improvements in turbine technology have made more sites with low wind speed suitable for development
- **In a low carbon future, competition for wind in the Gorge may constrain PGE's ability to develop this resource in significant quantities**
  - PGE represents just under 15% of WA/OR total loads
  - PGE will compete with other WA/OR utilities—as well as California utilities—for resources in the Gorge
- **E3 has assumed that 2,000 MW of Gorge Wind would be available for PGE development**
  - Well-aligned with PGE's wind-heavy portfolios in the 2009 IRP
  - Represents a reasonable fraction of identified local potential
  - However, Gorge wind has little seasonal and diurnal diversity, presenting greater operational and cost challenges for integration and meeting peaking needs

# Assumed Availability of Other Wind Resources

- **To the extent that future IRPs conclude that it isn't least cost/least risk for PGE to fill its need with Gorge wind only, it will have to seek alternative resources**
- **E3 assumes that the quantity of other resources available to PGE is constrained by transmission:**
  - The amount of **Montana** wind that can be developed upon the displacement of Colstrip without new transmission needed is assumed to equal PGE's share of Colstrip (296 MW), equivalent to about 120 aMW at an assumed 40% capacity factor
  - Wind in the **Steens Mountain** region of Oregon can be accessed by building new transmission (likely 230 kV, which would provide 800 MW)
  - Wind in **Wyoming** can be delivered to Portland through the construction of a new 500 kV transmission line, which would allow for 1,500 MW of wind

# Limits on Biomass and Geothermal Availability

- **Biomass potential is limited by the availability of fuels**
  - NWPCC Sixth Power Plan identifies **203 MW** of biomass potential in Oregon due to supply constraints
  - 2009 IRP assumed **50 MW** of biomass would be available to PGE, an assumption that E3 has carried forward in this analysis.
- **Geothermal options are limited by the number of sites with sufficient thermal gradients for development**
  - 2009 IRP identified **380 MW** of in-state potential but included no more than **50 MW** in any single portfolio
  - NWPCC Sixth Power Plan relies on a 2008 USGS report, which identifies **595 MW** of resource in Oregon with 95% confidence
  - WREZ identifies **832 MW** of geothermal in areas near PGE's service territory
  - E3 has conservatively assumed that **120 MW** of the identified and undeveloped Oregon biomass and geothermal resources are available to PGE
- **For reference, PGE's recently concluded renewables RFP, yielded bids for about 65 MW each of biomass and geothermal**
  - None of the projects made it to the short list

# Solar PV Resource Options

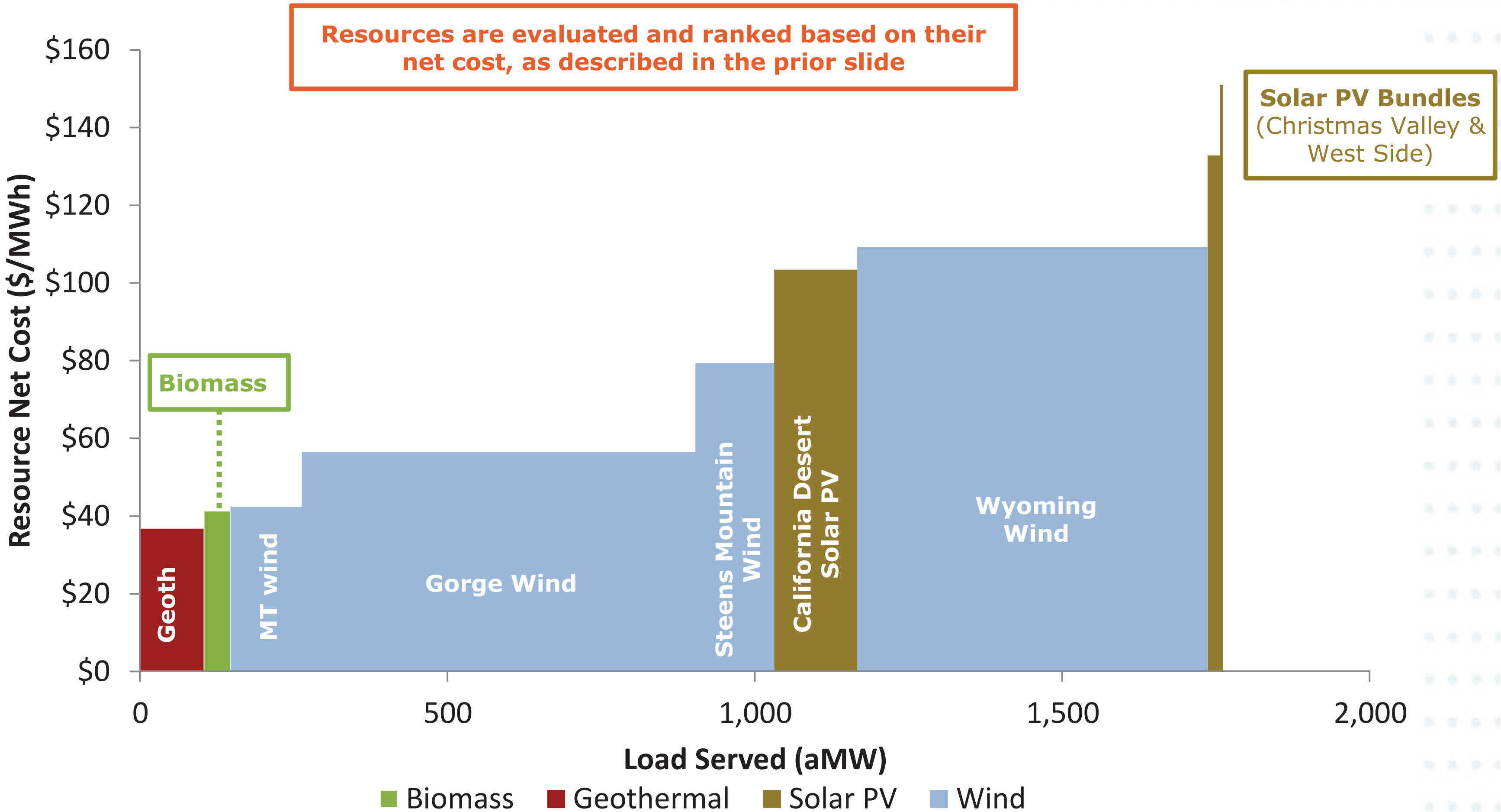
- **In the past few years, the costs of solar PV have declined substantially, presenting PGE with another possible resource alternative**
- **E3 has considered several solar PV options in its screening analysis of renewables:**
  - **Christmas Valley:** a reasonable quality solar resource that would not require substantial new transmission to serve PGE's loads. (PGE has recently entered into a PPA for the output from a 2.4 MW solar PV facility in that location.)
  - **Distributed:** local PV installed at or near loads in Portland, both ground-mounted and rooftop
  - **California Desert:** installed at a high quality resource site in California and wheeled to PGE loads through the CAISO

# Net Cost Approach to Portfolio Development

- In other portfolio design exercises, E3 has compared the "net costs" of new resources to generate a least-cost portfolio of resources
  - In addition to a resource's direct cost of generation, net cost considers the costs imposed by and benefits associated with a new resource on the system

| Formulation of Net Cost | |
|---|---|
| | Levelized cost of energy |
| + | Transmission cost |
| + | Integration (operating) cost |
| + | Fixed cost of integrating resources |
| - | Energy value |
| - | Capacity value |
| = | **Net cost** |

# Renewable Supply Curve




* Montana wind assumes availability of transmission line currently dedicated to Colstrip 3&4

# Displacing Colstrip

- **PGE is a minority owner in Colstrip units 3 & 4, which provide its customers with approximately 250 aMW of power each year**
- **PGE's share of Colstrip will become the single largest source of emissions in PGE's portfolio after 2020**
  - Accounted for approximately one third of the emissions attributed to PGE's 2005 resource portfolio
- **PGE has already committed to cessation of coal operations at Boardman by the end of 2020, but to achieve a 2030 emissions reduction target, displacing Colstrip by 2030 is necessary**

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# DEVELOPMENT OF CANDIDATE PORTFOLIOS

# Tradeoff Between Efficiency and RPS

- With the limited number of options available for carbon emissions reductions, there is an implicit tradeoff between efficiency and renewables in a carbon-constrained world

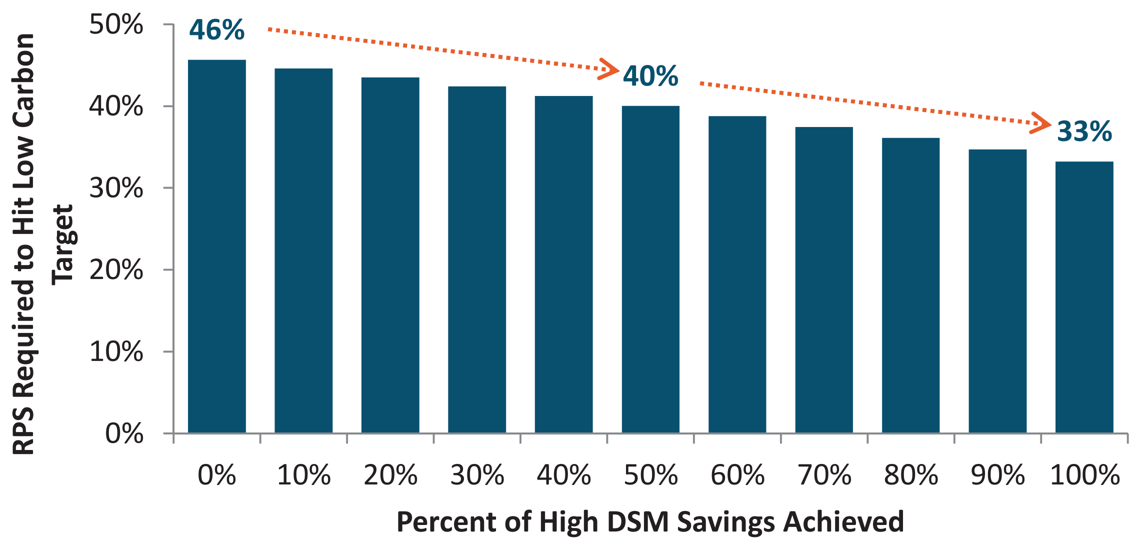
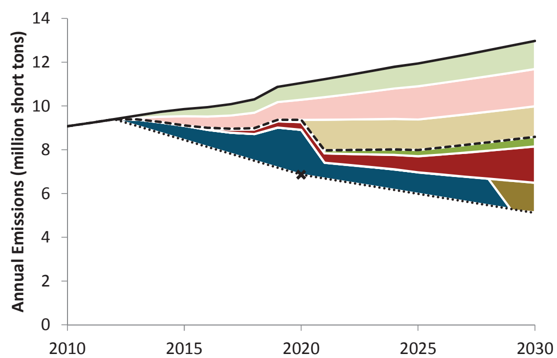
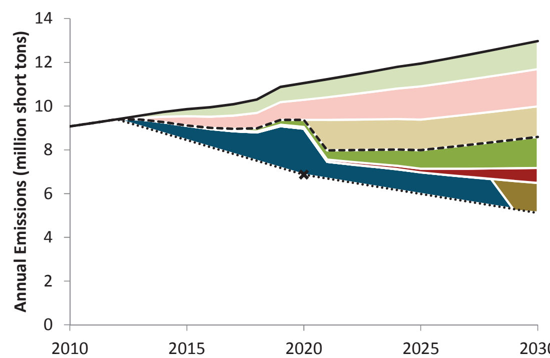



Figure based on load & resource mix in 2030; assumes Colstrip is fully displaced

- Due to uncertainties in the achievability of high levels of efficiency captured by LBNL's High DSM Case forecast, E3 has developed two low carbon portfolios as sensitivities on various carbon reduction strategies

# Two Low Carbon Portfolios

- **E3 recommends studying two Low Carbon Portfolios to highlight both the effects of decarbonizing with renewable investment and the possible impact of achieving transformative levels of efficiency**
- **Both portfolio meet the same carbon target for 2030, putting PGE on a glide path to longer term reduction goals by 2050**

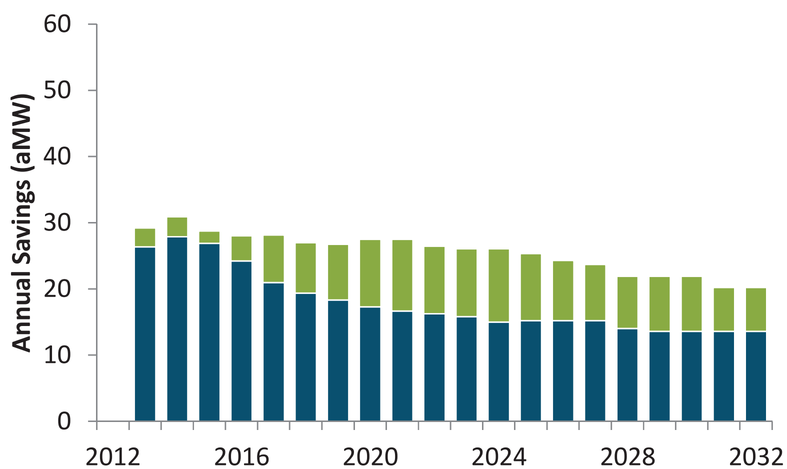
| Assumption | Portfolio #1 | Portfolio #2 |
|---|---|---|
| **Energy Efficiency** | ETO **Total Achievable** Potential | ETO Cost-Effective Achievable + **LBNL High DSM** savings |
| **Renewables** | **42%** RPS by 2030 (85% by 2050) | **33%** RPS by 2030 (75% by 2050) |
| **Colstrip** | Fully displaced by **2028** | Fully displaced by **2028** |
| **Resulting Carbon Abatement** |  |  |

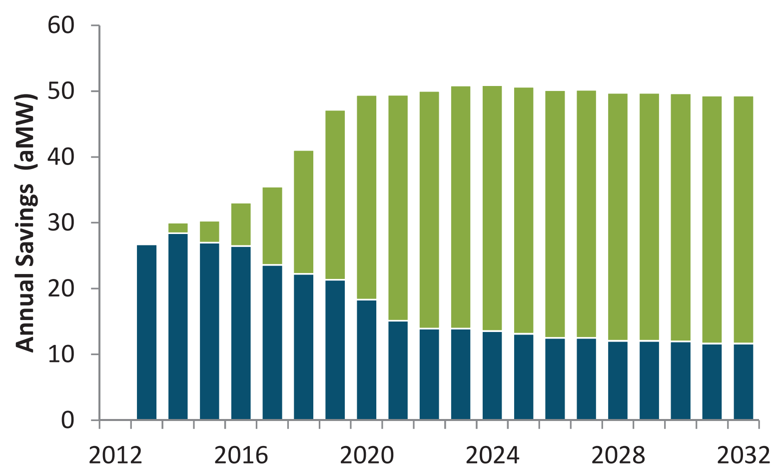
# Efficiency Deployment

+ **The low carbon portfolios assume that ETO's achievement of energy efficiency savings exceeds its current projections by a substantial margin**

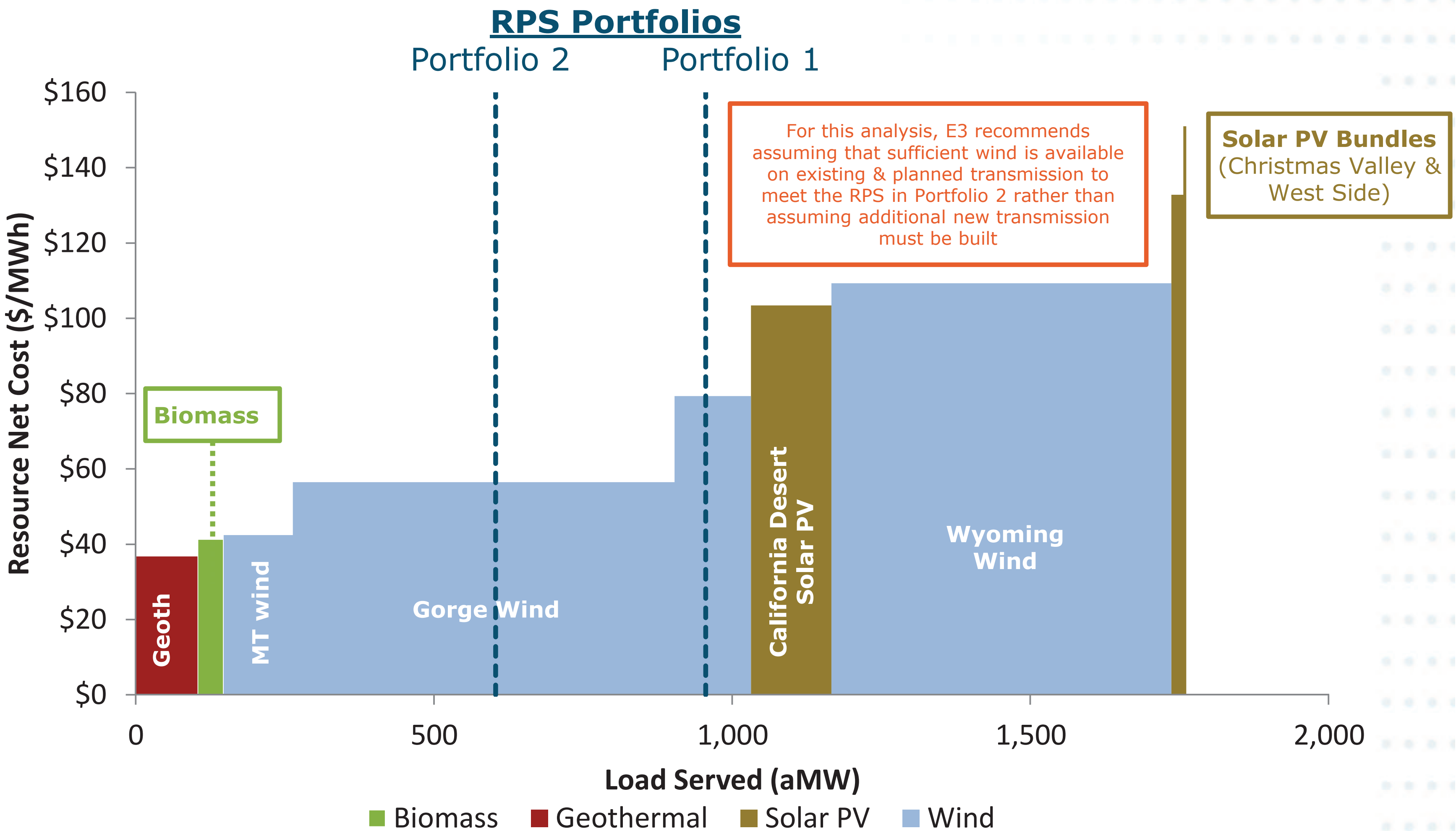
+ **In Portfolio 1 (ETO total achievable efficiency), incremental efficiency nearly offsets the decline in annual achievement in ETO's base case**

+ **In Portfolio 2 (ETO cost-effective achievable + full LBNL High EE savings), ETO achieves efficiency at a historically unprecedented level**



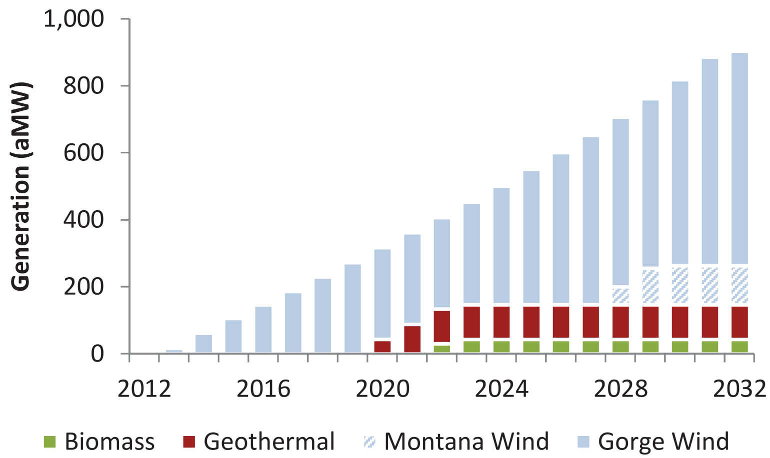



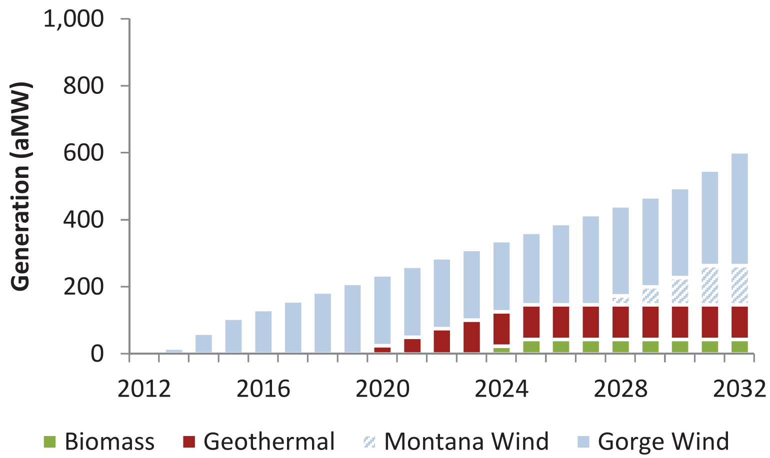
# Deriving RPS Portfolios from the Supply Curve



# Renewable Portfolio Investments

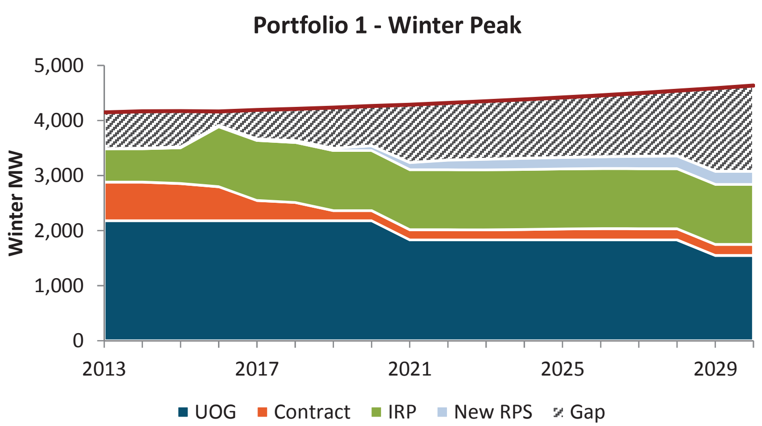
- The renewable resources included in each portfolio draw from the same pool—local biomass and geothermal, Gorge wind, and Montana wind—but differ in their magnitude of reliance on Gorge Wind
- Portfolio 1 assumes PGE will add about 2,000 MW of wind in the Columbia River Gorge by 2032
- Portfolio 2 contains a more balanced mix, with roughly half of 2032 additional renewables in the Gorge

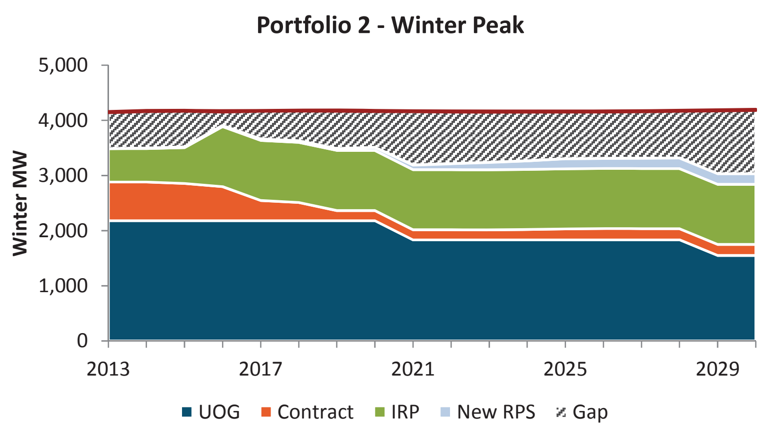


# Winter Capacity Balance

- Because wind power provides relatively little reliable capacity (~5% of nameplate), portfolios that rely heavily on wind power create large reliability-driven needs for new capacity
- This deficit is largest in Portfolio 1, in which PGE invests heavily in wind resources in the Gorge
- Portfolio 1 deficit: 1,550 MW by 2030
- Incremental efficiency in Portfolio 2 mitigates some of this deficit, as efficiency reduces peak demand
- Portfolio 2 deficit: 1,150 MW by 2030



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# SPECIFYING A LOW-CARBON FUTURE

# Distinction between Portfolios and Futures

- **To develop an action plan that is robust in the face of future uncertainty, PGE's IRP process examines the performance of each candidate "portfolio" against a range of potential "futures"**
  - **Portfolio:** a mix of resources which will meet PGE's future energy and capacity needs
  - **Future:** a set of input assumptions for the behavior of a set of variables (e.g. gas prices, carbon prices) over the planning horizon

Table 10A-3: Portfolios, Futures and Scenarios

| Future / Portfolio | 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 |

- **While E3's scope focused on developing assumptions for a portfolio, defining a low carbon future is important for that portfolio to have any coherence in the IRP process**

# Why Create a Low Carbon "Future"?

- **In the near term, most of PGE's renewable procurement will allow PGE to maintain physical compliance with Oregon's RPS policy**
- **In the long term, continued investment in renewables above current statutory requirements must be motivated by:**
  1. Legislative mandates for carbon abatement (e.g. mandatory GHG goals), or
  2. The presence of a clear economic benefit to PGE ratepayers to pursue a low carbon portfolio
- **Defining a future based on (1) does not fit well with Oregon's current IRP framework, as other portfolios could not be easily compared against the Low Carbon Portfolio because of their non-compliance with goals**
- **Therefore, E3 recommends comparing the Low Carbon Portfolio against others in the context of a future in which the value of achieving emissions reductions is high enough to justify investment in low carbon resources**

# Calculating an Implied Carbon Price

+ **How high will carbon prices have to be to prompt investment in renewables above statutory requirements in the long run?**

$$\text{Implied Carbon Value [\$/ton]} = \frac{\text{Net Renewable Cost [\$/MWh]}}{\text{Avoided Emissions [tons/MWh]}}$$

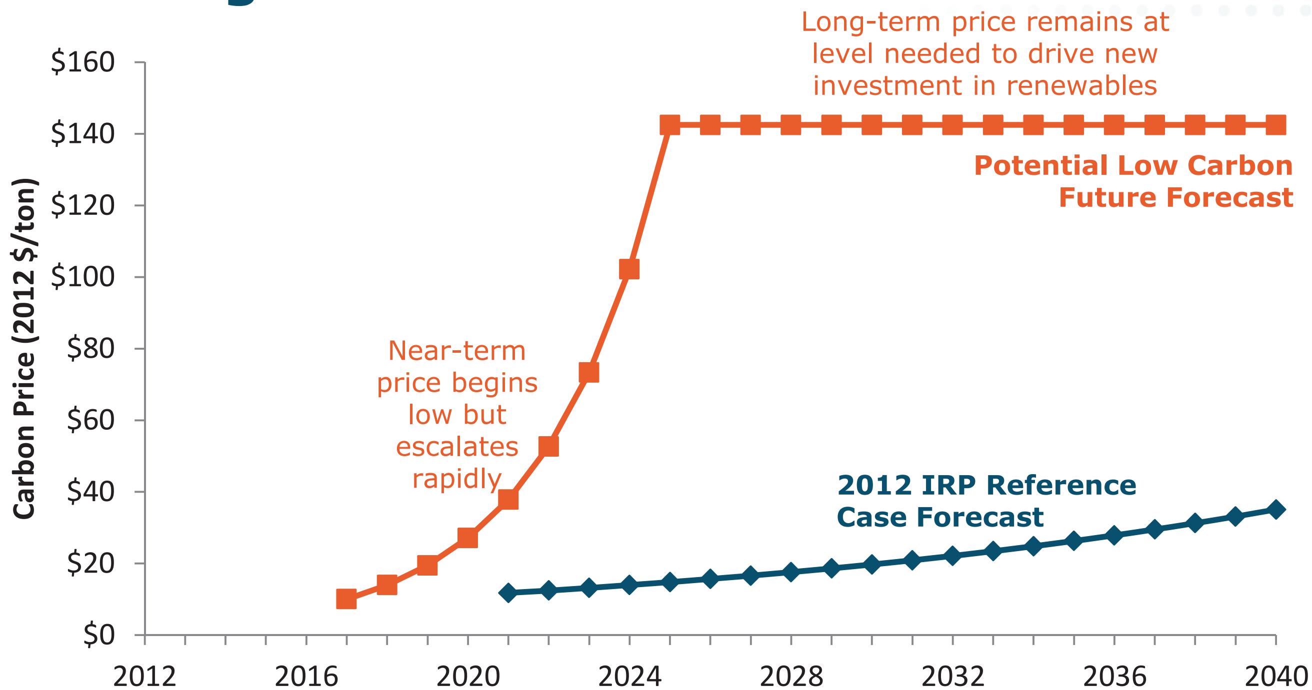
+ **PGE's marginal renewable investment cost implies a high cost of carbon**
  - When the PTC expires, the ***net cost*** of Gorge wind will rise to **$64/MWh**
  - Each MWh of renewable generation displaces approximately **0.45 short tons** of carbon emissions
  - The value of carbon implied by this investment is **$142/short ton**

| | Gorge Wind Net Cost in 2030 (2012 $/MWh) | |
|---|---|---|
| | Delivered LCOE | $91.75 |
| + | Transmission from BPA | $5.73 |
| + | Integration | $9.33 |
| - | Energy Value | -$38.74 |
| - | Capacity Value | -$3.96 |
| = | **Net Cost** | **$64.10** |

**Assumptions:**
- Energy & capacity values based on PGE avoided cost as filed in Schedule 201 (Qualifying Facility 10 MW or Less Avoided Cost Power Purchase Information)
- Capacity factor of 31% for marginal resource

# Carbon Price Trajectory

+ **Carbon price for a Low Carbon future would escalate from a low value in the near term to the level required to sustain investment in carbon-free technologies**



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# SUMMARY OF RESEARCH NEEDS

# Identifying Future Research Needs and Issues

- **In addition to providing technical assistance on low carbon portfolio development, E3 agreed to help identify issues and uncertainties that PGE should consider in its future evaluations of low carbon portfolios**
- **These outstanding questions, which could not be addressed in E3's scope, span a wide range of issues that PGE would have to address to realize a low carbon portfolio:**
  - Cross-sectoral implications of economy-wide low carbon targets
  - Technical and economic barriers to the development and acquisition of low carbon resources
  - Regulatory hurdles that may impede progress to carbon emissions reductions

# Summary of Future Research Needs

| Category | Key Questions |
|---|---|
| **Economy-Wide Targets** | 1. Will the electric sector be forced to bear a larger share of emissions reductions in an economy-wide strategy?<br>2. How will the burden of electric sector GHG emissions reductions be allocated among Oregon utilities?<br>3. How much electrification load could PGE expect to see under an economy-wide GHG reduction plan? |
| **Energy Efficiency** | 4. How much energy efficiency, beyond what is identified in ETO's supply curve, is or may become available to PGE over the IRP time horizon?<br>5. At what increased level of program funding can PGE expect to achieve these increased savings?<br>6. How can non-programmatic energy efficiency impacts be better captured in load forecasting?<br>7. How should ETO's cost-effectiveness screening for efficiency treat the probability of a carbon price under a low carbon future?<br>8. Is there an energy efficiency substitution effect that results in increased $CO_2$ emissions elsewhere in the economy? |
| **Renewables** | 9. How does integration cost change at different penetrations and with different amounts of intermittent resource diversity? |

# Summary of Future Research Needs (cont)

| Category | Key Questions |
| --- | --- |
| **Renewables (cont)** | 10. At what wind penetration would PGE need to build new flexible capacity to balance intra-hour variability of variable resources?<br>11. What would be the impact of an EIM or other regional initiatives on PGE's integration cost and flexibility needs?<br>12. How much wind in the Columbia River Gorge can PGE expect to be able to develop?<br>13. How will transmission affect PGE's ability to develop wind in the Columbia River Gorge?<br>14. What is the cost of transmission upgrades or RAS arming needed to achieve the full rating of the MT-NW path if Colstrip were to be displaced?<br>15. What is the cost of building new transmission to Steens Mountain or Wyoming?<br>16. Should PGE consider including solar PV generation located in a favorable location and wheeling the power to its system via CAISO? |
| **Conventional Resources** | 17. Would any of PGE's prospective resource investments be at risk of stranding in a Low Carbon future? |
| **Regulatory Issues** | 18. What near-term actions could be justified by the anticipation of much more stringent carbon regulations in the future? |

# Electricity's Role in an Economy-Wide Low Carbon World (1)

**1. How will the carbon reductions required of the electric sector compare to economy-wide targets?**

+ **Many studies that focus exclusively on the electric sector in a low carbon world assume that it will have to meet the same reduction goals as the economy as a whole**
  - i.e. if economy wide target is 80% below 2005 levels, assume electric sector reduces emission to 80% below 2005 levels
+ **In contrast, most economy-wide studies conclude that the electric sector will have to bear an outsize share of the emissions reductions, as opportunities in other sectors are limited**
  - Notwithstanding a major technological breakthrough, applications of biofuels are constrained by limits on supply
  - Future efforts to study the implications of low carbon portfolios should consider the implications of economy-wide targets on the reductions required of the electric sector

**Summary of Economy-Wide GHG Studies**
(% reduction relative to reference year by 2050)

| Study | Economy-Wide Target | Electric Sector Reductions |
|---|---|---|
| **Williams, et al.** | 80% | 86% |
| **SPSC Low Carbon** | 80% | 80% |
| **European Climate Foundation** | 79-82% | 93-99% |

**Studies Cited:**

Williams, J., et al. "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* (2012).

SPSC Low Carbon Case, WECC 20-Year Transmission Planning Process

European Climate Foundation, "Power Perspectives 2030: On the Road to a Decarbonised Power Sector," 2012.

# Electricity's Role in an Economy-Wide Low Carbon World (2)

**2. How will the burden of electric sector GHG emissions reductions be allocated among Oregon utilities?**

- **In addition to determining the appropriate share of GHG emissions reductions to require of the electric sector, policymakers will also have to choose how to allocate that responsibility within the electric sector**
- **Because utilities have different fuel mixes as starting points, they have different opportunities to reduce emissions relative to their baseline portfolios**
- **This analysis has assumed that PGE must meet the same reduction as the economy-wide target, but there are other ways that responsibility might be allocated**
  - e.g. uniform emissions intensity targets (tons/MWh) across utilities

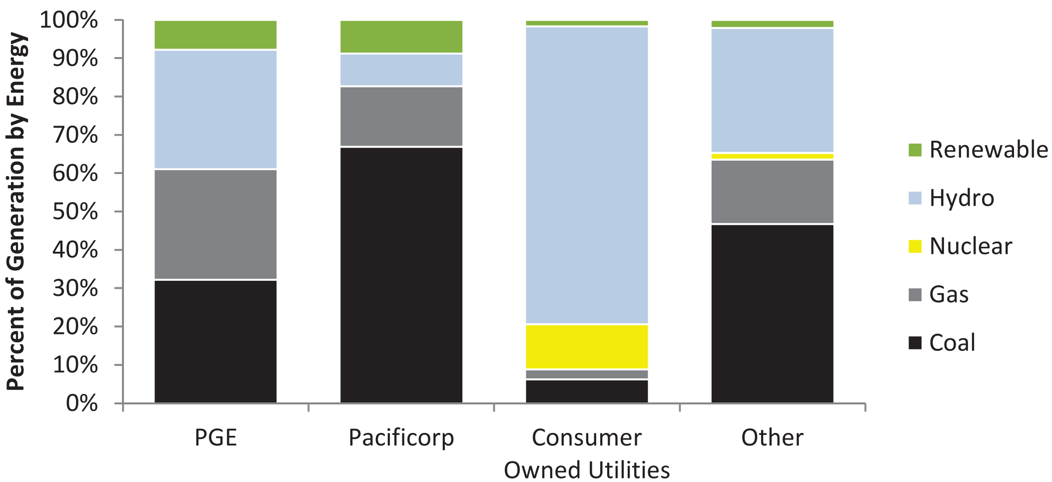
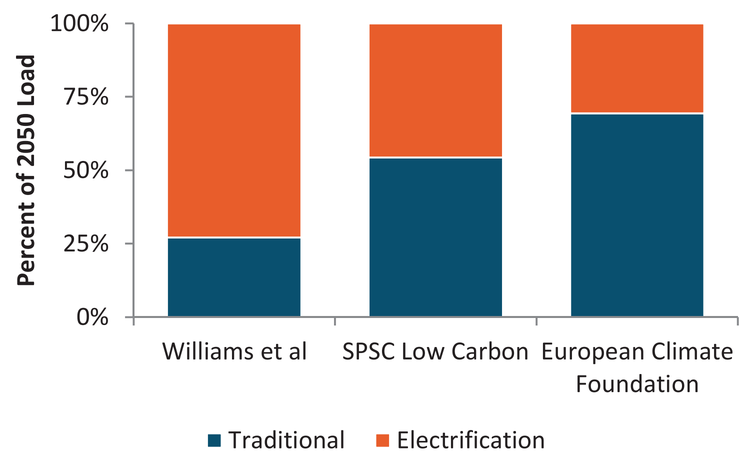



***Figure Source:*** *data from Oregon Department of Energy; based on fuel mix disclosure reports for 2010*

# Electrification in an Economy-Wide Decarbonization Effort (3)

**3. How much electrification load could PGE expect to see under an economy-wide GHG reduction plan?**

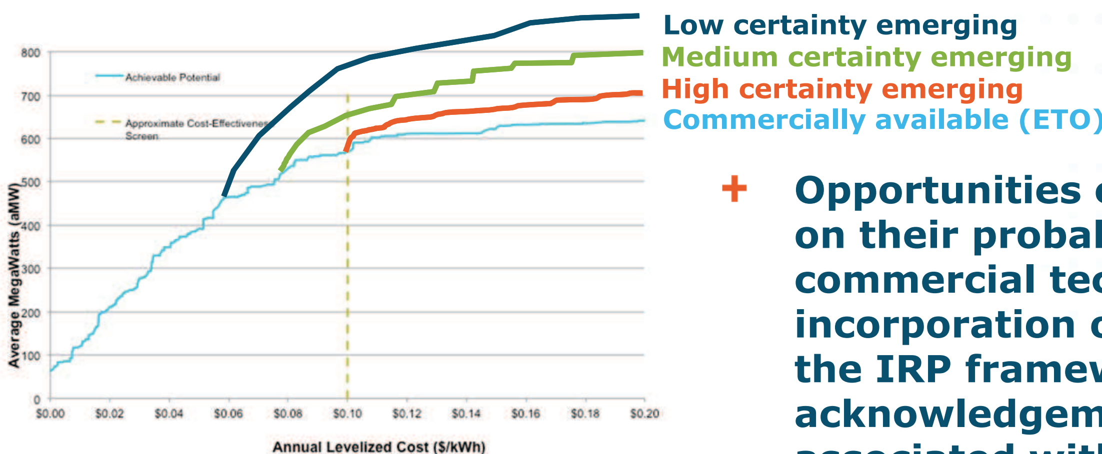
+ **While E3's current analysis assumed no cross-sectoral mitigation strategies, many studies agree that electrification will be key to achieving deep long-term GHG reductions**
    - This is another consequence of the limited opportunities for abatement outside of the electric sector
    - Transitioning end uses traditionally served by fossil-fuel combustion to low-carbon electricity presents a large opportunity for abatement but will intensify the challenge faced by the electric sector, which will have to decarbonize **while serving additional loads not traditionally planned for**
+ **Addressing this question requires understanding:**
    - The potential growth of the market for electric vehicles
    - Possibilities for fuel switching among residential and commercial end-uses
+ **For such a measure to be viable, utilities would have to receive credit/allowances for the emissions reductions**



# Quantifying Incremental Efficiency Potential (4)

**4. How much energy efficiency, beyond what is identified in ETO's supply curve, is or may become available to PGE over the IRP time horizon?**

- **Assumptions based on the High EE case provide an interesting scenario from an academic perspective but would need support from more concrete feasibility assessments to allow PGE to act upon them**
- **E3 has presented a framework under which emerging technology opportunities could be incorporated into ETO's traditional supply curve approach to efficiency**
  - As with commercially available technologies currently included in the supply curve, this approach would involve identifying and characterizing emerging efficiency opportunities




- **Opportunities could be classified based on their probability of realization as a commercial technology, allowing for incorporation of such technologies into the IRP framework with an acknowledgement of the risk associated with them**

# Costs of Aggressive Efficiency Programs (5)

**5. At what increased level of program funding can PGE expect to achieve these increased savings?**

+ **Determining the cost of funding an efficiency program that would achieve the same level of savings as the High EE case is a challenging exercise since the case is not built on the same measure-level data that ETO uses**
+ **E3 has used a generic relationship between program costs and savings levels established in a recent LBNL study that shows increasing marginal costs at higher savings levels, which is not ideal:**
  - PGE has historically invested in efficiency at a much higher level than other utilities in the United States and has achieved a large share of the "low hanging fruit" savings that are available to others
  - As a result, the cost function—based on data from utilities around the US—may have a different shape for PGE
+ **As a result, the cost-effectiveness of incremental efficiency as an emissions abatement strategy is a *planning assumption* more than it is an *analytical result***
+ **Developing a measure-based approach to identifying emerging opportunities such as that on the prior slide would allow for improved estimates of program funding costs**

# Cost-Effectiveness Screening in a Low Carbon Future (6)

**6. How should ETO's supply curve cost-effectiveness screening treat the probability of a carbon price under a low carbon future?**

- **ETO currently screens cost-effectiveness of efficiency based on PGE's avoided costs, which currently include no explicit consideration for a future carbon price**
- **Under a low carbon future, ignoring the value of efficiency opportunities just beyond this threshold will inflate the costs of reducing emissions**
- **PGE and ETO should consider how placing an explicit value on emissions reductions would impact its cost-effectiveness threshold for EE**
- **A second cost-effectiveness screening incorporating a carbon price provides another means of distinguishing efficiency as a resource in a low carbon future**

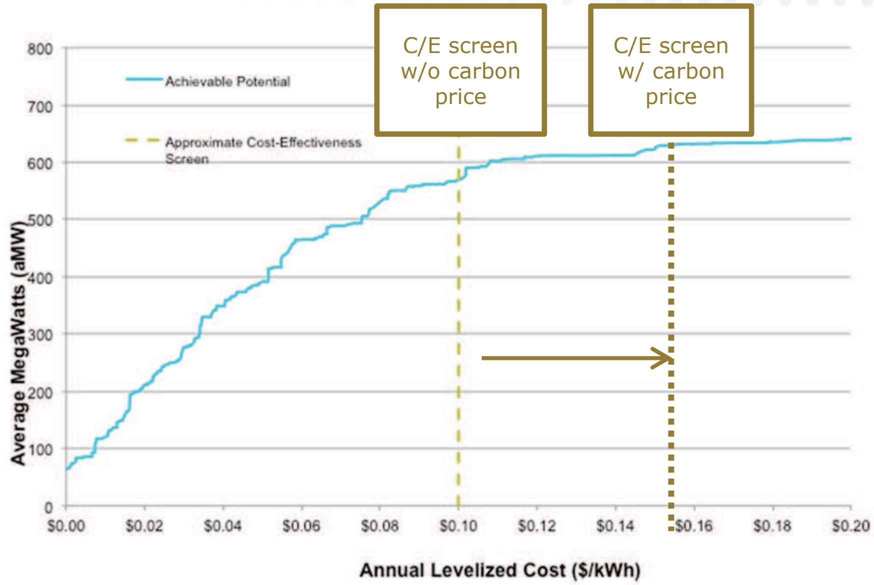



**Figure is illustrative only and shows the impact of carbon pricing on cost-effectiveness screening of energy efficiency**

# Non-Programmatic Efficiency (7)

**7. How can non-programmatic energy efficiency impacts be better captured in load forecasting?**

+ **Like most utilities, PGE forecasts future loads using a top-down model based on the historical relationship between macroeconomic and population indicators and loads**
  - As a result, increasing stringency of codes and standards is not explicitly accounted for in the load forecast
  - At the same time, it is challenging for ETO's efficiency assessment to account for savings through non-programmatic channels
+ **In the future, incorporating end-use detail into the load forecast development would allow for explicit adjustments for future changes to codes and standards, improving the accuracy of the load forecast**

| Examples of Increasing Federal Standards |
|---|
| • By 2014, federal standards will require general purpose lighting to provide 45 lumens per watt |
| • Water heaters larger than 55 gallons will be required to utilize heat pumps |

# EE Substitution Effects (8)

**8. Is there a substitution effect for energy efficiency that results in increased $CO_2$ emissions elsewhere in the economy?**

- **Several studies have found that the adoption of increasingly efficient technologies can cause behavior changes that partially offset the carbon reductions that improvement in efficiency might have otherwise enabled**
  - One example: a person who purchases a fuel-efficient vehicle may drive more than they would have using a less efficient vehicle
- **Determining whether this effect is real—and to what extent it should be considered in a utility's resource planning for carbon reductions—is a challenging exercise**
  - However, ignoring this impact could result in an overvaluation of energy efficiency as a measure to reduce carbon emissions

# Characterizing the Cost of Renewable Integration (9)

**9. How does integration cost change at different penetrations and with different amounts of intermittent resource diversity?**

- **Integration costs refer to the increase in system dispatch costs associated with the need to carry increased levels of reserves to accommodate the intra-hour variability and the uncertainty of renewables**
- **Because integration costs are very difficult to quantify, many studies, including PGE's prior IRPs, assume that the unit cost of integration ($/MWh) for intermittent technologies such as wind and solar PV does not change as penetrations increase**
- **However, there is growing concern in the industry that the unit cost of integration will begin to increase as higher and higher penetrations are achieved**
- **As higher penetrations are reached, understanding the marginal cost of integration and how portfolio diversity affects its magnitude could become instrumental in informing utilities' choices of low cost resources to add to their portfolios**
- **A closely related question is how the GHG impacts of renewable additions will change at varying levels of penetrations**
  - E3's analysis has assumed a 1-for-1 substitution of renewable generation for gas generation
  - However, as penetrations increase, operators will have to utilize less efficient, fast ramping gas resources to provide sufficient reserves to balance variable renewables, which could result in lower GHG reduction efficiency associated with renewable resources

# Understanding the Need for Flexible Resources (10)

**10. At what wind penetration would PGE need to build new flexible capacity solely to balance intra-hour variability of intermittent resources?**

- **One of the major concerns in California as the state approaches its 33% RPS is whether there will be enough flexible generation resources available to meet all of the ramps and reserve requirements resulting from high penetrations of intermittent resources**
- **With PGE's small size and its past and future loss of flexible hydro contracts, it will have to consider the need for flexible resource additions to balance its growing variable energy portfolio**
- **One of the major questions that PGE will have to confront is what type of flexible capacity acquisitions will provide the best complement to its renewable portfolio:**
  - Combined cycle
  - Combustion turbine
  - Demand response
  - Internal combustion engines
  - Storage
  - Smart grid applications

# How Cooperation Among Entities Impacts Costs of Integration (11)

**11. What would be the impact of an EIM or other regional initiatives on PGE's integration cost and flexibility needs?**

+ **Over the past several years, there has been growing interest in the possibility of establishing an Energy Imbalance Market in the WECC**
  - Two recent (2011) studies of benefits of implementing an EIM over a WECC footprint (but excluding CAISO and AESO): one funded by WECC and the other by Public Utilities Commission EIM group
  - CAISO and Pacificorp recently joined in an MOU to implement such an EIM with the express goals of improving dispatch efficiency and reducing integration costs
+ **From PGE's perspective, participating in such a regional initiative could result in benefits to ratepayers whose magnitude could be increased in a low carbon portfolio:**
  - **Reduced reserves cost:** by pooling its loads and renewables with neighboring BAs to take advantage of diversity and by sharing flexible resources to provide reserves more efficiently, PGE could reduce the cost of carrying reserves to balance its increasing penetrations of renewable resources (i.e. its integration costs)
  - **Reduced renewable curtailment:** participating in a larger pool through an EIM would reduce the likelihood of PGE's needing to curtail valuable renewable generation during periods of overgeneration

# Gorge Wind Potential (12)

**12. How much wind in the Columbia River Gorge can PGE expect to be able to develop?**

+ **E3's assessment of wind potential in the Columbia River Gorge relies heavily on the NREL Western Wind Dataset, which has some shortcomings in this context:**
  - It is admittedly not a comprehensive estimate of resource potential, and the data set's broad scope (the entire Western US) may result in a lack of accuracy in such local geography
  - Its resource assessment is now slightly outdated, as improvements in wind turbine technologies—especially performance at low wind speeds—have expanded the possibilities for site selection
+ **Competition among utilities in the Northwest to develop local wind resources in a low carbon future may limit PGE's access to the available potential**
  - Competition for the best renewable resources could be expected to increase in a low carbon future
  - How will this competition for high quality renewables affect regional trends in resource development?

# Transmission Challenges in the Columbia River Gorge (13)

**13. To what extent will the lack of transmission availability constrain development of otherwise viable resources in the Gorge?**

- **E3's analysis suggests that developing wind in the Gorge is one of the lowest cost renewable resource options available to PGE as long as no major additional investments in new transmission are needed**
- **Transmission from the Gorge to Portland's load center on BPA's system may be limited due to the substantial wind development in the region over the past several years**
- **Cascade Crossing could provide relief, providing a new path for east-side resources.**
  - Single circuit 500 kV: ~800 MW for wind after Boardman shuts down
- **Nonetheless, PGE should continue to monitor the situation to understand what upgrades may be needed to continue development in the region and, as a result, whether other resource options may present more cost-effective opportunities**

# Accessing Montana Wind on Colstrip Transmission (14)

**14. In the event of a Colstrip displacement, what technical steps will be necessary to maintain the path rating to allow PGE to access high capacity factor Montana wind?**

+ **E3's analysis has assumed that the ratings of paths that PGE currently uses to deliver Colstrip's generation to its loads could be sustained at minimal cost to PGE in the event of Colstrip's displacement, allowing PGE to acquire roughly 120 MWa of high quality wind resources along this corridor**
+ **Maintaining the path ratings from Montana to Oregon may require additional investments in transmission infrastructure or the introduction of new RAS arming schemes to avoid WECC-wide reliability issues in the event of a contingency**
  - Maintaining the path rating in the absence of a single large coal plant at the end of the line may prove challenging

# Costs of Major New Transmission (15)

**15. What is the magnitude of new investment that will be necessary to access wind in locations that are currently inaccessible to PGE because of transmission constraints?**

+ **The assumptions in E3's analysis suggest that the costs of new transmission are prohibitively high for PGE to consider developing remote wind resources while local renewable resources are available**
  - Based on NWPCC 6th Power Plan assumed transmission costs from Wyoming to Oregon
  - Capacity factor for Wyoming wind is assumed to be 38%
+ **There are, however, a number of reasons that E3 would recommend PGE continue to evaluate such remote wind resources as an option in its IRPs:**
  1. E3's experience suggests that there may be higher quality wind resources available for development in Wyoming with new transmission—up to capacity factors of 45%—in which case Wyoming wind would look much more competitive even with new transmission investment required
  2. Potential supply of local resources may prove shorter than assumed here, in which case investment in major new transmission to develop renewables may be unavoidable
  3. Reaching the 2030 goals that these portfolios target is only a waypoint on a trajectory to deeper carbon reductions by 2050, which will require further resource development
  4. With the potential challenges facing PGE with regard to integration, there may be substantial benefits to adding diversity to its portfolio of resources by including generation linked to a different wind regime—a benefit that has not been considered in this screening
  5. Pacificorp's planned Gateway expansion will reinforce existing east-to-west corridors, and may provide opportunities for other utilities to transport high-quality Wyoming wind to loads in the PNW

# California Solar Resource Options (16)

**16. Should PGE consider including solar PV generation located in a favorable location (e.g. Southern California) and wheeling the power to its system via CAISO?**

+ **While the assumptions on resource cost and value in the IRP indicate that California solar PV is higher on the renewable supply curve than PGE will need to look to achieve low carbon targets, there are a number of reasons that PGE may want to continue to evaluate this resource option:**

  1. The costs of solar PV resources have dropped precipitously in the past several years, and if cost reductions continue in the future, the economics of PV relative to Gorge wind could shift;
  2. Historically, power has flowed along the California-Oregon Intertie from North to South throughout much of the year, suggesting that wheeling power from California to Portland should not be constrained by congestion or a lack of transmission and could reduce real power losses; and
  3. Diversifying its renewable portfolio among multiple technology types could provide PGE benefits that have not been explicitly accounted for in this analysis (e.g. reduced integration costs), and the complementarity of solar and wind production profiles could reduce the challenges associated with serving load under high penetrations of renewables

# Risk of Stranded Assets (17)

**17. Would any of the gas resources that PGE may consider in the development of an Action Plan be at risk of stranding in a Low Carbon future?**

+ **In a carbon-constrained future, utilization of gas-fired resources may be limited by emissions targets, which could result in underutilization of new investments in a low carbon future**
  - Gas investments that may present an apparent low-cost solution to serving loads in the near future could result in higher costs for ratepayers if their use is limited in the future
+ **As gas resources have an expected useful lifetime that spans several decades, it is critical to consider how the constraints of a low carbon future might impact the lifecycle economic impacts of its investment decisions**
  - This could be achieved through the calculation of a value-at-risk analysis, whereby PGE could calculate the incremental cost to its ratepayers of investing in infrastructure that becomes underutilized in the event of a low carbon constraint on the portfolio

# Balance Between Near- and Long-Term Strategies (18)

**18. Are there any near-term actions that PGE should consider taking with the prospect of a low-carbon future on the horizon?**

- While long-term carbon targets often appear to be a long distance in the future, the multi-decade lifetime of new investments requires utilities to plan near-term investments carefully to facilitate the achievement of these goals and allow for flexibility in resource development
- Utilities must continue to balance their focus on near-term investment decisions with a considerations of their long-term implications with respect to carbon dioxide emissions reduction

Energy+Environmental Economics

# Thank You!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| Priority Recommendations from PGE Low Carbon Scenario Analysis<br>[developed by the Environmental Group; based on E3 analysis and suggested subjects for further evaluation.]<br>March 15, 2013 | | | |
|---|---|---|---|
| | Area | Recommendations | Suggested additional parties to involve |
| I | 2013 IRP | PGE should defer any significant resource acquisitions pursuant to this 2013 IRP, relying instead on short-term and medium-term purchases if needed, to preserve its future options to acquire lower carbon resources and to avoid the opportunity cost of committing to a new large fossil-fueled resource. | ODOE, OPUC, NCPPC |
| II | Next Steps | PGE should continue collaborative efforts with other relevant parties to complete research in the areas recommended below over the next two to three years. | |
| | IIa. Improve long-term PGE/ETO Energy Efficiency (EE) Supply Curve | PGE should seek to confirm the low/medium/high probability LBNL EE supply curves identified by E3; in particular:<br>• Leverage NWCPPC backcasting EE supply analysis to have a tool for validating predictions of EE technology maturation and delivery potentials<br>• Identify EE technologies within the low/medium/high probability range and evaluate for potential contributions over the planning horizon (even if it is still "emerging technology" at front end of IRP period)<br>• Evaluate opportunities for EE penetration gains through new | ETO, NCPPC, LBNL |

| | | | |
|---|---|---|---|
| | | behavioral, financing and other delivery mechanisms<br>• Evaluate opportunities for technology availability through new Federal and State efficiency standards (e.g., appliances, lighting, motors, etc.)<br>• Evaluate new incentive and regulatory tools that could enlarge the EE supply curve or accelerate technology/delivery movement through:<br>  o Attributing higher carbon displacement value<br>  o Attributing higher system operations value for load-center EE resources, especially those with dispatchable Demand Response capability | |
| | IIb. Enlarge PGE Renewable Energy Supply Curve | • Evaluate potential for utility scale solar (≥ 10 MW) costs to descend during the IRP 20 year window (as wind did from 2000-2012), and reserve flexibility to acquire such resources during the planning period<br>• Complete and evaluate the closed-loop biomass fuel supply demonstration at the Boardman facility; evaluate forest-fuel recovery and other biomass technology and fuel options.<br>• PGE should fully evaluate and cost out the option of terminating Colstrip early and reassigning the associated transmission assets to developing eastern slope Rocky Mountain wind for its energy and diversity value to the utility.<br>• Evaluate wind options outside the Columbia River corridor development area for resource value, diversity value, cost to access, cost to integrate (see "Colstrip," above; and | NREL, LBNL, BPA, NCPPC, ODOE, ETO |

| | | | |
|---|---|---|---|
| | | "integration supply curve, below)<br>• Evaluate and address access, regulatory or business issues required to capture the geothermal resources in the supply curve<br>• Evaluate new incentive and regulatory tools that could enlarge the RE supply curve or accelerate technology/delivery movement (e.g., through attributing higher carbon displacement value) | |
| | IIc. Enlarge PGE Renewable Energy Integrating Tools/Resources Supply Curve[1] | • Evaluate the range, availability and marginal cost curves of supply side and demand response flexibility options that may become available to support variable generating resources<br>  ○ Load-center and "mine-mouth" supply-side: fast-ramp SCGT; CAES; advanced materials batteries, etc.<br>  ○ Load-center demand-side: load-cycling demand response; plug-in electric vehicles<br>• Evaluate where adding transmission capacity and/or links could offer PGE system flexibility added value<br>• Participate in developing and enlarging a Western Energy Imbalance Market mechanism | WECC, BPA, WAPA, CAISO, NCPPC, NREL, Batelle, LBNL, |

[1] NOTE: The E3 analysis cautions that new integrating capabilities may impose increasing marginal costs on PGE and other utilities. While this may be the case, it is at least equally likely that increased demand for such capabilities will stimulate innovation and declining unit cost curves (as have wind and solar generating technologies, and many control technologies). The already identified potential for PEV's to provide load center storage capability is one example.

# *Appendix G*

## *Characterization of Supply Side Options*

*by Black & Veatch for PGE*

## *Characterization of Supply Side Options - Wind Energy*

*by Black & Veatch for PGE*

## *Cost and Performance Data for Power Generation Technologies*

*by Black & Veatch for NREL*

FINAL REPORT

# CHARACTERIZATION OF SUPPLY SIDE OPTIONS

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B&V FILE NO. 90.0000

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PREPARED FOR

Portland General Electric

22 FEBRUARY 2013

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# Legal Notice

This report was prepared for Portland General Electric ("Client") by Black &Veatch ("Consultant"). In performing the services, Consultant has made certain assumptions or forecasts of conditions, events, or circumstances that may occur in the future. Consultant has taken reasonable efforts to assure that assumptions and forecasts made are reasonable and the basis upon which they are made follow generally accepted practices for such assumptions or projections under similar circumstances. Client expressly acknowledges that actual results may differ significantly from those projected as influenced by conditions, events, and circumstances that actually occur.

# 1.0 Introduction

Black & Veatch has prepared this report to characterize supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs characterized in this report include:

- Integrated Gasification Combined Cycle (IGCC) with Carbon Capture
- 1x0 General Electric (GE) LMS100PA Combustion Turbine
- 6x0 Wartsila 18V50SG Reciprocating Engines
- Solar Photovoltaic (10 MW Fixed Tilt)
- Biomass Combustion (25 MW Bubbling Fluidized Bed)
- Geothermal (20 MW Binary System)
- Pumped Storage Hydroelectric (500 MW Closed Loop)
- Battery Storage (10 MW, 10 MWh Lithium Ion Battery)
- Battery Storage (25 MW, 25 MWh Lithium Ion 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 of each SSO. A full matrix of cost and performance parameters for the nine requested SSOs is provided as Appendix A.

# 2.0 Design Basis and General Assumptions

## 2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch established design basis parameters for each of the SSOs under consideration. For each SSO, 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 (%) | PRIMARY FUEL |
|---|---|---|---|---|---|
| IGCC w/ Carbon Capture | Gasifier: Entrained Flow<br>Combustion Turbine: GE 7F Syngas<br>Carbon Capture: Physical Solvent<br>Emissions Control: $N_2$ Injection, SCR<br>Heat Rejection: Wet Cooling Tower | Baseload | 475 | 80% | Coal |
| 1x0 GE LMS100 PA | Combustion Turbine: LMS100 PA<br>Emissions Control: SCR, CO catalyst<br>Heat Rejection: Wet Cooling Tower | Peaking | 100 | 5% | Natural Gas |
| 6x0 Wartsila 18V50 SG | Recip. Engine: Wartsila 18V50 SG<br>Emissions Control: SCR, CO catalyst<br>Heat Rejection: Wet Cooling Tower | Peaking | 110 | 5% | Natural Gas |
| Solar PV | PV Module: Trina TSM-PA14<br>Insolation Data Site: Redmond, OR | As-Available | 10 | 22% | n/a |
| Biomass Combustion | Boiler: Bubbling Fluidized Bed<br>Emissions Control: SNCR, Fabric Filter<br>Heat Rejection: Wet Cooling Tower | Baseload | 25 | 85% | Wood |
| Geothermal | System: Binary Geothermal System<br>Heat Rejection: Air-Cooled Condenser | Baseload | 20 | 85% | n/a |
| Pumped Storage Hydro | System: Closed Loop | Storage | 500 | n/a | n/a |
| Battery Storage | Battery: Lithium Ion<br>Max. Discharge Period: 60 minutes | Storage | 25 | n/a | n/a |
| Battery Storage | Battery: Lithium Ion<br>Max. Discharge Period: 60 minutes | Storage | 10 | n/a | n/a |

## 2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, general site assumptions employed by Black & Veatch for these SSOs include the following:

- 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 pre-engineered 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

Assumptions associated with capital cost estimates developed by Black & Veatch include the following:

- Capital cost estimates were developed on an engineer, procure, and construct (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- 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.
- A recommended allowance for Owner's costs has been provided for each technology, separately from the EPC capital cost estimates. Potential Owner's costs are listed in Table 2-2.
- All capital cost estimates are presented in 2012 dollars.

**Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects**

| | |
|---|---|
| **Project Development**<br>• Site selection study<br>• Land purchase/rezoning for greenfield sites<br>• Transmission/gas pipeline right-of-way<br>• Road modifications/upgrades<br>• Demolition<br>• Environmental permitting/offsets<br>• Public relations/community development<br>• Legal assistance<br>• Provision of project management | **Owner's Contingency**<br>• Owner's uncertainty and costs pending final negotiation<br>• Unidentified project scope increases<br>• Unidentified project requirements<br>• Costs pending final agreements (i.e., interconnection contract costs)<br><br>**Owner's Project Management**<br>• Preparation of bid documents and the selection of contractors and suppliers<br>• Performance of engineering due diligence<br>• Provision of personnel for site construction management |
| **Spare Parts and Plant Equipment**<br>• Combustion turbine materials, gas compressors, supplies, and parts<br>• Steam turbine materials, supplies, and parts<br>• Boiler materials, supplies, and parts<br>• Balance-of-plant equipment/tools<br>• Rolling stock<br>• Plant furnishings and supplies | **Taxes/Advisory Fees/Legal**<br>• Taxes<br>• Market and environmental consultants<br>• Owner's legal expenses<br>• Interconnect agreements<br>• Contracts (procurement and construction)<br>• Property |
| **Plant Startup/Construction Support**<br>• Owner's site mobilization<br>• O&M staff training<br>• Initial test fluids and lubricants<br>• Initial inventory of chemicals and reagents<br>• Consumables<br>• Cost of fuel not recovered in power sales<br>• Auxiliary power purchases<br>• Acceptance testing<br>• Construction all-risk insurance | **Utility Interconnections**<br>• Natural gas service<br>• Gas system upgrades<br>• Electrical transmission<br>• Water supply<br>• Wastewater/sewer<br><br>**Financing (included in fixed charge rate)**<br>• Financial advisor, lender's legal, market analyst, and engineer<br>• Loan administration and commitment fees<br>• Debt service reserve fund |

### 2.3.1 Direct Cost Assumptions

Assumptions regarding direct costs within the capital cost estimates include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- 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.

### 2.3.2 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 NON-FUEL OPERATION & MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with non-fuel operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- Non-fuel 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.

- Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components.
  - Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
  - Non-fuel Variable O&M costs include outage maintenance, parts and materials, water usage, chemical usage and equipment.
  - Non-fuel Variable O&M costs exclude the cost of fuel (e.g., coal, natural gas or woody biomass). Depending upon the SSO, fuel may or may not be required.
- All Non-fuel O&M cost estimates are presented in 2012 dollars.

## 2.5 ADDITIONAL FINANCIAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including escalation of capital costs (over an extended term); capital expenditures and maintenance accruals; and decommissioning costs.

### 2.5.1 Escalation of Capital Costs (over an Extended Term)

Capital costs for electric power plants have become driven by the current market conditions for commodities, equipment, and construction. As a result, they have become extremely volatile. This volatility makes the application of simple escalation rates over an extended term difficult. Historical power plant capital costs for conventional generation in the United States have been driven by two major events since the late 1990s. The first was the large boom in the combined cycle market that occurred in the late 1990s and the early 2000s. The second major event was the large boom in coal fueled units during the 2000s. Other significant events also contributed to the conventional power plant cost escalation during this period including the boom in proposed nuclear plant construction, the boom in air quality control equipment installation on coal units, and the international conventional generation construction market. An example of this volatility was a 55 percent increase in the capital cost of F class combined cycles entering service in 2000 compared to 1999. Similarly, combined cycles experienced a 60 percent increase in capital cost in the mid- to late 2000s. During the period from 2000 to 2011, however, combined cycle capital costs also decreased in certain years by as much as 13 percent.

On the other hand, evolving technologies such as solar and wind have seen significant reductions in costs during this period in spite of pressure on the EPC market for conventional resources. These market trends are difficult to accurately forecast. As such, Black & Veatch generally employs the expected general inflation rate as a proxy for long-term escalation for planning studies. While there may be periods where market pressures cause short-term fluctuations in capital costs, the general outlook of Black & Veatch regarding capital costs is (1) conventional alternatives will be steady, and (2) renewable alternatives such as solar and wind will slow in their decreasing prices and become steady.

### 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), 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

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, 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).

The fixed amount was determined using a sinking fund factor based on the book life of the asset and an assumed interest rate of 6 percent. The future amount was estimated based on a percentage of the current total capital requirement of the asset. The percentage was based on recent decommissioning cost estimates for similar scope of decommissioning for similar assets.

# 3.0 Conventional Generation Options

Of the SSOs considered in this effort, three are classified as conventional generation options. These include:

- Integrated Gasification Combined Cycle (IGCC) with Carbon Capture
- 1x0 GE LMS100PA Combustion Turbine
- 6x0 Wartsila 18V50SG Reciprocating Engines

These conventional SSOs and their performance and cost characteristics are defined below.

## 3.1 INTEGRATED GASIFICATION COMBINED CYCLE WITH CARBON CAPTURE

### 3.1.1 Technology Overview

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to $CO_2$ to generate sufficient heat for the endothermic gasification reactions.

Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals, and since the mid-1990s, to produce electricity in four 250 to 300 MW IGCC plants located in Europe (two units) and the United States (two units). At this time, based upon their characteristics and level of development, entrained flow gasifiers are the best choice for high capacity gasification for power generation.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf (on an HHV basis). Oxygen is produced in a cryogenic air separation unit (ASU) by compressing air; cooling and drying the air; removing $CO_2$ from the air; chilling the feed air with product oxygen and nitrogen; reducing the air pressure to provide autorefrigeration and liquefy the air at -300 °F; and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

The oxygen produced from the ASU is fed to the gasifier along with coal and fluxant (if needed) to produce raw syngas. The raw syngas is cooled, and then cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents to remove various sulfur and nitrogen containing compounds ($H_2S$, COS, ammonia ($NH_3$), and hydrogen cyanide (HCN)). The clean syngas used as CTG fuel contains hydrogen, CO, carbon dioxide ($CO_2$), water, and low concentrations of hydrogen sulfide ($H_2S$) and carbonyl sulfide (COS).

A representative IGCC process flow diagram (excluding carbon capture) is shown in Figure 3-1.

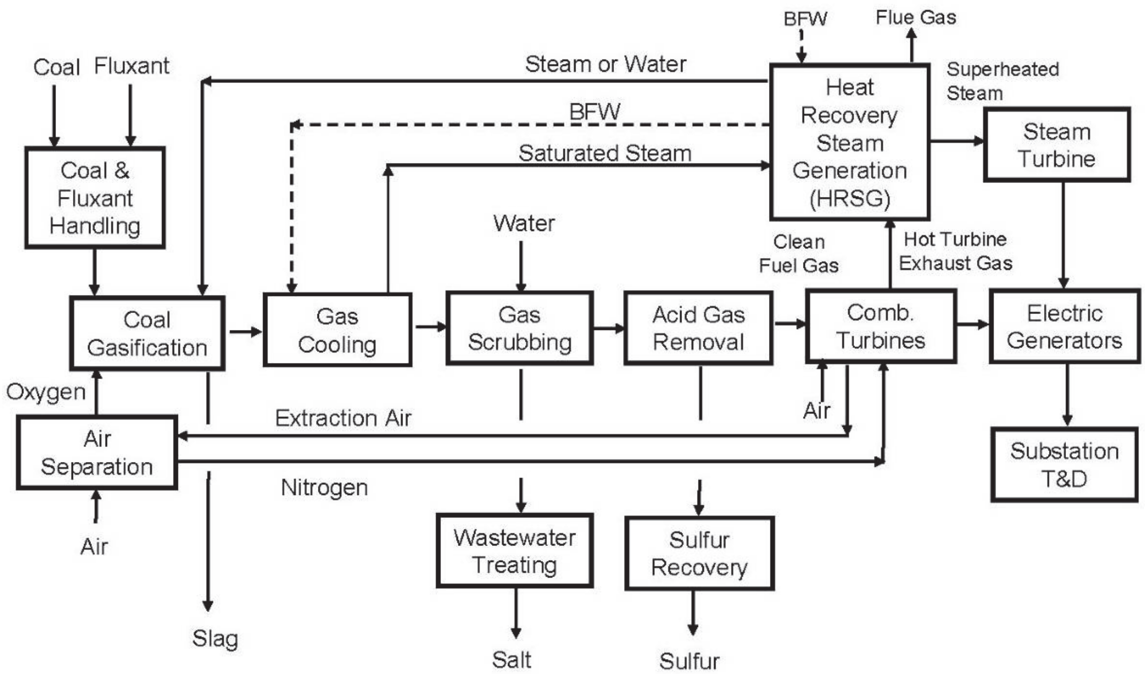



**Figure 3-1 Typical IGCC Process Flow Diagram**

When adding carbon capture to an IGCC plant, the CO in the syngas may be shifted with water to form $CO_2$ and hydrogen by the water-gas shift reaction. The $H_2S$ and $CO_2$ are then removed with acid gas removal (AGR). A physical solvent is used to absorb the $CO_2$ from the hydrogen-rich syngas. Regeneration of the solvent produces a $CO_2$ stream suitable for enhanced oil recovery or other underground storage.

Coal-based operating experience of IGCC systems has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., Powder River Basin [PRB]) coals have been tested only in a limited fashion, but due to the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. The assumed fuel for this study is PRB.

Presently, leading technology suppliers for entrained flow gasification processes associated with IGCC configurations include the following:

- General Electric (GE)
- Phillips 66 (P66)
- Shell
- Siemens

One of the primary differences between these gasification technologies is in the feeding system: dry feed versus wet (slurry) feed systems. GE and P66 technologies employ wet feed systems, while Shell and Siemens technologies employ dry feed systems.

Dry-feed gasification processes are better suited for high moisture fuels (e.g., PRB, the assumed design fuel for this study), as these processes minimize the moisture added to the gasifier (beyond the inherently high moisture of the fuel). Because these dry-feed processes are better suited for PRB, the Shell process was selected as the likely gasification technology for this characterization.

Entrained flow gasification processes may offer the potential to co-fire biomass fuels, but the extent to which this may be possible is largely dependent upon the feed system of the technology. Wet feed systems (e.g., GE and P66) would limit biomass co-firing to a range of 0 to 5 percent (by weight) of the total fuel stream. Dry feed systems (e.g., Shell and Siemens) may be able to co-fire biomass in the range of 10 to 30 percent (by weight) of the total fuel stream, with system design modifications required to achieve the upper end of this range. Biomass has been reportedly used as a successful co-feed for the Shell gasification process employed at Nuon Power's 235 MW (net) IGCC power plant located in Buggenum, The Netherlands, with biomass representing up to 30 percent (by weight) of the fuel input to the gasifier. Biomass used at Buggenum has included pre-milled waste wood, dried sludge from biotreaters, paper mill wastes, and chicken manure. In order for successful co-firing, the biomass should be (1) relatively dry and (2) pre-milled or easily millable to a size comparable to coal powder.

### 3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a baseload IGCC plant with carbon capture and compression. Relevant assumptions employed in the development of performance and cost parameters for the IGCC plant include the following:

- The IGCC facility would have a net generation capacity of 495 MW and a capacity factor of approximately 80 percent.
- The IGCC facility is based on the Shell gasification technology.
- Major equipment for the IGCC system (with carbon capture) includes:
  - (2) GE 7F Syngas combustion turbines
  - (2) Shell entrained flow gasifiers
  - (1) Condensing steam turbine generator
  - (1) Acid gas removal system
  - (1) Cooling tower
  - (1) Air separation unit
- Carbon capture equipment is designed and sized for $CO_2$ capture efficiency of 90 percent.
- $CO_2$ transportation and sequestration are not included in the overnight EPC capital cost.

## 3.2 1X0 GE LMS100PA

### 3.2.1 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. $NO_x$ 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 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 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.

### 3.2.2 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 $NO_x$ and 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.

## 3.3 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. The 18V50SG is based on the smaller 20V34SG model, with almost 400 engines in operation to date.

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 100 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 $NO_x$ and CO emissions.
- Engine heat is rejected to atmosphere by way of a common wet mechanical draft cooling tower.

## 3.4 TECHNICAL AND FINANCIAL PARAMETERS FOR CONVENTIONAL GENERATION OPTIONS

Technical parameters for conventional energy options considered for PGE are summarized in Table 3-1, while cost and financial parameters for conventional energy options considered for PGE are summarized in Table 3-2 and Table 3-3.

**Table 3-1 Technical Parameters for Conventional Generation Options**

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | LAND REQUIRED (ACRES) | NET PLANT HEAT RATE (BTU/ kWh) | MINIMUM TURNDOWN CAPACITY (%) | RAMP RATE (MW/MIN) | WATER CONSUMPTION (MGD) | SCHEDULED MAINTENANCE PATTERN (WEEKS/YR) | EQUIVALENT FORCED OUTAGE RATE (%) |
|---|---|---|---|---|---|---|---|---|---|
| Integrated Gasification Combined Cycle (w/ $CO_2$ Capture) | 475(1) | 80(2) | 60 | 11,900(1) | 25 | 10 | 6.5 | 3-3-3-3-3-4 | 13 |
| 1x0 LMS100 | 100 | 5 | 10 | 9,000 | 30 | 50 | 0.5 | 1-10 | 1.6 |
| 6x0 Wartsila 18V50 | 110 | 5 | 7 | 8,400 | 7 | 12 | 0.4 | 2-3-2-3-2-4 | 3.2 |

(1) When operating with a $CO_2$ capture efficiency of 90%, the IGCC w/ $CO_2$ Capture facility would provide a net capacity of 475 MW and a net plant heat rate (NPHR) of approximately 11,900 Btu/kWh. When operating in a mode without CO Capture, the IGCC facility would provide a net capacity of 560 MW and an NPHR of approximately 9,000 Btu/kWh.

(2) IGCC w/ $CO_2$ Capture capacity factor assuming 100 percent utilization and based on expected long term plant availability after the first several years of operation. Plant availability is expected to be 70-75 percent for the first five years of operation.

### Table 3-2 Financial Parameters for Conventional Generation Options

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | BOOK LIFE (YEARS) | EPC PROJECT DURATION[1] (MONTHS) | EXPENDITURE PATTERN | OVERNIGHT EPC CAPITAL COST ($000, 2012$) | OWNER'S COST ALLOWANCE (%) | OVERNIGHT TOTAL CAPITAL COST ($000, 2012$) |
|---|---|---|---|---|---|---|---|---|
| Integrated Gasification Combined Cycle (w/ $CO_2$ Capture) | 475 | 80 | 35 | 59 | See Appendix B | 2,900,000 | 20 | 3,480,000 |
| 1x0 LMS100 | 100 | 5 | 25 | 24 | See Appendix B | 107,000 | 25 | 133,750 |
| 6x0 Wartsila 18V50 | 110 | 5 | 25 | 24 | See Appendix B | 145,000 | 25 | 181,250 |

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

### Table 3-3 Financial Parameters for Conventional Generation Options – Continued

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | FIXED O&M COSTS ($/kW-YEAR) | NON-FUEL VARIABLE O&M COST ($/MWh) | DECOMMISSIONING ACCRUAL[1] (2012$) | LONG-TERM CAPITAL COST ESCALATION RATE[2] |
|---|---|---|---|---|---|---|
| Integrated Gasification Combined Cycle (w/ $CO_2$ Capture) | 495 | 80 | 64.9 | 11.4 | 5,500,000 | General Inflation |
| 1x0 LMS100 | 100 | 5 | 12.7 | 3.6 | 150,000 | General Inflation |
| 6x0 Wartsila 18V50 | 110 | 5 | 15.7 | 8.6 | 185,000 | General Inflation |

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition.
(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

# 4.0 Renewable Generation Options

Renewable SSOs considered for this effort include:

- Solar Photovoltaic (10 MW Fixed Tilt)
- Biomass Combustion (25 MW Bubbling Fluidized Bed)
- Geothermal (20 MW Binary System)

These renewable SSOs and their performance and cost characteristics are defined in the following sections.

## 4.1 SOLAR PHOTOVOLTAIC

### 4.1.1 Technology Overview

Photovoltaic (PV) systems convert sunlight directly into electricity. The conversion of sunlight into electricity (known as the photovoltaic effect), is achieved with semiconductor materials. There are three main types of commercially available PV technologies to date. These are: crystalline Silicon (c-Si) modules, thin-film modules and concentrating PV systems. The most widely used technology is c-Si, which is also the technology with the longest operational history, dating back to over 30 years.

The c-Si modules are made up of individual solar cells connected electrically in series. The cells are then encapsulated with a polymer material (typically EVA) that protects them from moisture. The flat sheet of encapsulated cells is mounted on a rectangular back pane sheet made of Teflon or similar material. On the front of the encapsulant there is a flat sheet of transparent glass that allows the transmission of sunlight. The glass is built with optical properties suited for this application and mechanical properties that will withstand hail and other shocks. All these layers are mechanically supported by an aluminum frame.

The amount of power produced by PV modules depends on the technology used and the intensity of the solar radiation incident on the material.

There are two main c-Si technologies, mono-crystalline (m-Si) and poly-crystalline (p-Si). Mono-crystalline cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. Commercial modules built with m-Si cells have efficiencies between 15.5 to 20 percent. Polycrystalline cells have reduced production costs, but provide a lower efficiency of 14 to 15.8 percent. The thermal response (power output as a function of temperature) of m-Si modules is also better than p-Si modules.

Thin film technology was able to significantly reduce module's price in the past few years. However, c-Si prices in the last year have reduced the price gap difference, leaving a minimal margin between both technologies. Thin film technologies have a lower efficiency (approximately 7 percent to approximately 13 percent) although the thermal response is significantly better than the m-Si modules. Currently, most thin-film modules are made of two different semiconductors alloys: Cadmium Telluride (CdTe) and Copper Indium Gallium Selenide (CIGS). Thin film modules have similar warranties to crystalline modules, but due to the limited operating experience there is some uncertainty regarding their degradation (of performance) over time.

Concentrating PV systems (CPV) make use of highly efficient cells (over 35 percent). The cost per unit area of these cells is significantly higher when compared with c-Si cells or thin film modules. However, the use of concentration reduces the material requirements and typical CPV cells have a surface area of one square centimeter. For most commercial cases, a CPV system requires to be installed in regions with high solar resource and clear skies to be cost effective. These regions tend to be arid, desert like areas like the southwest of the United States. There are few commercial CPV installations worldwide

To calculate the expected energy output of a PV system the most important input is the solar resource. A typical solar resource metric is the total amount of solar radiation incident on a horizontal plane and measured in kWh/$m^2$ on a yearly basis. Because this metric captures the radiation incident from all angles on this plane, it is referred to as Global Horizontal Irradiance, or GHI.

There are few data sources available for the United States. The National Renewable Energy Laboratories (NREL) has compiled three main datasets that are publicly available, which are TMY2, TMY3 and TGY. There are also private companies that sell data sets based on satellite image data. The data sets are compiled as a Typical Meteorological Year (TMY) with hourly values, for a total of 8760 data points per TMY. The TMY data set is meant to be representative of a typical year and is compiled from several years of measured data, using a specific algorithm that filters out atypical records and takes into account the inter-annual variability observed in the series. In general, inter-annual variability is less than 3 percent for most US locations.

For the specific location under review (Redmond, Oregon) the typical GHI (from TMY2 file) is 1,620 kW/$m^2$. In comparison, typical GHI for the southwest United States is approximately 2,100 kW/$m^2$.

### 4.1.2 Technology-Specific Assumptions

Cost and performance have been developed for a utility-scale PV system. The utility-scale PV system is assumed to be a 10 MWac system using crystalline Silicon modules mounted at a fixed tilt. Relevant assumptions employed in the development of performance and cost parameters for the 10 MW utility-scale solar PV system include the following:

- The PV system model was developed with PVsyst software version 5.60. PVsyst is an industry standard modeling tool for PV systems developed by the University of Geneva in Switzerland.
- The specific commercial equipment selected for the purposes of conceptual design, system modeling and cost estimates is representative of Tier-1 manufacturers. The remaining balance of systems equipment and materials were assumed to be typical for this type of projects. The specific equipment used in this study does not imply a recommendation on the part of Black & Veatch to select or engage with any of these vendors.

- The model was based on a conceptual system design with the characteristics listed in Table 4-1.

**Table 4-1 Solar PV Conceptual System Design Parameters for Performance Modeling**

| PARAMETER | VALUE |
|---|---|
| System DC Rating (MW dc) | 12.47 |
| System AC Rating (MW ac) | 10.08 |
| System DC voltage (V) | 1000 |
| Module nominal power (W) | 300 (Trina TSM-PA14) |
| Modules per string | 18 |
| Total number of modules | 41,580 |
| Inverter nominal power (KW ac) | 720 (SMA SC 720CP-US) |
| Number of inverters | 14 |
| Tilt (degrees) | 27 |
| Surface area (acres) | 52 |
| Acres / MW ac | 5.2 |

- The solar resource data selected was the TMY2 data set from NREL for Redmond/Bend.
- The model included typical losses due to wiring, module mismatch and others, as well as estimated soiling based on the average weather patterns observed in Redmond. Shading losses were considered minimal.
- The EPC costs model assumed the main characteristics listed below:
- The site is relatively flat and is a single parcel of a regular shape. Minimal grading is required. There is minimal vegetation to be removed. No drainage works were assumed to be required on this site.
  - The foundations for the mounting structures are hot dip galvanized I-beams installed as driven piles.
  - The geological conditions are assumed to be optimal for driven piles. The soils are solid/hard, well compacted and with medium density. These conditions allow for shorter driven piles with strong frictional forces in the long term to ensure minimal displacement of the pile. Assuming soft soils or hard rock would have increased project cost. The soils are assumed to be non-corrosive.
- The installation is assumed to be performed by an experienced solar integrator. An experience solar integrator provides:

- Efficient design and construction processes.
- Most economical equipment pricing from vendors.

- The interconnection is at distribution voltage with no step-up transformer required.
- The AC collector station is next to the point of interconnection.

## 4.2 BIOMASS COMBUSTION

### 4.2.1 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 $/MBtu 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 nitrogen oxides ($NO_x$), particulate matter (PM), and carbon monoxide (CO) to meet state and or federal regulatory requirements.

### 4.2.2 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 25 MW. Relevant assumptions employed in the development of performance and cost parameters for the 25-MW 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.
- The facility will have a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes Selective Non-Catalytic Reduction (SNCR) systems for $NO_x$ control, sorbent injection for acid gas control, and a fabric filter for particulate matter (PM) control.

## 4.3 GEOTHERMAL

### 4.3.1 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.[1] Today, roughly 70 geothermal power facilities are in operation in over 20 countries around the world. There is a

[1] 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.

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.[2]

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 of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

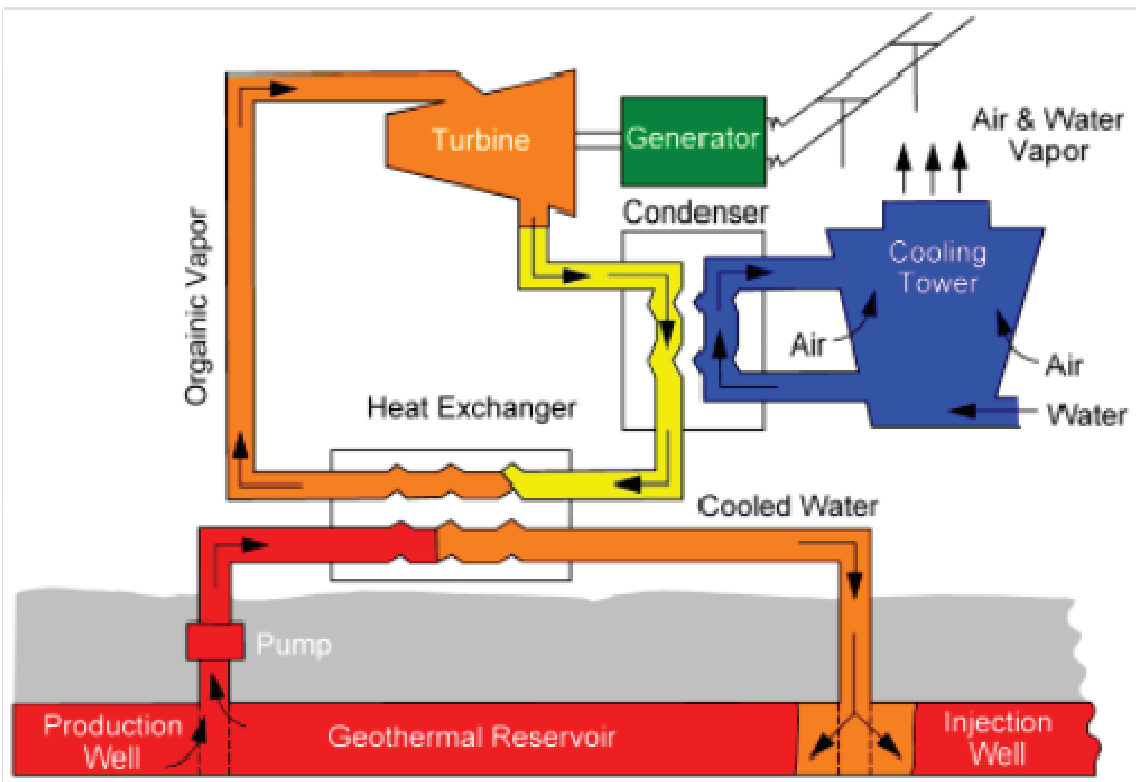
- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350°F [177°C]) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following 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

[2] R.Bertani. (2010). Geothermal Power Generation in the World, 2005-2010 update report. Proceedings of the World Geothermal Congress. Bali, Indonesia.

(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 20-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.

### 4.3.2 Technology-Specific Assumptions

Relevant assumptions employed in the development of performance and cost parameters for the 20-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 20 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.

## 4.4 TECHNICAL AND FINANCIAL PARAMETERS FOR RENEWABLE GENERATION OPTIONS

Technical parameters for renewable energy options considered for PGE are summarized in Table 4-2, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 4-3 and Table 4-4.

**Table 4-2 Technical Parameters for Renewable Generation Options**

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | LAND REQUIRED (ACRES) | HEAT RATE (BTW/ kWh) | MINIMUM TURNDOWN CAPACITY (%) | RAMP RATE (MW/MIN) | WATER CONSUMPTION (MGD) | SCHEDULED MAINTENANCE PATTERN (WEEKS/YR) | EQUIVALENT FORCED OUTAGE RATE (%) |
|---|---|---|---|---|---|---|---|---|---|
| Solar PV | 10 | 22 | 52 | N/A | N/A(1) | N/A | 0.00(2) | 2 | N/A |
| Biomass Combustion | 25 | 85 | 25 | 13,250 | 25 | 1.3 | 0.5(2) | 3-3-3-3-3-8 | 7.5 |
| Geothermal | 20 | 85 | 20 | N/A | 10 | 3.0 | 0.05(2) | 3-3-3-3-3-8 | 6.0 |

(1) If it is necessary to curtail solar power output, the inverter is capable of curtailing 100% of the power output.

(2) For Solar PV, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other water consumption required for operation of Solar PV facility. For Biomass Combustion, water consumption includes makeup water for cooling tower, makeup water for steam cycle, and service water for facility. For Geothermal, water consumption includes service water for facility.

### Table 4-3 Financial Parameters for Renewable Generation Options

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | BOOK LIFE (YEARS) | EPC PROJECT DURATION[1] (MONTHS) | EXPENDITURE PATTERN | OVERNIGHT EPC CAPITAL COST ($000, 2012$) | OWNER'S COST ALLOWANCE (%) | OVERNIGHT TOTAL CAPITAL COST ($000, 2012$) |
|---|---|---|---|---|---|---|---|---|
| Solar PV | 10 | 22 | 25 | 3 | See Appendix B | 24,500 | 12 | 27,440 |
| Biomass Combustion | 25 | 85 | 25 | 36 | See Appendix B | 148,700 | 25 | 185,900 |
| Geothermal | 20 | 85 | 30 | 48 | See Appendix B | 146,000 | 20 | 175,200 |

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

### Table 4-4 Financial Parameters for Renewable Generation Options – Continued

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | FIXED O&M COST ($/kW-YEAR) | NON-FUEL VARIABLE O&M COST ($/MWh) | DECOMISSIONING ACCRUAL[1] (2012$) | LONG-TERM CAPITAL COST ESCALATION RATE[2] |
|---|---|---|---|---|---|---|
| Solar PV | 10 | 22 | 18.0 | 2.6 | 100,000 | General Inflation |
| Biomass Combustion | 25 | 85 | 220 | 9.3 | 530,000 | General Inflation |
| Geothermal | 20 | 85 | 205 | 21.4 | 300,000 | General Inflation |

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition.
(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

# 5.0 Energy Storage Options

Energy Storage options considered for this effort include:

- Pumped Storage Hydroelectric (500 MW Closed Loop)
- Battery Storage (10 MW, 10 MWh Lithium Ion Battery)
- Battery Storage (25 MW, 25 MWh Lithium Ion Battery)

These energy storage options and their performance and cost characteristics are defined in the following sections.

## 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 500 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 500 MW, with a maximum discharge period of 40 hours (i.e., maximum energy storage capacity of 20,000 MWh).
- The facility would employ two reversible pump turbines, each rated at approximately 2,200 cubic feet per second (cfs). These reversible pump turbines are assumed to be located in an aboveground powerhouse near the lower reservoir. Two steel penstocks, each with a diameter of 14 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: 2500 ft above mean sea level (ft msl)
  - Active Water Storage Capacity: 14,500 acre-feet
  - Active Water Storage Depth: 50 ft
- Lower Reservoir design parameters:
  - Elevation: 1000 ft msl
  - Active Water Storage Capacity: 14,500 acre-feet
  - Active Water Storage Depth: 50 ft
- Gross Head design parameters:
  - Average Gross Head: 1500 ft
  - Maximum Gross Head, (Generating or Pumping): 1550 ft
  - Minimum Gross Head, (Generating or Pumping): 1450 ft
- Distance from Upper Reservoir to Lower Reservoir: 1500 ft (i.e., distance/head ratio of 1.0)
- Fixed O&M costs include the cost of major overhaul of the reversible 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.[3]

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 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 10-15 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:

[3] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

- 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 80 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,[4] this section will focus on Li-ion battery technology.

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 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 56 MW.[5]

A summary of representative performance parameters for battery energy storage systems employing Li-ion batteries is provided in Table 5-1.

### 5.2.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for 10-MW and 25-MW battery energy storage systems, each capable of discharging at their rated power for 1 hour. 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.
- Energy storage capacity is based on charge and discharge rate of 1C.

[4] 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.
[5] DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org/

**Table 5-1 Representative Performance Parameters for Lithium Ion Energy Storage Systems**

| PARAMETER | VALUE |
|---|---|
| Commercial Availability | Commercial |
| Facility Power Rating, MW | 0.1 to 32 |
| Module Power Rating, MW | 0.1 to 4 |
| Facility Energy Capacity, MWh | 0.1 to 25 |
| Module Energy Capacity, MWh | 0.1 to 2 |
| Ramp Rate, MW/min | Note (1) |
| Response Time(2) | 20 to 120 ms |
| Round-Trip Efficiency, % | 75 to 90 |
| Discharge Duration, hours | 0.25 to 4 |
| Charge/Discharge Rate, C(3) | 1C to 6C |

(1) Li-ion 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 and Table 5-4. Additional parameters specific to energy storage options are shown in Table 5-5.

### Table 5-2 Technical Parameters for Energy Storage Options

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | LAND REQUIRED (ACRES) | NET PLANT HEAT RATE (BTW/ kWh) | MINIMUM TURNDOWN CAPACITY (%) | RAMP RATE (MW/MIN) | WATER CONSUMPTION (MGD) | SCHEDULED MAINTENANCE PATTERN (WEEKS/YR) | EQUIVALENT FORCED OUTAGE RATE (%) |
|---|---|---|---|---|---|---|---|---|---|
| Pumped Storage Hydro | 500 | N/A | 600 | N/A | 20 | 160 | N/A | 2 | N/A |
| Battery Storage – Spinning Reserve | 25 | N/A | 0.7 | N/A | 0 | Note (1) | N/A | 2 | N/A |
| Battery Storage – Spinning Reserve | 10 | N/A | 0.3 | N/A | 0 | Note (1) | N/A | 2 | N/A |

(1) Li-ion systems 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 | NET CAPACITY (MW) | CAPACITY FACTOR (%) | BOOK LIFE (YEARS) | EPC PERIOD (MONTHS) | EXPENDITURE PATTERN | OVERNIGHT EPC CAPITAL COST ($000, 2012$) | OWNER'S COST ALLOWANCE (%) | OVERNIGHT TOTAL CAPITAL COST ($000, 2012$) |
|---|---|---|---|---|---|---|---|---|
| Pumped Storage Hydro | 500 | N/A | 30 | 60 | See Appendix B | 1,000,000 | 25 | 1,250,000 |
| Battery Storage – Spinning Reserve | 25 | N/A | 20 | 15 | See Appendix B | 48,050 | 12 | 53,820 |
| Battery Storage – Spinning Reserve | 10 | N/A | 20 | 15 | See Appendix B | 21,250 | 12 | 23,800 |

### Table 5-4 Financial Parameters for Energy Storage Options – Continued

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | FIXED O&M COSTS ($/kW-YEAR) | NON-FUEL VARIABLE O&M COST ($/MWh) | DECOMISSIONING ACCRUAL[1] (2012$) | LONG-TERM CAPITAL COST ESCALATION RATE[3] |
|---|---|---|---|---|---|---|
| Pumped Storage Hydro | 500 | N/A | 5.3 | 0.3 | 115,000 | General Inflation |
| Battery Storage – Spinning Reserve | 25 | N/A | 6 | N/A | 50,000 | General Inflation |
| Battery Storage – Spinning Reserve | 10 | N/A | 10 | N/A | 50,000 | General Inflation |

(1) Accrual collected annually over the book life of the asset to decommission the facility. For Battery Storage options, site would be returned to a Brownfield condition. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and facility/reservoirs would be retired in place, with site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).

(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

Table 5-5 Additional Parameters for Energy Storage Options

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | ENERGY CAPACITY (MWh) | DISCHARGE PERIOD (HOURS) | ROUND TRIP EFFICIENCY (%) | CYCLE LIFE – FOR BATTERY OPTIONS (CYCLES) |
|---|---|---|---|---|---|---|
| Pumped Storage Hydro | 500 | N/A | 20,000 | 40 | 77 | N/A |
| Battery Storage – Spinning Reserve | 25 | N/A | 25 | 1 | 85 | 7,000 to 10,000(1) |
| Battery Storage – Spinning Reserve | 10 | N/A | 10 | 1 | 85 | 7,000 to 10,000(1) |

(1) Cycle life assumes a typical cycle of charge to 100% SOC and discharge to 80% DoD.

# Appendix A. Supply Side Option Parameters (Full Table)

| No. | Option | Option Design Basis | Duty | Net Capacity (MW) | Capacity Factor (%) | Primary Fuel | Land Required (acres) | Net Plant Heat Rate (Btu/kWh) | Minimum Turndown Capacity (%) | Range of Potential NPHR Improvements (%) | Ramp Rate (MW/min) | Water Consumption (mgd) | Scheduled Maint. Pattern (weeks/yr) | Equiv. Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Design Basis Parameters | | | | | Technical/Performance Parameters | | | | | | | |
| 1 | Integrated Gasification Combined Cycle (w/ CO2 Capture) | Gasifier: Dry Feed Entrained Flow<br>Combustion Turbine: GE 7F Syngas<br>Carbon Capture: Physical Solvent (90% Capture)<br>Emissions Control: $N_2$ Injection, SCR<br>Heat Rejection: Wet Cooling Tower | Baseload | 475[1] | 80%[2] | Coal (Powder River Basin) | 60 | 11,900[1] | 25% | Note [3] | 10 | 6.48 | 3-3-3-3-3-4 | 13% |
| 2 | 1x0 LMS100 | Combustion Turbine: LMS100 PA<br>Duct Firing: None<br>Emissions Control: SCR, CO catalyst<br>Heat Rejection: Wet Cooling Tower | Peaking | 100 | 5% | Natural Gas | 10 | 8,950 | 30% | Note [3] | 50 | 0.48 | 1-10 | 1.6% |
| 3 | 6x0 Wartsila 18V50 | Recip. Engine: Wartsila 18V50 SG<br>Heat Rejection: Air-cooled radiators<br>Emissions Control: SCR, CO catalyst<br>Heat Rejection: Wet Cooling Tower | Peaking | 110 | 5% | Natural Gas | 7 | 8,370 | 7% | Note [3] | 12 | 0.42 | 2-3-2-3-2-4 | 3.2% |
| 4 | Solar PV -- Fixed Tilt | PV Module: Trina TSM-PA14<br>Insolation Data Site: Redmond, OR | As-Available | 10 | 22% | n/a | 52 | n/a | n/a | Note [3] | n/a | 0.00 | 2 | n/a |
| 5 | Biomass Combustion | Boiler: Bubbling Fluidized Bed<br>Emissions Control: SNCR, Fabric Filter<br>Heat Rejection: Wet Cooling Tower | Baseload | 25 | 85% | Wood | 25 | 13,250 | 25% | Note [3] | 1.3 | 0.53 | 3-3-3-3-3-8 | 7.5% |
| 6 | Geothermal -- Binary | System: Binary Geothermal System<br>Heat Rejection: Air-Cooled Condenser | Baseload | 20 | 85% | n/a | 20 | N/A | 10% | Note [3] | 3 | 0.05 | 3-3-3-3-3-8 | 6% |
| 7 | Pumped Storage Hydro | System: Closed Loop | Storage | 500 | n/a | n/a | 600 | n/a | 20 | Note [3] | 160 | n/a | 2 | n/a |
| 8 | Battery Storage -- Frequency Regulation | Battery: Lithium Ion<br>Max. Discharge Period: 60 minutes | Storage | 25 | n/a | n/a | 0.7 | n/a | 0% | Note [3] | Note [8] | n/a | 2 | n/a |
| 9 | Battery Storage -- Frequency Regulation | Battery: Lithium Ion<br>Max. Discharge Period: 60 minutes | Storage | 10 | n/a | n/a | 0.3 | n/a | 0% | Note [3] | Note [8] | n/a | 2 | n/a |

NOTES:

(1) When operating with a CO2 capture efficiency of 90%, the IGCC w/ CO2 Capture facility would provide a net capacity of 475 MW and a net plant heat rate (NPHR) of approximately 11,900 Btu/kWh. When operating in a mode without CO Capture, the IGCC facility would provide a net capacity of 560 MW and an NPHR of approximately 9,000 Btu/kWh.

(2) IGCC w/ $CO_2$ Capture capacity factor assumes 100 percent utilization and is based on expected long term plant availability after the first several years of operation. Plant availablity is expected to be 70 - 75 percent for the first 5 years of operation.

(3) For all of the SSOs under consideration for the PGE study, Black & Veatch anticipates no significant improvements in efficiency in either the near- or long-term.

(4) 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.

(5) 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.

(6) Decommissioning Accrual collected annually over the book life of the asset to decommission the facility. For all SSOs except Pumped Storage Hydro, 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).

(7) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

(8) Li-ion systems are able to ramp up from an idle status to full rated capacity in less than 1 second.

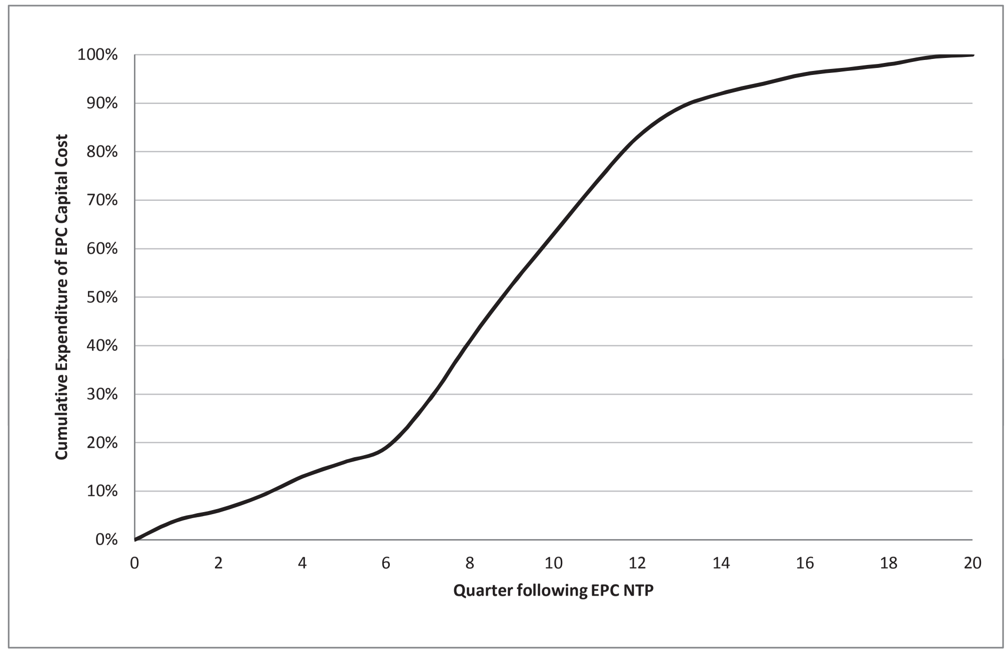
(9) Cycle life assumes a typical cycle of charge to 100% SOC and discharge to 80% DoD.

| No. | Option | Financial Parameters: Book Life (years) | EPC Period[4] (months) | Expenditure Pattern (by month/qtr) | Overnight EPC Capital Cost ($000, 2012$) | Owner's Cost Allowance (%) | Overnight Total Capital Cost ($000, 2012$) | Fixed O&M Cost ($/kW-year) | Variable O&M Cost ($/MWh) | Capital Additions/ Maint. Accrual ($/yr) | Decom-missioning Accrual[6] ($000/yr) | Capital Cost Escalation Rate[7] | Energy Storage Parameters: Energy Capacity (MWh) | Discharge Period (hours) | Round Trip Efficiency (%) | Cycle Life -- for Battery Options (cycles) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Integrated Gasification Combined Cycle (w/ CO2 Capture) | 35 | 59 | See Appendix B | 2,900,000 | 20% | 3,480,000 | 64.9 | 11.4 | Note [5] | 5,500 | General Inflation | n/a | n/a | n/a | n/a |
| 2 | 1x0 LMS100 | 25 | 24 | See Appendix B | 107,000 | 25% | 133,750 | 12.7 | 3.6 | Note [5] | 150 | General Inflation | n/a | n/a | n/a | n/a |
| 3 | 6x0 Wartsila 18V50 | 25 | 24 | See Appendix B | 145,000 | 25% | 181,250 | 15.7 | 8.6 | Note [5] | 185 | General Inflation | n/a | n/a | n/a | n/a |
| 4 | Solar PV -- Fixed Tilt | 25 | 3 | See Appendix B | 24,500 | 12% | 27,440 | 18.0 | 2.6 | Note [5] | 100 | General Inflation | n/a | n/a | n/a | n/a |
| 5 | Biomass Combustion | 25 | 36 | See Appendix B | 148,700 | 25% | 185,900 | 220.0 | 9.3 | Note [5] | 530 | General Inflation | n/a | n/a | n/a | n/a |
| 6 | Geothermal -- Binary | 30 | 48 | See Appendix B | 146,000 | 20% | 175,200 | 205.0 | 21.4 | Note [5] | 300 | General Inflation | n/a | n/a | n/a | n/a |
| 7 | Pumped Storage Hydro | 30 | 60 | See Appendix B | 1,000,000 | 25% | 1,250,000 | 5.3 | 0.3 | Note [5] | 115 | General Inflation | 20,000 | 40 | 77 | n/a |
| 8 | Battery Storage -- Frequency Regulation | 20 | 15 | See Appendix B | 48,050 | 12% | 53,820 | 6.0 | N/A | Note [5] | 50 | General Inflation | 25 | 1 | 85 | 7,000 to 10,000[9] |
| 9 | Battery Storage -- Frequency Regulation | 20 | 15 | See Appendix B | 21,250 | 12% | 23,800 | 10.0 | N/A | Note [5] | 50 | General Inflation | 10 | 1 | 85 | 7,000 to 10,000[9] |

# Appendix B. SSO Expenditure Patterns

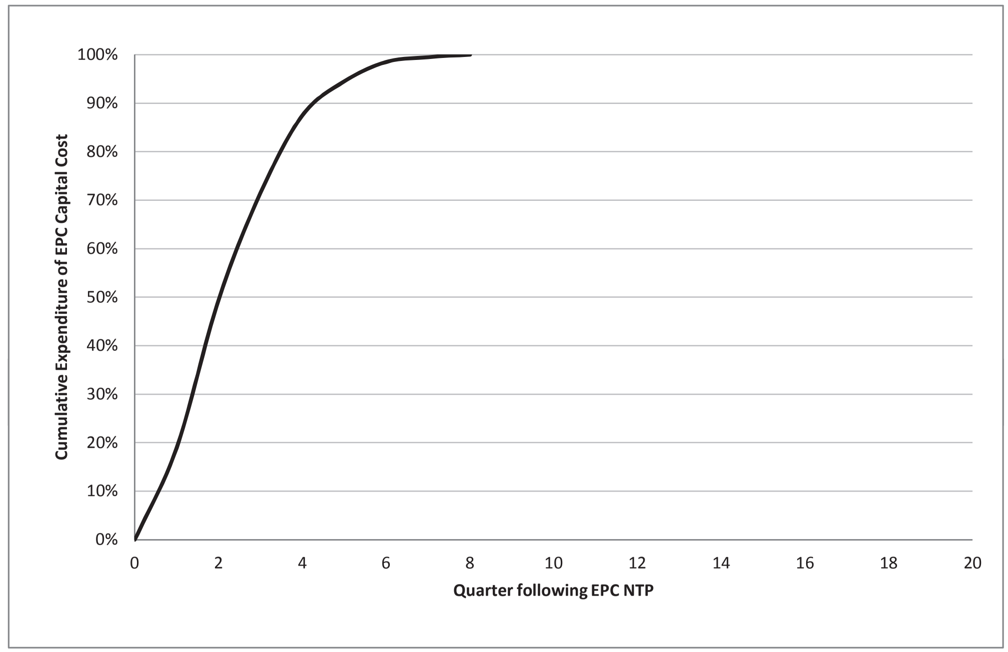
## Expenditure Pattern for EPC Capital Cost
### Supply Side Option: 465 MW IGCC w/ Carbon Capture

| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 4.0% | 4.0% |
| 1 | 2 | 2 | 2.0% | 6.0% |
| 1 | 3 | 3 | 3.0% | 9.0% |
| 1 | 4 | 4 | 4.0% | 13.0% |
| 2 | 1 | 5 | 3.0% | 16.0% |
| 2 | 2 | 6 | 3.0% | 19.0% |
| 2 | 3 | 7 | 9.5% | 28.5% |
| 2 | 4 | 8 | 12.5% | 41.0% |
| 3 | 1 | 9 | 11.5% | 52.5% |
| 3 | 2 | 10 | 10.5% | 63.0% |
| 3 | 3 | 11 | 10.5% | 73.5% |
| 3 | 4 | 12 | 9.5% | 83.0% |
| 4 | 1 | 13 | 6.0% | 89.0% |
| 4 | 2 | 14 | 3.0% | 92.0% |
| 4 | 3 | 15 | 2.0% | 94.0% |
| 4 | 4 | 16 | 2.0% | 96.0% |
| 5 | 1 | 17 | 1.0% | 97.0% |
| 5 | 2 | 18 | 1.0% | 98.0% |
| 5 | 3 | 19 | 1.5% | 99.5% |
| 5 | 4 | 20 | 0.5% | 100.0% |



## Expenditure Pattern for EPC Capital Cost
### Supply Side Option: 1x0 MW GE LMS100PA

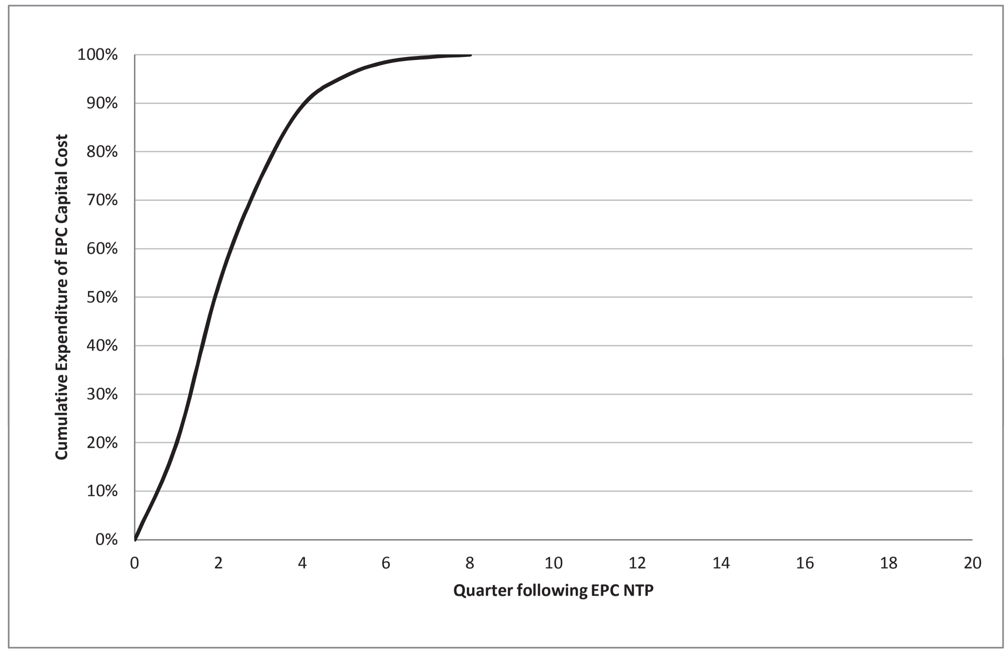
| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 19.0% | 19.0% |
| 1 | 2 | 2 | 30.5% | 49.5% |
| 1 | 3 | 3 | 22.0% | 71.5% |
| 1 | 4 | 4 | 16.0% | 87.5% |
| 2 | 1 | 5 | 7.0% | 94.5% |
| 2 | 2 | 6 | 4.0% | 98.5% |
| 2 | 3 | 7 | 1.0% | 99.5% |
| 2 | 4 | 8 | 0.5% | 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% | 100.0% |



## Expenditure Pattern for EPC Capital Cost

**Supply Side Option: 6x0 Wartsila 18V50SG**

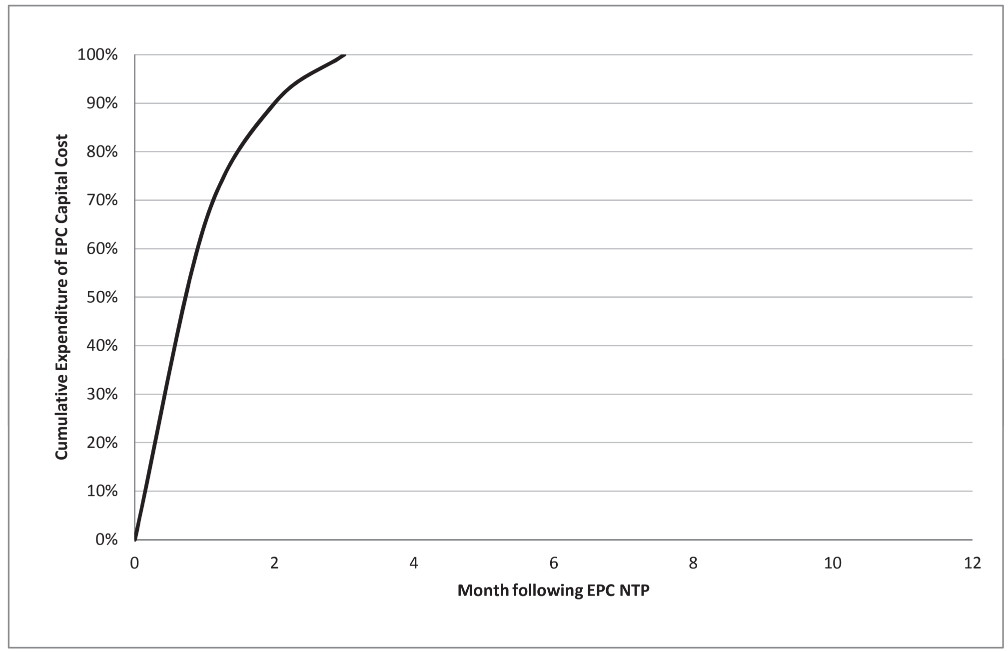
| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 20.0% | 20.0% |
| 1 | 2 | 2 | 32.5% | 52.5% |
| 1 | 3 | 3 | 22.0% | 74.5% |
| 1 | 4 | 4 | 15.0% | 89.5% |
| 2 | 1 | 5 | 6.0% | 95.5% |
| 2 | 2 | 6 | 3.0% | 98.5% |
| 2 | 3 | 7 | 1.0% | 99.5% |
| 2 | 4 | 8 | 0.5% | 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% | 100.0% |



## Expenditure Pattern for EPC Capital Cost

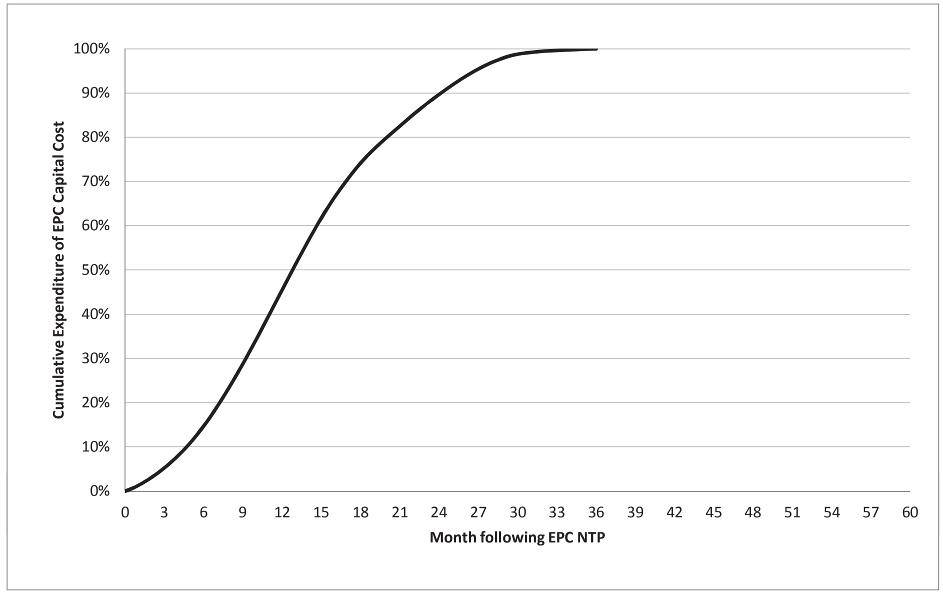
### Supply Side Option: 10 MW Solar PV

| Year | Month | Cumulative Month | Monthly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 65.0% | 65.0% |
| 1 | 2 | 2 | 25.0% | 90.0% |
| 1 | 3 | 3 | 10.0% | 100.0% |
| 1 | 4 | 4 | 0.0% | 100.0% |
| 1 | 5 | 5 | 0.0% | 100.0% |
| 1 | 6 | 6 | 0.0% | 100.0% |
| 1 | 7 | 7 | 0.0% | 100.0% |
| 1 | 8 | 8 | 0.0% | 100.0% |
| 1 | 9 | 9 | 0.0% | 100.0% |
| 1 | 10 | 10 | 0.0% | 100.0% |
| 1 | 11 | 11 | 0.0% | 100.0% |
| 1 | 12 | 12 | 0.0% | 100.0% |
| 2 | 1 | 13 | 0.0% | 100.0% |
| 2 | 2 | 14 | 0.0% | 100.0% |
| 2 | 3 | 15 | 0.0% | 100.0% |
| 2 | 4 | 16 | 0.0% | 100.0% |
| 2 | 5 | 17 | 0.0% | 100.0% |
| 2 | 6 | 18 | 0.0% | 100.0% |
| 2 | 7 | 19 | 0.0% | 100.0% |
| 2 | 8 | 20 | 0.0% | 100.0% |



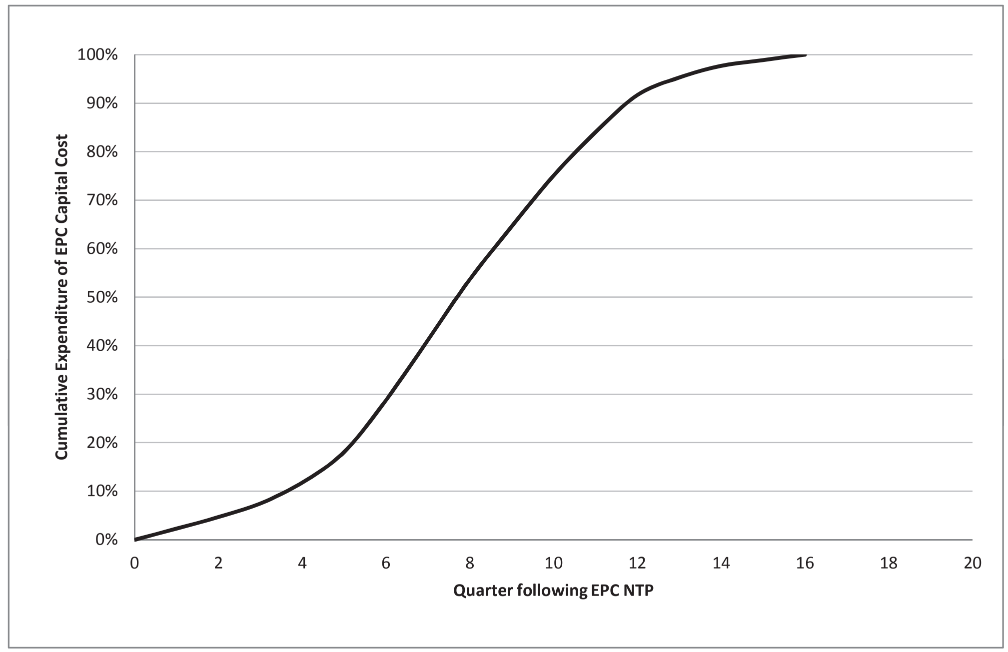
## Expenditure Pattern for EPC Capital Cost
### Supply Side Option: 25 MW Biomass Combustion (BFB)

| 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: 20 MW Geothermal**

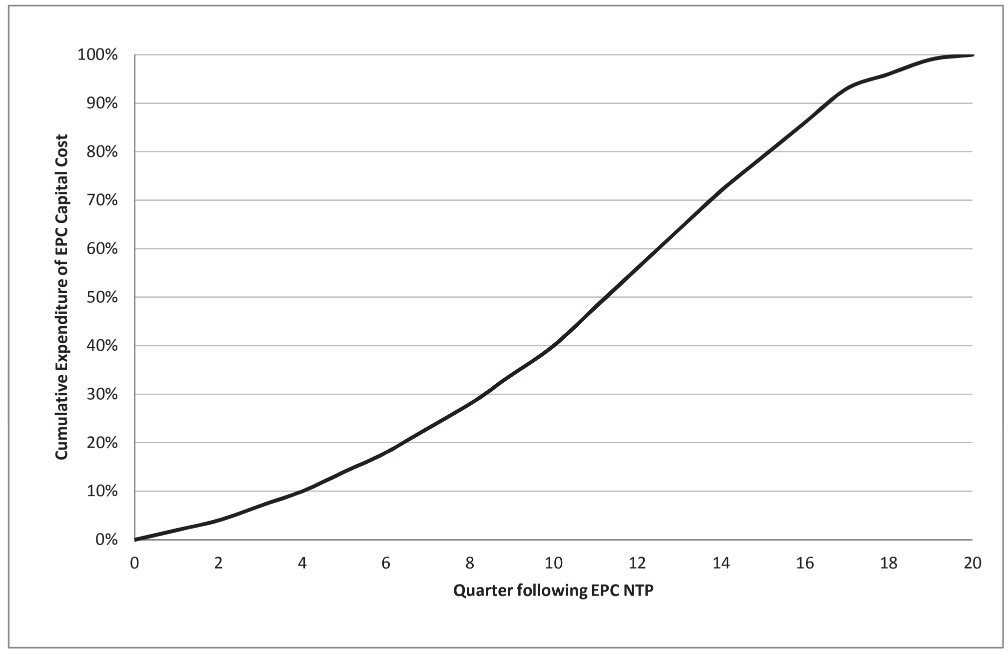
| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 2.3% | 2.3% |
| 1 | 2 | 2 | 2.4% | 4.7% |
| 1 | 3 | 3 | 2.8% | 7.5% |
| 1 | 4 | 4 | 4.3% | 11.8% |
| 2 | 1 | 5 | 6.3% | 18.1% |
| 2 | 2 | 6 | 10.7% | 28.8% |
| 2 | 3 | 7 | 12.4% | 41.2% |
| 2 | 4 | 8 | 12.5% | 53.7% |
| 3 | 1 | 9 | 10.9% | 64.6% |
| 3 | 2 | 10 | 10.5% | 75.1% |
| 3 | 3 | 11 | 8.9% | 84.0% |
| 3 | 4 | 12 | 7.7% | 91.7% |
| 4 | 1 | 13 | 3.6% | 95.3% |
| 4 | 2 | 14 | 2.4% | 97.7% |
| 4 | 3 | 15 | 1.2% | 98.9% |
| 4 | 4 | 16 | 1.1% | 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: 500 MW Pumped Storage Hydro**

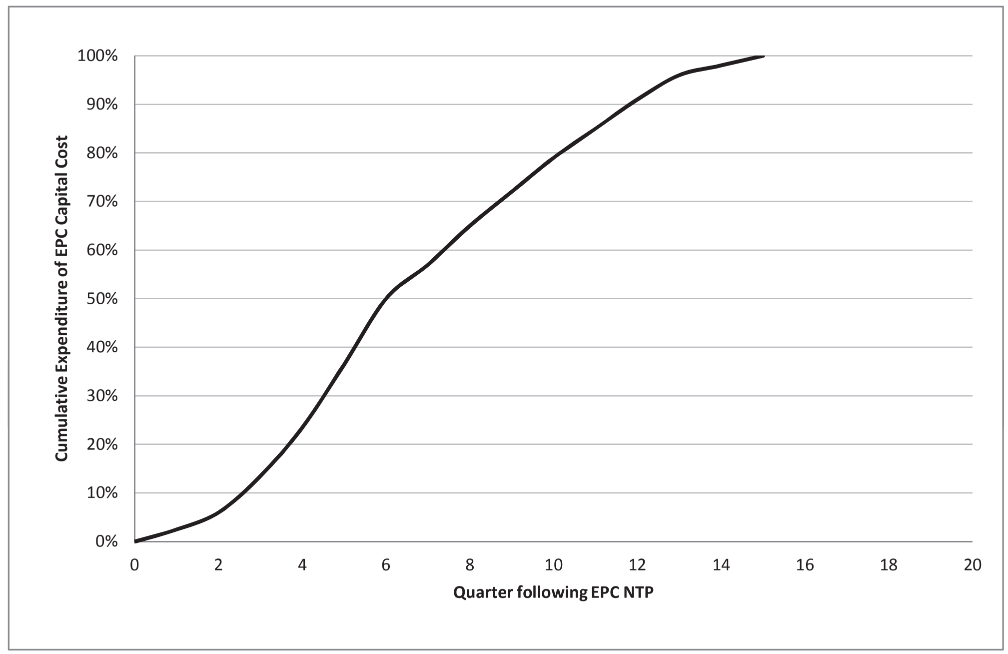
| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 2.0% | 2.0% |
| 1 | 2 | 2 | 2.0% | 4.0% |
| 1 | 3 | 3 | 3.0% | 7.0% |
| 1 | 4 | 4 | 3.0% | 10.0% |
| 2 | 1 | 5 | 4.0% | 14.0% |
| 2 | 2 | 6 | 4.0% | 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: 25 MW Li-Ion Battery Energy Storage**

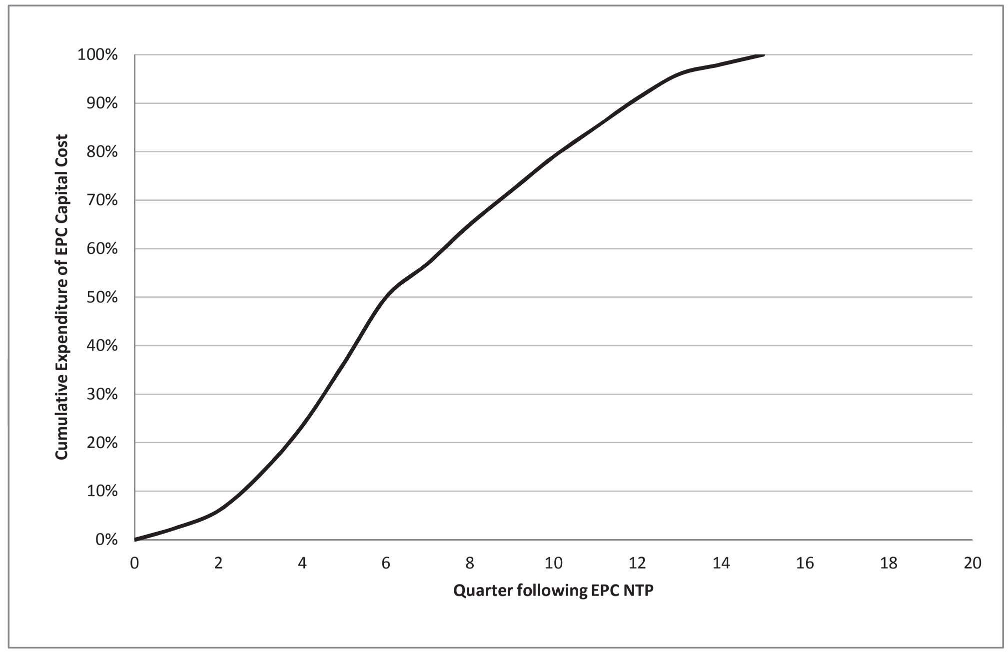
| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 2.5% | 2.5% |
| 1 | 2 | 2 | 3.5% | 6.0% |
| 1 | 3 | 3 | 7.5% | 13.5% |
| 1 | 4 | 4 | 10.0% | 23.5% |
| 2 | 1 | 5 | 13.0% | 36.5% |
| 2 | 2 | 6 | 13.5% | 50.0% |
| 2 | 3 | 7 | 7.0% | 57.0% |
| 2 | 4 | 8 | 8.0% | 65.0% |
| 3 | 1 | 9 | 7.0% | 72.0% |
| 3 | 2 | 10 | 7.0% | 79.0% |
| 3 | 3 | 11 | 6.0% | 85.0% |
| 3 | 4 | 12 | 6.0% | 91.0% |
| 4 | 1 | 13 | 5.0% | 96.0% |
| 4 | 2 | 14 | 2.0% | 98.0% |
| 4 | 3 | 15 | 2.0% | 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 Li-Ion Battery Energy Storage**

| Year | Quarter | Cumulative Quarter | Quarterly Expenditure (%) | Cumulative Expenditure (%) |
|---|---|---|---|---|
| | | 0 | 0.0% | 0.0% |
| 1 | 1 | 1 | 2.5% | 2.5% |
| 1 | 2 | 2 | 3.5% | 6.0% |
| 1 | 3 | 3 | 7.5% | 13.5% |
| 1 | 4 | 4 | 10.0% | 23.5% |
| 2 | 1 | 5 | 13.0% | 36.5% |
| 2 | 2 | 6 | 13.5% | 50.0% |
| 2 | 3 | 7 | 7.0% | 57.0% |
| 2 | 4 | 8 | 8.0% | 65.0% |
| 3 | 1 | 9 | 7.0% | 72.0% |
| 3 | 2 | 10 | 7.0% | 79.0% |
| 3 | 3 | 11 | 6.0% | 85.0% |
| 3 | 4 | 12 | 6.0% | 91.0% |
| 4 | 1 | 13 | 5.0% | 96.0% |
| 4 | 2 | 14 | 2.0% | 98.0% |
| 4 | 3 | 15 | 2.0% | 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% |



FINAL REPORT

# CHARACTERIZATION OF SUPPLY SIDE OPTIONS – WIND ENERGY

B&V PROJECT NO. 178601
B&V FILE NO. 90.0000

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PREPARED FOR

Portland General Electric

29 APRIL 2013

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# Legal Notice

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# 1.0 Introduction

Black & Veatch has prepared this update to a report issued February 22, 2013, to characterize supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs characterized in this update include:

- Wind Farm (100 MW, 80 meter hub-height, 3-bladed horizontal axis machine)
- Wind Farm (300 MW, 80 meter hub-height, 3-bladed horizontal axis machine)

Both of these technology options are considered for four representative sites in the following states:

- Montana
- Oregon
- Washington
- Wyoming

The technology options and representative sites are described in the following sections, including a brief technology overview and characterization of the performance and cost parameters of each SSO. A full matrix of cost and performance parameters for the requested SSOs is provided as Appendix A.

# 2.0 Design Basis and General Assumptions

## 2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch established design basis parameters for each of the SSOs under consideration. For each SSO, 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 (%) | PRIMARY FUEL |
|---|---|---|---|---|---|
| Wind Farm | 63 1.6 MW Wind Turbine Generators | As-Available | 100 | Varies based on site | n/a |
| Wind Farm | 188 1.6 MW Wind Turbine Generators | As-Available | 300 | Varies based on site | n/a |

## 2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, general site assumptions employed by Black & Veatch for these SSOs include the following:

- 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.
- Spread footings are assumed for all equipment foundations.
- All buildings will be pre-engineered 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.
- Costs for transmission lines and switching stations are included as part of the owner's cost estimate.

## 2.3 REPRESENTATIVE SITE DESCRIPTIONS

Each state was evaluated for likely site characteristics based on estimated wind speed, topography, proximity to existing transmission, and federal land restrictions. Representative sites were created to base production and cost estimates on realistic parameters for each state. A brief description of each representative site's physical characteristics and expected wind speed is provided below.

### 2.3.1 Oregon

A representative site in Oregon consists of flat plains (2% - 4%) and rolling hills (4% – 8% grade) along steep ridgelines (15% - 35% grade). Access would be moderately difficult along these ridgelines. Vegetation on the plains and hills is moderate, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 6.0 meters per second and 6.5 meters per second.

### 2.3.2 Montana

A representative site in Montana consists of moderate terrain with rolling hills (4% – 8% grade) sloping up gradually to a sudden drop-off along steep ridgelines (15% - 30% grade). Access is estimated to be fairly simple if approached on the side with a gradual incline. Vegetation on the hills is moderate to low, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 8.0 meters per second and 9.0 meters per second.

### 2.3.3 Washington

A representative site in Washington consists of rolling hills (4% – 8% grade) with some isolated peaks in the area. Access would be moderately difficult given the hilly surroundings. Vegetation on the plains and hills is moderate, generally consisting of grasslands or farmland. The average 80 meter wind speed in the area is between 6.5 meters per second and 7.0 meters per second.

### 2.3.4 Wyoming

A representative site in Wyoming consists of flat plateaus (1% - 4% grade) and rolling hills (4% – 8% grade) sloping up to a drop-off along fairly steep ridgelines (5% - 13% grade). Access would be relatively easy in the plateaus and hills. There are also some isolated peaks in the area. Vegetation on the plains and hills is low, consisting of grasslands. The average 80 meter wind speed in the area is between 8.5 meters per second and 9.0 meters per second.

## 2.4 CAPITAL COST ESTIMATING ASSUMPTIONS

Assumptions associated with capital cost estimates developed by Black & Veatch include the following:

- Capital cost estimates were developed on an engineer, procure, and construct (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- 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.

- A recommended allowance for Owner's costs has been provided for each technology, separately from the EPC capital cost estimates. Potential Owner's costs are listed in Table 2-2.
- All capital cost estimates are presented in 2012 dollars.

**Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects**

| | |
|---|---|
| **Project Development**<br>• Site selection study<br>• Land leasing and rezoning for greenfield sites<br>• Transmission right-of-way<br>• Road modifications/upgrades<br>• Demolition<br>• Environmental permitting/offsets<br>• Public relations/community development<br>• Legal assistance<br>• Provision of project management | **Owner's Contingency**<br>• Owner's uncertainty and costs pending final negotiation<br>• Unidentified project scope increases<br>• Unidentified project requirements<br>• Costs pending final agreements (i.e., interconnection contract costs)<br><br>**Owner's Project Management**<br>• Preparation of bid documents and the selection of contractors and suppliers<br>• Performance of engineering due diligence<br>• Provision of personnel for site construction management |
| **Spare Parts and Plant Equipment**<br>• Wind turbine generator materials, supplies, and parts<br>• Balance-of-plant equipment/tools<br>• Rolling stock<br>• Plant furnishings and supplies | **Taxes/Advisory Fees/Legal**<br>• Taxes<br>• Market and environmental consultants<br>• Owner's legal expenses<br>• Interconnect agreements<br>• Contracts (procurement and construction)<br>• Property |
| **Plant Startup/Construction Support**<br>• Owner's site mobilization<br>• O&M staff training<br>• Initial test fluids and lubricants<br>• Initial inventory of chemicals and reagents<br>• Consumables<br>• Auxiliary power purchases<br>• Acceptance testing<br>• Construction all-risk insurance | **Utility Interconnections**<br>• Natural gas service<br>• Electrical service<br>• Water supply<br><br>**Financing (included in fixed charge rate)**<br>• Financial advisor, lender's legal, market analyst, and engineer<br>• Loan administration and commitment fees<br>• Debt service reserve fund |

### 2.4.1 Direct Cost Assumptions

Assumptions regarding direct costs within the capital cost estimates include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on a turnkey EPC contracting philosophy, but with owner purchase of wind turbines.
- Permitting and licensing are excluded from EPC costs. These items should be included in the owner's cost estimate.

### 2.4.2 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.

## 2.5 OPERATION & 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, (2) market reports including summaries of wind project operating costs across the United States, and (3) relevant vendor information available to Black & Veatch.

- O&M cost estimates were reviewed, and although in all costs were considered to be Fixed O&M. Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
- O&M cost estimates are presented in 2012 dollars.

## 2.6 ADDITIONAL FINANCIAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including escalation of capital costs (over an extended term); capital expenditures and maintenance accruals; and decommissioning costs.

### 2.6.1 Escalation of Capital Costs (over an Extended Term)

Evolving technologies such as solar and wind have seen significant reductions in costs during the past two decades in spite of pressure on the EPC market for conventional resources. These market trends are difficult to accurately forecast. As such, Black & Veatch generally employs the expected general inflation rate as a proxy for long-term escalation for planning studies. While there may be periods where market pressures cause short-term fluctuations in capital costs, the general outlook of Black & Veatch regarding capital costs is (1) conventional alternatives will be steady, and (2) renewable alternatives such as wind will slow in their decreasing prices and become steady.

### 2.6.2 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). 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), 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.

### 2.6.3 Decommissioning Costs

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 the site would be returned to a Brownfield condition at the end of its book life. The fixed amount was determined using a sinking fund factor based on the book life of the asset and an assumed interest rate of 6 percent. The future amount was estimated based on a percentage of the current total capital requirement of the asset. The percentage was based on recent decommissioning cost estimates for similar scope of decommissioning for similar assets.

# 3.0 Renewable Generation Options

Renewable SSOs considered for this effort include:

- Wind Farm (100 MW, 63 80 meter hub-height, 3-bladed horizontal axis machines)
- Wind Farm (300 MW, 188 80 meter hub-height, 3-bladed horizontal axis machines)

These renewable SSOs and their performance and cost characteristics are defined below.

## 3.1 WIND FARM

### 3.1.1 Technology Overview

Wind energy technology has made major advancements since the production of wind turbines in the early 1980's. Three decades of technological progress has resulted in today's wind turbines being a cutting edge technology. A modern, single wind turbine has the ability to produce nearly two hundred times more electricity annually and at less than half the cost per kWh than its equivalent twenty years ago. The wind power sector now includes some of the world's largest energy companies.

Although wind turbines have advanced significantly in design, their basic operating principles have remained virtually unchanged. Figure 3-1 from the U.S. Department of Energy shows the typical layout of equipment in a wind turbine nacelle. Almost all of these subsystem elements have counterparts in conventional electric generation systems but differ greatly in their implementation. The prime mover in wind turbines consists of power extracted from the wind, which is converted to rotational mechanical energy by means of the aerodynamic properties of the turbine blades. This rotational energy is then transmitted to the generator rotor through a drive train. This may be by means of a gear box to a 4 or 6 pole generator, or directly to a low-speed multi-pole generator. Turbines typically rotate at between 10 and 20 RPM at rated power. In order to operate efficiently, the orientation of the wind turbine is always kept facing the oncoming wind by means of the yaw mechanism. The turbine's controller has autonomous control of most all of its functions including the operation of various switches, hydraulic pumps, valves, and motors. The control system operates within various parameters and will commence simple or even emergency procedures in response to pre-programmed settings.

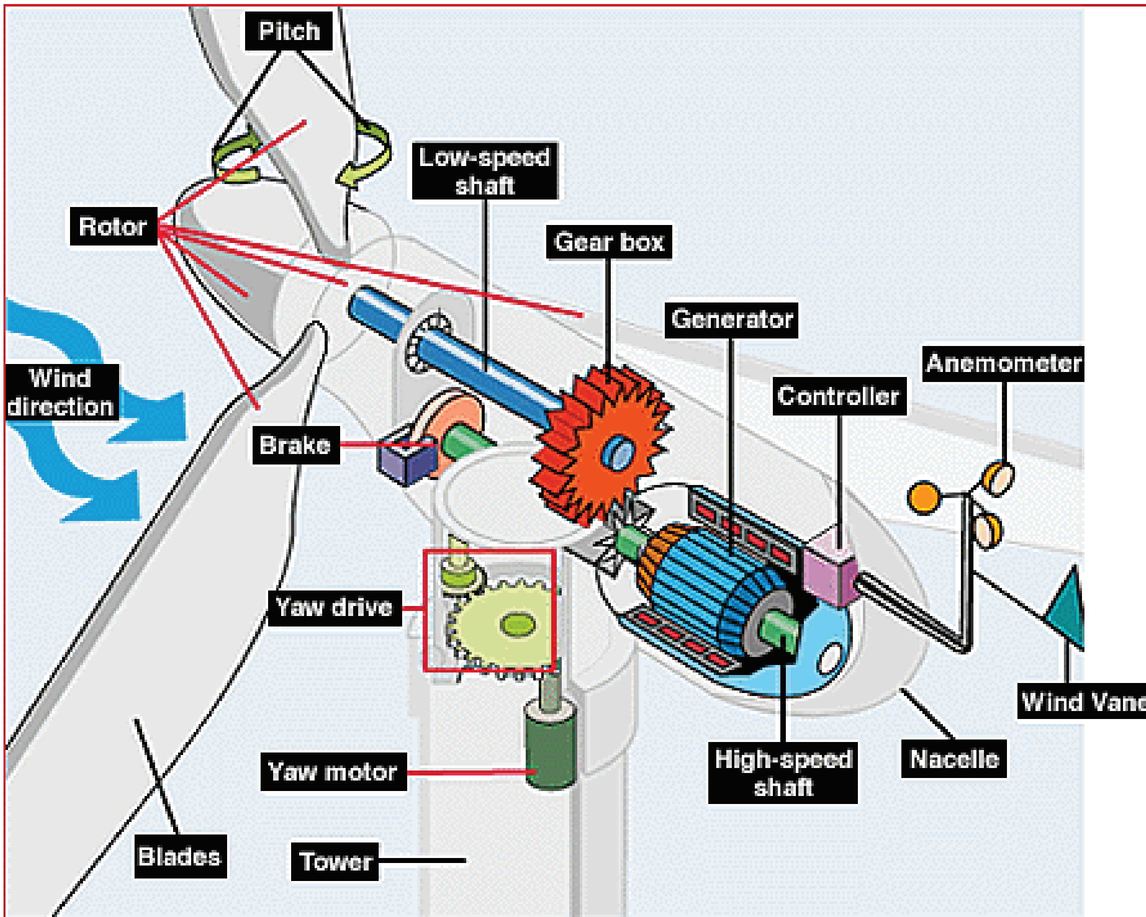



**Figure 3-1 Wind Turbine Components**

The technology employed in large commercial wind turbines for electromechanical energy conversion deviates somewhat from conventional generation equipment. In lieu of synchronous generators, induction machines are used in most commercial-scale wind turbine designs, typically connected to the grid via sophisticated power electronics that alter the fundamental behavior of the induction machines in both steady-state and dynamic operation. Others use synchronous designs with permanent magnet excitation, but are connected to the grid through a rectifier and power converter. In response to the advancing demands for power quality, remote data acquisition, and fault response capabilities, turbine manufacturers are implementing higher reliability systems to accommodate these explicit grid connection requirements.

### 3.1.2 Wind Farm Configuration

A wind farm typically consists of many individual wind turbines spread across a large area. The overall shape and size of a wind farm varies with each individual project, but they are typically arranged in several rows or cluster of turbines. Wind resource, terrain, land cover, land ownership, residences, environmental restrictions, and existing road networks all influence the final configuration of a wind project. Although a large amount of land is required for development and construction of a wind project, most of the land is undisturbed by the project and can remain in use for its original purpose. This makes large wind projects highly compatible with agricultural activities, with some exceptions such as aerial application of pesticides and fertilizers.

Wind turbines generally are mounted to relatively shallow octagonal inverted tee spread footing foundations, typically between 50 and 60 feet across, with anchor bolts embedded into a smaller circular pedestal 10-15 feet across, to which the turbine tower is mounted. Depending on the specific configuration of the wind turbine generators, a small transformer may be mounted adjacent to the turbine base, inside the base of the turbine tower, or in the turbine nacelle. This transformer converts power from the typical 600 V generating voltage to the 35 kV class collection system voltage (typically 34.5 kV in the US).

Permanent gravel access roads are generally built to each individual wind turbine location. For a project developed in open ranch land or on rolling hills a network of new access roads is often built from turbine to turbine. The roads may follow existing roads with improvements and modifications, or may be entirely new build. For a project developed in relatively flat cultivated farmland with a gridded road network individual turbine access roads may be short straight roads connected to the public roads rather than a turbine to turbine network.

A central collection substation is generally built within the overall footprint of a wind farm. This collection substation includes the main power transformer, which converts the collection system voltage to the voltage of the interconnection transmission line. From this collection substation wind farm is interconnected to the grid. The interconnection point may be adjacent to the substation if it is built along the interconnecting transmission line, or the project may construct a new transmission line and interconnection switchyard adjacent to the interconnecting transmission line. Each turbine is connected electrically into groups of 8-15, and power is brought back to the collection substation. The collection lines may follow access road routes, or may be trenched directly from turbine to turbine. Often collection lines follow the access road routes when a new wind farm specific access road network is built, and are trenched directly from turbine to turbine when the access roads connect back to a gridded public road network.

Although each turbine is fully capable of autonomous operation, all turbines are linked together to a project control system (SCADA). The central SCADA system can monitor and control the project as needed, included recording of all project operating data and implementation of curtailment controls as needed.

In addition to the turbines, access roads, collection system, and substation, wind projects typically include an operations and maintenance (O&M) facility. This facility is often a pre-engineered building and warehouse, with offices, conference rooms, restrooms and showers, storage, and warehousing.

### 3.1.3 Wind Resource and Energy Generation

To calculate the expected energy output of a wind farm the most important input is the wind resource. Wind resource information for this update is from estimates developed for the U.S. Department of Energy by AWS Truepower, LLC. Using a high-resolution grid, 80 meter annual average wind speeds were mapped for the United States. The model used a spatial resolution of 2.5 km that was interpolated to a finer scale.

Wind speeds are presented in the AWS map as ranges. For this update, average annual 80 meter wind speeds for each site were selected based on the mid-point of each range. Using the mid-point wind speeds, the sites were assumed to be Class III or Class II locations. A common machine for Class III sites is the GE 1.6-100, and for Class II sites the GE 1.6-82.5 is often utilized. These two machines were chosen because they are seen in sites throughout the United States similar to the ones under consideration in this update, and because these two turbines are based on the same technologies and design platforms. The power curves for both machines were adjusted to account for the impact of the site air density. Air density was estimated based on annual temperatures for each state collected from representative airport data and pressure derived from site elevation and a hub-height of 80 meters. The wind speed ranges, wind speeds chosen for each site, assumed class, chosen turbine, and air density for the site are shown in Table 3-1 below.

**Table 3-1 Estimated 80 meter annual average wind speeds**

| STATE OF SITE | WIND SPEED RANGE | MID-POINT | WTG CLASS | CHOSEN WTG | AIR DENSITY |
|---|---|---|---|---|---|
| Oregon | 6.0 m/s – 6.5 m/s | 6.25 m/s | Class III | GE 1.6-100 | 1.14 |
| Montana | 8.0 m/s – 9.0 m/s | 8.5 m/s | Class II | GE 1.6-82.5 | 1.11 |
| Washington | 6.5 m/s – 7.0 m/s | 6.75 m/s | Class III | GE 1.6-100 | 1.12 |
| Wyoming | 8.5 m/s – 9.0 m/s | 8.75 m/s | Class II | GE 1.6-82.5 | 1.02 |

### 3.1.4 Technology-Specific Assumptions

Cost and performance have been developed for a two utility-scale wind farm scenarios. The utility-scale wind farms are assumed to have nameplate capacities of roughly 100 MW and 300 MW, composed of 63 1.6 MW machines and 188 1.6 MW machines, respectively. Relevant assumptions employed in the development of performance and cost parameters for these two utility-scale wind farms include the following:

- Wind turbines would be spaced sufficiently to prevent significant wake losses caused by neighboring turbines. A common distance is ten rotor diameters in the direction of the predominant wind direction, and four rotor diameters in the direction perpendicular to the predominant wind direction.
- The site does not have unusually turbulent flows or other environmental conditions that might impact the functionality or cause damage to the wind turbines.

- A Weibull curve fit based upon the mean wind speed with a standard Raleigh distribution is assumed to accurately represent the wind characteristics of each site.
- The model included typical losses due to wakes, availability, environmental impacts, electrical losses, maintenance and other sources of loss. Losses were assumed to be greater for the 300 MW case, as more rows would probably be needed to fit 188 turbines on a given site. This would result in higher wake losses due to deep array effects, which have been accounted for in Table 3-3.

Table 3-2 Project Losses for 100 MW cases

| LOSS ESTIMATE | LOSS | FACTOR |
|---|---|---|
| Topographic | 1% | 99% |
| Wake | 6% | 94% |
| Availability | 4% | 96% |
| Power Curve | 2% | 98% |
| Grid | 1% | 99% |
| Electrical | 2% | 98% |
| Columnar | 0% | 100% |
| Contamination | 1% | 99% |
| Icing | 2% | 98% |
| Model | 1% | 99% |
| Hysteresis | 0% | 100% |
| Total | 18.75% | 81% |

Table 3-3 Project Losses for 300 MW cases

| LOSS ESTIMATE | LOSS | FACTOR |
|---|---|---|
| Topographic | 1% | 99% |
| Wake | 10% | 90% |
| Availability | 4% | 96% |
| Power Curve | 2% | 98% |
| Grid | 1% | 99% |
| Electrical | 2% | 98% |
| Columnar | 0% | 100% |
| Contamination | 1% | 99% |
| Icing | 2% | 98% |
| Model | 1% | 99% |
| Hysteresis | 0% | 100% |

| | | |
|---|---|---|
| Total | 22.20% | 78% |

- The EPC costs model assumed the main characteristics listed below:
  - There is minimal vegetation to be removed.
  - Both the GE 1.6-100 and the GE 1.6-82.5 are installed using the 80 meter hub-height configuration and have the same costs for BOP/erection, but different costs by turbine.
  - The BOP costs are assumed to be the same regardless of turbine type, but will be impacted by the average site slope. The impact of site slope are accounted for by applying the multipliers shown in Table 3-4 to BOP/erection costs and switchyard costs:

Table 3-4 Slope multipliers to BOP/erection costs and switchyard

| SLOPE | MULTIPLIER |
|---|---|
| Slope < 4% | 1.00 |
| 4% < slope < 8% | 1.16 |
| 8% < slope < 16% | 1.22 |
| slope > 16% | 1.55 |

  - BOP costs will also be impacted slightly by the difficulty of approach to a site. A gradually increasing slope with existing roads will be easier to access than a region with abrupt changes in grade and no existing roads. Table 3-5 shows the additional multipliers applied to the BOP costs based on ease of access.

Table 3-5 Ease of access multipliers to BOP/erection costs

| EASE OF ACCESS | MULTIPLIER |
|---|---|
| Simple | 1.00 |
| Moderate | 1.04 |
| Difficult | 1.08 |

  - Owner's costs are assumed to be 10% of direct costs and Finance costs are assumed to be 5% of direct costs, shown as Owner's Cost Allowance in Table 3-7.
- The installation is assumed to be performed by an experienced contractor. An experienced contractor provides:
  - Efficient design and construction processes.
  - Most economical equipment pricing from vendors.

- The AC collector station is next to the point of interconnection.

## 3.2 TECHNICAL AND FINANCIAL PARAMETERS FOR RENEWABLE GENERATION OPTIONS

Technical parameters for renewable energy options considered for PGE are summarized in Table 3-6, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 3-7 and Table 3-8.

**Table 3-6 Technical Parameters for Renewable Generation Options**

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | LAND REQUIRED (ACRES) (1) | HEAT RATE (BTW/ kWh) | MINIMUM TURNDOWN CAPACITY (%)(2) | RAMP RATE (MW/MIN) | WATER CONSUMPTION (MGD) (3) | SCHEDULED MAINTENANCE PATTERN (WEEKS/YR) (4) | EQUIVALENT FORCED OUTAGE RATE (%) |
|---|---|---|---|---|---|---|---|---|---|
| Oregon Site Wind Farm | 100 | 31 | 24,900 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Oregon Site Wind Farm | 300 | 30 | 73,510 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Montana Site Wind Farm | 100 | 41 | 16,950 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Montana Site Wind Farm | 300 | 39 | 50,030 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Washington Site Wind Farm | 100 | 35 | 24,900 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Washington Site Wind Farm | 300 | 34 | 73,510 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Wyoming Site Wind Farm | 100 | 41 | 16,950 | N/A | N/A | N/A | 0.0 | N/A | N/A |
| Wyoming Site Wind Farm | 300 | 39 | 50,030 | N/A | N/A | N/A | 0.0 | N/A | N/A |

(1) For the 100 MW case it is assumed that the 63 turbines spaced at 4 x 10 diameters and are arranged in 3 rows. For the 300 MW case it is assumed that the 188 turbines spaced at 4 x 10 diameters and are arranged in 6 rows. Class III and Class II sites have rotor diameters of 100 meters and 82.5 meters, respectively.

(2) If it is necessary to curtail wind power output, the inverter is capable of curtailing 100% of the power output.

(3) For Wind, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other industrial water consumption required for operation of wind facility.

(4) Maintenance is performed on a continuous, rolling schedule throughout the year. Each individual turbine will be offline for roughly 100 hours during maintenance, but the entire farm will not be offline at any point during the maintenance cycle, except for 1-2 days when substation maintenance is performed.

**Table 3-7 Financial Parameters for Renewable Generation Options**

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | BOOK LIFE (YEARS) | EPC PROJECT DURATION[1] (MONTHS) | EXPENDITURE PATTERN | OVERNIGHT EPC CAPITAL COST ($000, 2012$) | OWNER'S COST ALLOWANCE (%) | OVERNIGHT TOTAL CAPITAL COST ($000, 2012$) |
|---|---|---|---|---|---|---|---|---|
| Oregon Site Wind Farm | 100 | 31 | 25 | 12 | See Appendix B | 209,100 | 15 | 240,470 |
| Oregon Site Wind Farm | 300 | 30 | 25 | 12 | See Appendix B | 627,300 | 15 | 721,400 |
| Montana Site Wind Farm | 100 | 41 | 25 | 12 | See Appendix B | 191,920 | 15 | 220,710 |
| Montana Site Wind Farm | 300 | 39 | 25 | 12 | See Appendix B | 575,760 | 15 | 662,120 |
| Washington Site Wind Farm | 100 | 35 | 25 | 12 | See Appendix B | 209,100 | 15 | 240,470 |
| Washington Site Wind Farm | 300 | 34 | 25 | 12 | See Appendix B | 627,300 | 15 | 721,400 |
| Wyoming Site Wind Farm | 100 | 41 | 25 | 12 | See Appendix B | 182,000 | 15 | 209,300 |
| Wyoming Site Wind Farm | 300 | 39 | 25 | 12 | See Appendix B | 546,000 | 15 | 627,900 |

(1) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).

**Table 3-8 Financial Parameters for Renewable Generation Options – Continued**

| SUPPLY-SIDE OPTION | NET CAPACITY (MW) | CAPACITY FACTOR (%) | FIXED O&M COST ($/kW-YEAR) | NON-FUEL VARIABLE O&M COST ($/MWh) | DECOMISSIONING ACCRUAL[1] ($000, 2012$) | LONG-TERM CAPITAL COST ESCALATION RATE[2] |
|---|---|---|---|---|---|---|
| Oregon Site Wind Farm | 100 | 31 | 40 | 0.0 | 1,240 | General Inflation |
| Oregon Site Wind Farm | 300 | 30 | 40 | 0.0 | 3,713 | General Inflation |
| Montana Site Wind Farm | 100 | 41 | 40 | 0.0 | 1,240 | General Inflation |
| Montana Site Wind Farm | 300 | 39 | 40 | 0.0 | 3,713 | General Inflation |
| Washington Site Wind Farm | 100 | 35 | 40 | 0.0 | 1,240 | General Inflation |
| Washington Site Wind Farm | 300 | 34 | 40 | 0.0 | 3,713 | General Inflation |
| Wyoming Site Wind Farm | 100 | 41 | 40 | 0.0 | 1,240 | General Inflation |
| Wyoming Site Wind Farm | 300 | 39 | 40 | 0.0 | 3,713 | General Inflation |

(1) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition. Estimate is a net cost offset by the salvage of each turbine.

(2) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

# Appendix A. Supply Side Option Parameters (Full Table)

| No. | Option | Option Design Basis | Duty | Net Capacity (MW) | Capacity Factor (%) | Primary Fuel | Land Required (acres)[1] | Net Plant Heat Rate (Btu/kWh) | Minimum Turndown Capacity (%)[2] | Range of Potential NPHR Improvements (%) | Ramp Rate (MW/min) | Water Consumption (mgd)[3] | Scheduled Maint. Pattern (weeks/yr)[4] | Equiv. Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Design Basis Parameters | | | | | Technical/Performance Parameters | | | | | | | |
| 1 | Oregon Site Wind Farm | 63 1.6 MW Wind Turbine Generators | As-Available | 100 | 31 | N/A | 24,900 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 2 | Oregon Site Wind Farm | 188 1.6 MW Wind Turbine Generators | As-Available | 300 | 30 | N/A | 73,510 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 3 | Montana Site Wind Farm | 63 1.6 MW Wind Turbine Generators | As-Available | 100 | 41 | N/A | 16,950 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 4 | Montana Site Wind Farm | 188 1.6 MW Wind Turbine Generators | As-Available | 300 | 39 | N/A | 50,030 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 5 | Washington Site Wind Farm | 63 1.6 MW Wind Turbine Generators | As-Available | 100 | 35 | N/A | 24,900 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 6 | Washington Site Wind Farm | 188 1.6 MW Wind Turbine Generators | As-Available | 300 | 34 | N/A | 73,510 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 7 | Wyoming Site Wind Farm | 63 1.6 MW Wind Turbine Generators | As-Available | 100 | 41 | N/A | 16,950 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |
| 8 | Wyoming Site Wind Farm | 188 1.6 MW Wind Turbine Generators | As-Available | 300 | 39 | N/A | 50,030 | N/A | N/A | N/A | N/A | 0 | N/A | N/A |

NOTES:

(1) For the 100 MW case it is assumed that the 63 turbines spaced at 4 x 10 diameters and are arranged in 3 rows. For the 300 MW case it is assumed that the 188 turbines spaced at 4 x 10 diameters and are arranged in 6 rows. Class III and Class II sites have rotor diameters of 100 meters and 82.5 meters, respectively.
(2) If it is necessary to curtail wind power output, the inverter is capable of curtailing 100% of the power output.
(3) For Wind, it is assumed that rainfall will be sufficient to make panel washing unnecessary. No other water consumption required for operation of wind facility.
(4) Maintenance is performed on a continuous, rolling schedule throughout the year. Each individual turbine will be offline for roughly 100 hours during maintenance, but the entire farm will not be offline at any point during the maintenance cycle, except for 1-2 days when substation maintenance is performed.
(5) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD).
(6) Accrual collected annually over the book life of the asset to decommission the facility and return the site to a Brownfield condition. Estimate is a net cost offset by the salvage of each turbine.
(7) For utility planning studies, Black & Veatch typically employs the expected general inflation rate as a proxy for long-term escalation.

| | | Financial Parameters | | | | | | | | | | | Energy Storage Parameters | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Option | Book Life (years) | EPC Period[5] (months) | Expenditure Pattern (by month/qtr) | Overnight EPC Capital Cost ($000, 2012$) | Owner's Cost Allowance (%) | Overnight Total Capital Cost ($000, 2012$) | Fixed O&M Cost ($/kW-year) | Variable O&M Cost ($/MWh) | Capital Additions/ Maint. Accrual ($/yr) | Decom-missioning Accrual[6] ($000/yr) | Capital Cost Escalation Rate[7] | Energy Capacity (MWh) | Discharge Period (hours) | Round Trip Efficiency (%) | Cycle Life -- for Battery Options (cycles) |
| 1 | Oregon Site Wind Farm | 25 | 12 | See Appendix B | 209,100 | 15 | 240,470 | 40 | 0 | N/A | 1,240 | General Inflation | N/A | N/A | N/A | N/A |
| 2 | Oregon Site Wind Farm | 25 | 12 | See Appendix B | 627,300 | 15 | 721,400 | 40 | 0 | N/A | 3,713 | General Inflation | N/A | N/A | N/A | N/A |
| 3 | Montana Site Wind Farm | 25 | 12 | See Appendix B | 191,920 | 15 | 220,710 | 40 | 0 | N/A | 1,240 | General Inflation | N/A | N/A | N/A | N/A |
| 4 | Montana Site Wind Farm | 25 | 12 | See Appendix B | 575,760 | 15 | 662,120 | 40 | 0 | N/A | 3,713 | General Inflation | N/A | N/A | N/A | N/A |
| 5 | Washington Site Wind Farm | 25 | 12 | See Appendix B | 209,100 | 15 | 240,470 | 40 | 0 | N/A | 1,240 | General Inflation | N/A | N/A | N/A | N/A |
| 6 | Washington Site Wind Farm | 25 | 12 | See Appendix B | 627,300 | 15 | 721,400 | 40 | 0 | N/A | 3,713 | General Inflation | N/A | N/A | N/A | N/A |
| 7 | Wyoming Site Wind Farm | 25 | 12 | See Appendix B | 182,000 | 15 | 209,300 | 40 | 0 | N/A | 1,240 | General Inflation | N/A | N/A | N/A | N/A |
| 8 | Wyoming Site Wind Farm | 25 | 12 | See Appendix B | 546,000 | 15 | 627,900 | 40 | 0 | N/A | 3,713 | General Inflation | N/A | N/A | N/A | N/A |

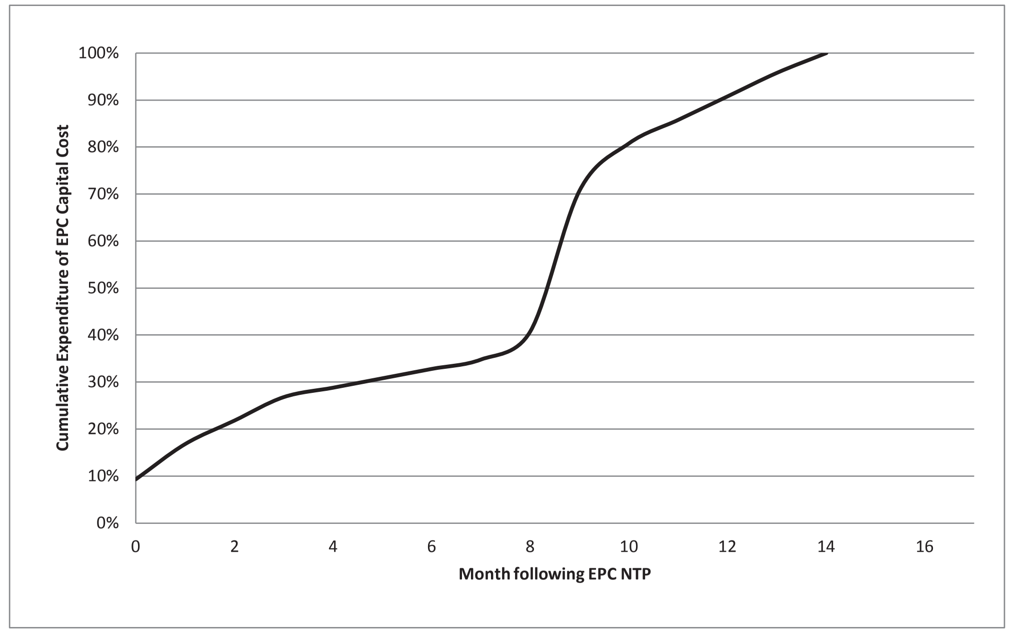
# Appendix B. SSO Expenditure Patterns

## Expenditure Pattern for EPC Capital Cost

### Supply Side Option: 100 MW & 300 MW Wind Farms

| Year | Month | Cumulative Month | Monthly Expenditure (%) | Cumulative Expenditure (%) [1] |
|---|---|---|---|---|
| | | 0 | 0.0% | 9.3% |
| 1 | 1 | 1 | 7.5% | 16.8% |
| 1 | 2 | 2 | 5.0% | 21.8% |
| 1 | 3 | 3 | 5.0% | 26.8% |
| 1 | 4 | 4 | 2.0% | 28.8% |
| 1 | 5 | 5 | 2.0% | 30.8% |
| 1 | 6 | 6 | 2.0% | 32.8% |
| 1 | 7 | 7 | 2.0% | 34.8% |
| 1 | 8 | 8 | 6.0% | 40.8% |
| 1 | 9 | 9 | 30.0% | 70.8% |
| 1 | 10 | 10 | 10.0% | 80.8% |
| 1 | 11 | 11 | 5.0% | 85.8% |
| 1 | 12 | 12 | 5.0% | 90.8% |
| 2 | 1 | 13 | 5.0% | 95.8% |
| 2 | 2 | 14 | 4.2% | 100.0% |

[1] Expenditures prior to EPC NTP account for roughly 9% of the total Capitol Costs



# COST REPORT

# COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

FEBRUARY 2012

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Building a world of difference.®

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# Table of Contents

# 1 Introduction

Black & Veatch contracted with the National Renewable Energy Laboratory (NREL) in 2009 to provide the power generating technology cost and performance estimates that are described in this report. These data were synthesized from various sources in late 2009 and early 2010 and therefore reflect the environment and thinking at that time or somewhat earlier, and not of the present day.

Many factors drive the cost and price of a given technology. Mature technologies generally have a smaller band of uncertainty around their costs because demand/supply is more stable and technology variations are fewer. For mature plants, the primary uncertainty is associated with the owner-defined scope that is required to implement the technology and with the site-specific variable costs. These are site-specific items (such as labor rates, indoor versus outdoor plant, water supply, access roads, labor camps, permitting and licensing, or lay-down areas) and owner-specific items (such as sales taxes, financing costs, or legal costs). Mature power plant costs are generally expected to follow the overall general inflation rate over the long term.

Over the last ten years, there has been doubling in the nominal cost of all power generation technologies and an even steeper increase in coal and nuclear because the price of commodities such as iron, steel, concrete, copper, nickel, zinc, and aluminum have risen at a rate much greater than general inflation; construction costs peak in 2009 for all types of new power plants. Even the cost of engineers and constructors has increased faster than general inflation has. With the recent economic recession, there has been a decrease in commodity costs; some degree of leveling off is expected as the United States completes economic recovery.

It is not possible to reasonably forecast whether future commodity prices will increase, decrease, or remain the same. Although the costs in 2009 are much higher than earlier in the decade, for modeling purposes, the costs presented here do not anticipate dramatic increases or decreases in basic commodity prices through 2050. Cost trajectories were assumed to be based on technology maturity levels and expected performance improvements due to learning, normal evolutionary development, deployment incentives, etc.

Black & Veatch does not encourage universal use solely of learning curve effects, which give a cost reduction with each doubling in implementation dependent on an assumed deployment policy. Many factors influence rates of deployment and the resulting cost reduction, and in contrast to learning curves, a linear improvement was modeled to the extent possible.

## 1.1 ASSUMPTIONS

The cost estimates presented in this report are based on the following set of common of assumptions:

1. Unless otherwise noted in the text, costs are presented in 2009 dollars.
2. Unless otherwise noted in the text, the estimates were based on on-site construction in the Midwestern United States.
3. Plants were assumed to be constructed on “greenfield” sites. The sites were assumed to be reasonably level and clear, with no hazardous materials, no standing timber, no wetlands, and no endangered species.
4. Budgetary quotations were not requested for this activity. Values from the Black &Veatch proprietary database of estimate templates were used.
5. The concept screening level cost estimates were developed based on experience and estimating factors. The estimates reflect an overnight, turnkey Engineering Procurement Construction, direct-hire, open/merit shop, contracting philosophy.

6. Demolition of any existing structures was not included in the cost estimates.
7. Site selection was assumed to be such that foundations would require cast-in-place concrete piers at elevations to be determined during detailed design. All excavations were assumed to be "rippable" rock or soils (i.e., no blasting was assumed to be required). Piling was assumed under major equipment.
8. The estimates were based on using granular backfill materials from nearby borrow areas.
9. The design of the HVAC and cooling water systems and freeze protection systems reflected a site location in a relatively cold climate. With the exception of geothermal and solar, the plants were designed as indoor plants.
10. The sites were assumed to have sufficient area available to accommodate construction activities including but not limited to construction offices, warehouses, lay-down and staging areas, field fabrication areas, and concrete batch plant facilities, if required.
11. Procurements were assumed to not be constrained by any owner sourcing restrictions, i.e., global sourcing. Manufacturers' standard products were assumed to be used to the greatest extent possible.
12. Gas plants were assumed to be single fuel only. Natural gas was assumed to be available at the plant fence at the required pressure and volume as a pipeline connection. Coal plants were fueled with a Midwestern bituminous coal.
13. Water was assumed to be available at the plant fence with a pipeline connection.
14. The estimates included an administration/control building.
15. The estimates were based on 2009 costs; therefore, escalation was not included.
16. Direct estimated costs included the purchase of major equipment, balance-of-plant (BOP) equipment and materials, erection labor, and all contractor services for "furnish and erect" subcontract items.
17. Spare parts for start-up and commissioning were included in the owner's costs.
18. Construction person-hours were based on a 50-hour workweek using merit/open shop craftspersons.
19. The composite crew labor rate was for the Midwestern states. Rates included payroll and payroll taxes and benefits.
20. Project management, engineering, procurement, quality control, and related services were included in the engineering services.
21. Field construction management services included field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control. Also included was technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services.
22. Engineering, procurement, and construction (EPC) contractor contingency and profit allowances were included with the installation costs.
23. Construction management cost estimates were based on a percentage of craft labor person-hours. Construction utilities and start-up utilities such as water, power, and fuel were to be provided by the owner. On-site construction distribution infrastructures for these utilities were included in the estimate.
24. Owner's costs were included as a separate line item.
25. Operational spare parts were included as an owner's cost.
26. Project insurances, including "Builders All-Risk" insurance, were included in the estimates as an owner's cost.
27. Construction permits were assumed to be owner's costs.

28. The estimates included any property, sales or use taxes, gross receipt tax, import or export duties, excise or local taxes, license fees, value added tax, or other similar taxes in the owner's costs.
29. Costs to upgrade roads, bridges, railroads, and other infrastructure outside the site boundary, for equipment transportation to the facility site, were included in the owner's costs.
30. Costs of land, and all right-of-way access, were provided in the owner's Costs.
31. All permitting and licensing were included in the owner's costs.
32. All costs were based on scope ending at the step-up transformer. The electric switchyard, transmission tap-line, and interconnection were excluded.
33. Similarly, the interest during construction (IDC) was excluded.
34. Other owner's costs were included.

In some cases, a blended average technology configuration was used as the proxy for a range of possible technologies in a given category. For example, a number of concentrating solar power technologies may be commercialized over the next 40 years. Black & Veatch used trough technology for the early trajectory and tower technology for the later part of the trajectory. The costs were meant to represent the expected cost of a range of possible technology solutions. Similarly, many marine hydrokinetic options may be commercialized over the next 40 years. No single technology offering is modeled.

For technologies such as enhanced geothermal, deep offshore wind, or marine hydrokinetic where the technology has not been fully demonstrated and commercialized, estimates were based on Nth plant costs. The date of first implementation was assumed to be after at least three full-scale plants have successfully operated for 3–5 years. The first Nth plants were therefore modeled at a future time beyond 2010. For these new and currently non-commercial technologies, demonstration plant cost premiums and early financial premiums were excluded. In particular, although costs are in 2009 dollars, several technologies are not currently in construction and could not be online in 2010.

The cost data presented in this report provide a future trajectory predicted primarily from historical pricing data as influenced by existing levels of government and private research, development, demonstration, and deployment incentives.

Black & Veatch estimated costs for fully demonstrated technologies were based on experience obtained in EPC projects, engineering studies, owner's engineer and due diligence work, and evaluation of power purchase agreement (PPA) pricing. Costs for other technologies or advanced versions of demonstrated technologies were based on engineering studies and other published sources. A more complete discussion of the cost estimating data and methodologies follows.

## 1.2 ESTIMATION OF DATA AND METHODOLOGY

The best estimates available to Black & Veatch were EPC estimates from projects for which Black & Veatch performed construction or construction management services. Second best were projects for which Black & Veatch was the owner's engineer for the project owner. These estimates provided an understanding of the detailed direct and indirect costs for equipment, materials and labor, and the relationship between each of these costs at a level of detail requiring little contingency. These detailed construction estimates also allowed an understanding of the owner's costs and their impact on the overall estimate. Black & Veatch tracks the detailed estimates and often uses these to perform studies and develop estimates for projects defined at lower levels of detail. Black & Veatch is able to stay current with market conditions through due diligence work it does for financial institutions and others and when it reviews energy prices for new PPAs. Finally, Black & Veatch also prepares proposals for projects of a similar nature. Current market insight is used to adjust detailed estimates as required to keep them up-to-date. Thus, it is an important part of the company's business model to stay current with costs for all types of projects. Project costs for site-specific engineering studies and for more generic engineering studies are frequently adjusted by adding, or subtracting, specific scope items associated with a particular site location. Thus, Black & Veatch has an understanding of the range of costs that might be expected for particular technology applications. (See Text Box 1 for a discussion of cost uncertainty bands.)

Black & Veatch is able to augment its data and to interpret it using published third-party sources; Black & Veatch is also able to understand published sources and apply judgment in interpreting third-party cost reports and estimates in order to understand the marketplace. Reported costs often differ from Black & Veatch's experience, but Black & Veatch is able to infer possible reasons depending upon the source and detail of the cost data. Black & Veatch also uses its cost data and understanding of that data to prepare models and tools.

Though future technology costs are highly uncertain, the experiences and expertise described above enable Black & Veatch to make reasonable cost and performance projections for a wide array of generation technologies. Though technology costs can vary regionally, cost data presented in this report are in strong agreement with other technology cost estimates (FERC 2008, Kelton et al. 2009, Lazard 2009). This report describes the projected cost data and performance data for electric generation technologies.

### Text Box 1. Why Estimates Are Not Single Points

In a recent utility solicitation for (engineering, procurement and construction) EPC and power purchase agreement (PPA) bids for the same wind project at a specific site, the bids varied by 60%. More typically, when bidders propose on the exact scope at the same location for the same client, their bids vary by on the order of 10% or more. Why does this variability occur and what does it mean? Different bidders make different assumptions, they often obtain bids from multiple equipment suppliers, different construction contractors, they have different overheads, different profit requirements and they have better or worse capabilities to estimate and perform the work. These factors can all show up as a range of bids to accomplish the same scope for the same client in the same location.

Proposing for different clients generally results in increased variability. Utilities, Private Power Producers, State or Federal entities, all can have different requirements that impact costs. Sparing requirements, assumptions used for economic tradeoffs, a client's sales tax status, or financial and economic assumptions, equipment warranty requirements, or plant performance guarantees inform bid costs. Bidders' contracting philosophy can also introduce variability. Some will contract lump sum fixed price and some will contract using cost plus. Some will use many contractors and consultants; some will want a single source. Some manage with in-house resources and account for those resources; some use all external resources. This variation alone can impact costs still another 10% or more because it impacts the visibility of costs, the allocation of risks and profit margins, and the extent to which profits might occur at several different places in the project structure.

Change the site and variability increases still further. Different locations can have differing requirements for use of union or non-union labor. Overall productivity and labor cost vary in different regions. Sales tax rates vary, local market conditions vary, and even profit margins and perceived risk can vary.

Site-specific scope is also an issue. Access roads, laydown areas,[1] transportation distances to the site and availability of utilities, indoor vs. outdoor buildings, ambient temperatures and many other site-specific issues can affect scope and specific equipment needs and choices.

Owners will also have specific needs and their costs will vary for a cost category referred to as Owner's costs. The Electric Power Research Institute (EPRI) standard owner's costs include 1) paid-up royalty allowance, 2) preproduction costs, 3) inventory capital and 4) land costs. However, this total construction cost or total capital requirement by EPRI does not include many of the other owner's costs that a contractor like Black & Veatch would include in project cost comparisons. These additional elements include the following:

- **Spare parts and plant equipment** includes materials, supplies and parts, machine shop equipment, rolling stock, plant furnishings and supplies.
- **Utility interconnections** include natural gas service, gas system upgrades, electrical transmission, substation/switchyard, wastewater and supply water or wells and railroad.
- **Project development** includes fuel-related project management and engineering, site selection, preliminary engineering, land and rezoning, rights of way for pipelines, laydown yard, access roads, demolition, environmental permitting and offsets, public relations, community development, site development legal assistance, man-camp, heliport, barge unloading facility, airstrip and diesel fuel storage.
- **Owner's project management** includes bid document preparation, owner's project management, engineering due diligence and owner's site construction management.

[1] A laydown yard or area is an area where equipment to be installed is temporarily stored.

- **Taxes/ins/advisory fees/legal** includes sales/use and property tax, market and environmental consultants and rating agencies, owner's legal expenses, PPA, interconnect agreements, contract-procurement and construction, property transfer/title/escrow and construction all risk insurance.

- **Financing** includes financial advisor, market analyst and engineer, loan administration and commitment fees and debt service reserve fund.

- **Plant startup/construction support** includes owner's site mobilization, operation and maintenance (O&M) staff training and pre-commercial operation, start-up, initial test fluids, initial inventory of chemical and reagents, major consumables and cost of fuel not covered recovered in power sales.

Some overlap can be seen in the categories above, which is another contributor to variability - different estimators prepare estimates using different formats and methodologies.

Another form of variability that exists in estimates concerns the use of different classes of estimate and associated types of contingency. There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site-specific differences.

Given all these sources of variability, contractors normally speak in terms of cost ranges and not specific values. Modelers, on the other hand, often find it easier to deal with single point estimates. While modelers often conveniently think of one price, competition can result in many price/cost options. It is not possible to estimate costs with as much precision as many think it is possible to do; further, the idea of a national average cost that can be applied universally is actually problematic. One can calculate a historical national average cost for anything, but predicting a future national average cost with some certainty for a developing technology and geographically diverse markets that are evolving is far from straightforward.

**Implications**

Because cost estimates reflect these sources of variability, they are best thought of as ranges that reflect the variability as well as other uncertainties. When the cost estimate ranges for two technologies overlap, either technology could be the most cost effective solution for any given specific owner and site. Of course, capital costs may not reflect the entire value proposition of a technology, and other cost components, like O&M or fuel costs with their own sources of variability and uncertainty, might be necessary to include in a cost analysis.

For models, we often simplify calculations by using points instead of ranges that reflect variability and uncertainty, so that we can more easily address other important complexities such as the cost of transmission or system integration. However, we must remember that when actual decisions are made, decision makers will include implicit or explicit consideration of capital cost uncertainty when assessing technology trade-offs. This is why two adjacent utilities with seemingly similar needs may procure two completely different technology solutions. Economic optimization models generally cannot be relied on as the final basis for site-specific decisions. One of the reasons is estimate uncertainty. A relatively minor change in cost can result in a change in technology selection. Because of unknowns at particular site and customer specific situations, it is unlikely that all customers would switch to a specific technology solution at the same time. Therefore, modelers should ensure that model algorithms or input criteria do not allow major shifts in technology choice for small differences in technology cost. In addition, generic estimates should not be used in site- specific user-specific analyses.

# 2 Cost Estimates and Performance Data for Conventional Electricity Technologies

This section includes description and tabular data on the cost and performance projections for "conventional" non-renewable technologies, which include fossil technologies (natural gas combustion turbine, natural gas combined-cycle, and pulverized coal) with and without carbon capture and storage, and nuclear technologies. In addition, costs for flue gas desulfurization2 (FGD) retrofits are also described.

## 2.1 NUCLEAR POWER TECHNOLOGY

Black & Veatch's nuclear experience spans the full range of nuclear engineering services, including EPC, modification services, design and consulting services and research support. Black & Veatch is currently working under service agreement arrangements with MHI for both generic and plant specific designs of the United States Advanced Pressurized Water Reactor (US-APWR). Black & Veatch historical data and recent market data were used to make adjustments to study estimates to include owner's costs. The nuclear plant proxy was based on a commercial Westinghouse AP1000 reactor design producing 1,125 net MW. The capital cost in 2010 was estimated at 6,100$/kW +30%. We anticipate that advanced designs could be commercialized in the United States under government-sponsored programs. While we do not anticipate cost savings associated with these advanced designs, we assumed a cost reduction of 10% for potential improved metallurgy for piping and vessels. Table 1 presents cost and performance data for nuclear power. Figure 1 shows the 2010 cost breakdown for a nuclear power plant.

[2] Flue gas desulfurization (FGD) technology is also referred to as $SO_2$ scrubber technology.

**Table 1. Cost and Performance Projection for a Nuclear Power Plant (1125 MW)**

| Year | Capital Cost ($/kW) | Fixed O&M[a] ($/kW-yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR[b] (%) | FOR[c] (%) | Min. Load (%) | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 6,230 | – | – | – | – | – | – | 5.00 | 5.00 |
| 2010 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2015 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2020 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2025 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2030 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2035 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2040 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2045 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |
| 2050 | 6,100 | 127 | 9,720 | 60 | 6.00 | 4.00 | 50 | 5.00 | 5.00 |

[a] O&M = operation and maintenance
[b] POR = planned outage rate
[c] FOR = forced outage rate

All costs in 2009$

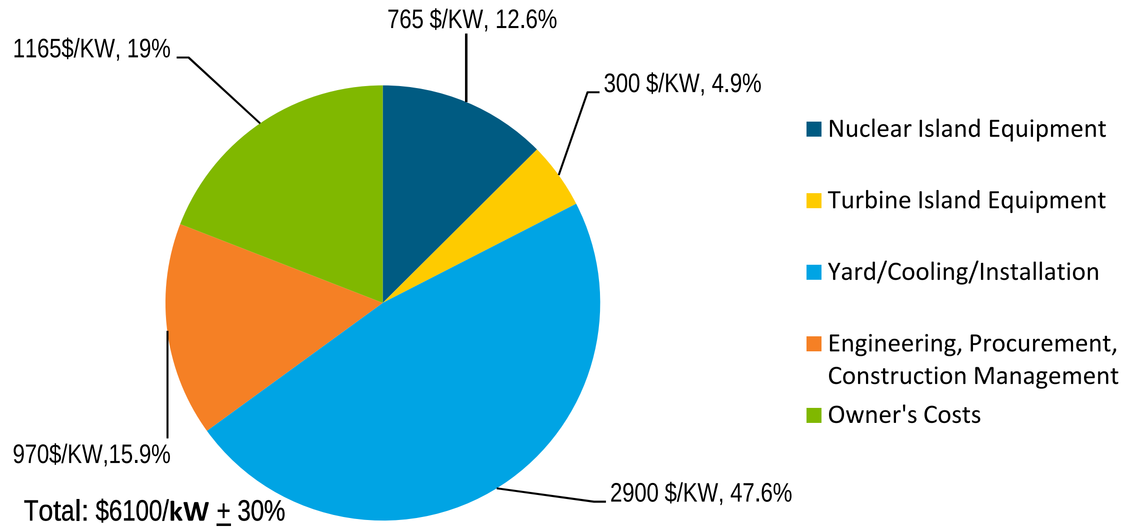


**Figure 1. Capital cost breakdown for a nuclear power plant**

The total plant labor and installation is included in the Yard/Cooling/ Installation cost element. The power plant is assumed to be a single unit with no provision for future additions. Switchyard, interconnection and interest during construction are not included. Owner's costs are defined in Text Box 1 above.

## 2.2 COMBUSTION TURBINE TECHNOLOGY

Natural gas combustion turbine costs were based on a typical industrial heavy-duty gas turbine, GE Frame 7FA or equivalent of the 211-net-MW size. The estimate did not include the cost of selective catalytic reduction (SCR)/carbon monoxide (CO) reactor for NOx and CO reduction. The combustion turbine generator was assumed to include a dry, low NOx combustion system capable of realizing 9 parts per million by volume, dry (ppmvd) @ 15% O2 at full load. A 2010 capital cost was estimated at 651 $/kW ±25%. Cost uncertainty for this technology is low. Although it is possible that advanced configurations will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades (Shelley 2008). Cost estimates did not include any cost or performance improvements through 2050. Table 2 presents cost and performance data for gas turbine technology. Table 3 presents emission rates for the technology. Figure 2 shows the 2010 capital cost breakdown by component for a natural gas combustion turbine plant.

**Table 2. Cost and Performance Projection for a Gas Turbine Power Plant (211 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Min. Load (%) | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 671 | – | – | – | – | – | – | – | – | – |
| 2010 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2015 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2020 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2025 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2030 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2035 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2040 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2045 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |
| 2050 | 651 | 29.9 | 5.26 | 10,390 | 30 | 5.00 | 3.00 | 50 | 8.33 | 22.20 |

**Table 3. Emission Rates for a Gas Turbine Power Plant**

| $SO_2$ (Lb/mmbtu) | NOx (Lb/mmbtu) | PM10 (Lb/mmbtu) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|
| 0.0002 | 0.033 | 0.006 | 117 |

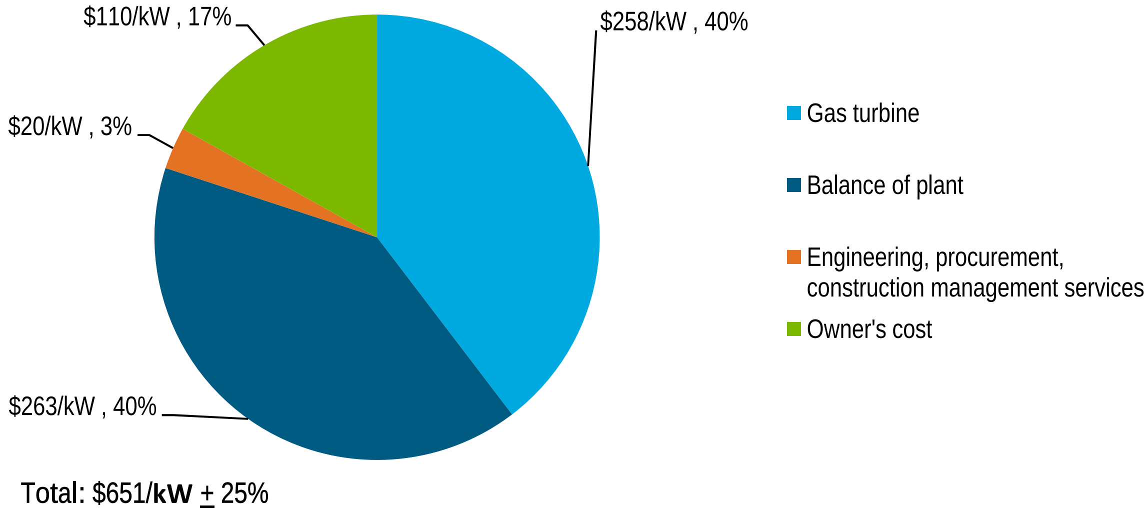


**Figure 2. Capital cost breakdown for a gas turbine power plant**

## 2.3 COMBINED-CYCLE TECHNOLOGY

Natural gas combined-cycle (CC) technology was represented by a 615- MW plant. Costs were based on two GE 7FA combustion turbines or equivalent, two heat recovery steam generators (HRSGs), a single reheat steam turbine and a wet mechanical draft cooling tower. The cost included a SCR/CO reactor housed within the HRSGs for NOx and CO reduction. The combustion turbine generator was assumed to include dry low NOx combustion system capable of realizing 9 ppmvd @ 15% $O_2$ at full load.

2010 capital cost was estimated to be 1,230 $/kW +25%. Cost uncertainty for CC technology is low. Although it is possible that advanced configurations for CC components will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades. The cost estimates did not include any cost reduction through 2050. Table 4 presents cost and performance data for combined-cycle technology. Table 5 presents emission data for the technology. The 2010 capital cost breakdown for the combined-cycle power plant is shown in Figure 3.

**Table 4. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Min. Load (%) | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 1250 | – | – | – | – | – | – | – | – | – |
| 2010 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2015 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2020 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2025 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2030 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2035 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2040 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2045 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2050 | 1230 | 3.67 | 6.31 | 6,705 | 41 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |

**Table 5. Emission Rates for a Combined-Cycle Power Plant**

| $SO_2$ (Lb/mmbtu) | $NO_X$ (LB/mmbtu) | PM10 (Lb/mmbtu) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|
| 0.0002 | 0.0073 | 0.0058 | 117 |

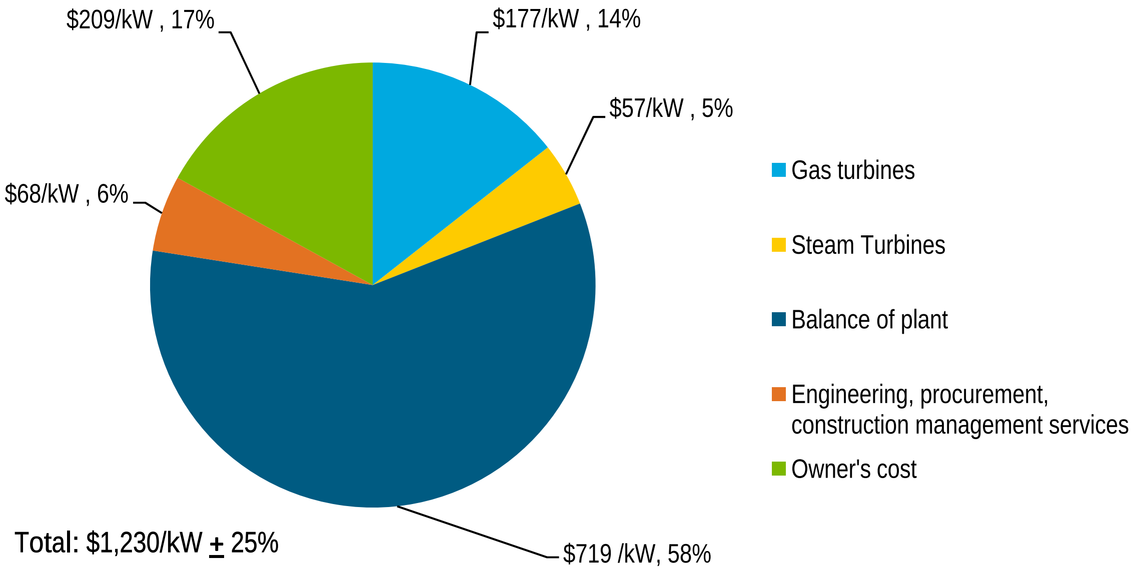


**Figure 3. Capital cost breakdown for a combined-cycle power plant**

## 2.4 COMBINED-CYCLE WITH CARBON CAPTURE AND SEQUESTRATION

Carbon capture and sequestration (CCS) was added to the above CC. Black & Veatch has no EPC estimates for CCS since it is not commercial at this time. However, Black & Veatch has participated in engineering and cost studies of CCS and has some understanding of the range of expected costs for CO2 storage in different geologic conditions. The CC costs were based on two combustion turbines, a single steam turbine and wet cooling tower producing 580 net MW after taking into consideration CCS. This is the same combined cycle described above but with CCS added to achieve 85% capture. CCS is assumed to be commercially available after 2020. 2020 capital cost was estimated at 3,750$/kW +35%. Cost uncertainty is higher than for the CC without CCS due to the uncertainty associated with the CCS system. Although it is possible that advanced CC configurations will be developed over the next 40 years, the economic incentive for new gas turbine CC development has not been apparent in the last decade. Further, while cost improvements in CCS may be developed over time, it is expected that geologic conditions will become more difficult as initial easier sites are used. The cost of perpetual storage insurance was not estimated or included. Table 4 presents cost and performance data for combined-cycle with carbon capture and sequestration technology. Table 5 presents emission data for the technology.

**Table 6. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW) with Carbon Capture and Sequestration**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/kWh) | Const. Schedule (Months) | POR (%) | FOR (%) | Min Load (% | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 3860 | – | – | – | – | – | – | – | – | – |
| 2010 | – | – | – | – | – | – | – | – | – | – |
| 2015 | – | – | – | – | – | – | – | – | – | – |
| 2020 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2025 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2030 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2035 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2040 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2045 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |
| 2050 | 3750 | 10 | 18.4 | 10,080 | 44 | 6.00 | 4.00 | 50 | 5.00 | 2.50 |

**Table 7. Emission Rates for a Combined-Cycle Power Plant with Carbon Capture and Sequestration**

| $SO_2$ (Lb/mmbtu) | NOx (LB/mmbtu) | PM10 (Lb/mmbtu) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|
| 0.0002 | 0.0073 | 0.0058 | 18 |

## 2.5 PULVERIZED COAL-FIRED POWER GENERATION

Pulverized coal-fired power plant costs were based on a single reheat, condensing, tandem-compound, four-flow steam turbine generator set, a single reheat supercritical steam generator and wet mechanical draft cooling tower, a SCR, and air quality control equipment for particulate and SO2 control, all designed as typical of recent U.S. installations. The estimate included the cost of a SCR reactor. The steam generator was assumed to include low NOx burners and other features to control NOx. Net output was approximately 606 MW.

2010 capital cost was estimated at 2,890 $/kW +35%. Cost certainty for this technology is relatively high. Over the 40-year analysis period, a 4% improvement in heat rate was assumed. Table 8 presents cost and performance data for pulverized coal-fired technology.

Table 9 presents emissions rates for the technology. The 2010 capital cost breakdown for the pulverized coal-fired power plant is shown in Figure 4.

**Table 8. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (606 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Min Load (%) | Spin Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 3040 | – | – | – | – | – | – | – | – |
| 2010 | 2890 | 3.71 | 23.0 | 9,370 | 55 | 10 | 6 | 40 | 2.00 |
| 2015 | 2890 | 3.71 | 23.0 | 9,370 | 55 | 10 | 6 | 40 | 2.00 |
| 2020 | 2890 | 3.71 | 23.0 | 9,370 | 55 | 10 | 6 | 40 | 2.00 |
| 2025 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |
| 2030 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |
| 2035 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |
| 2040 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |
| 2045 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |
| 2050 | 2890 | 3.71 | 23.0 | 9,000 | 55 | 10 | 6 | 40 | 2.00 |

**Table 9. Emission Rates for a Pulverized Coal-Fired Power Plant**

| $SO_2$ (Lb/mmbtu) | $NO_x$ (Lb/mmbtu) | PM10 (Lb/mmbtu) | Hg (% removal) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|---|
| 0.055 | 0.05 | 0.011 | 90 | 215 |

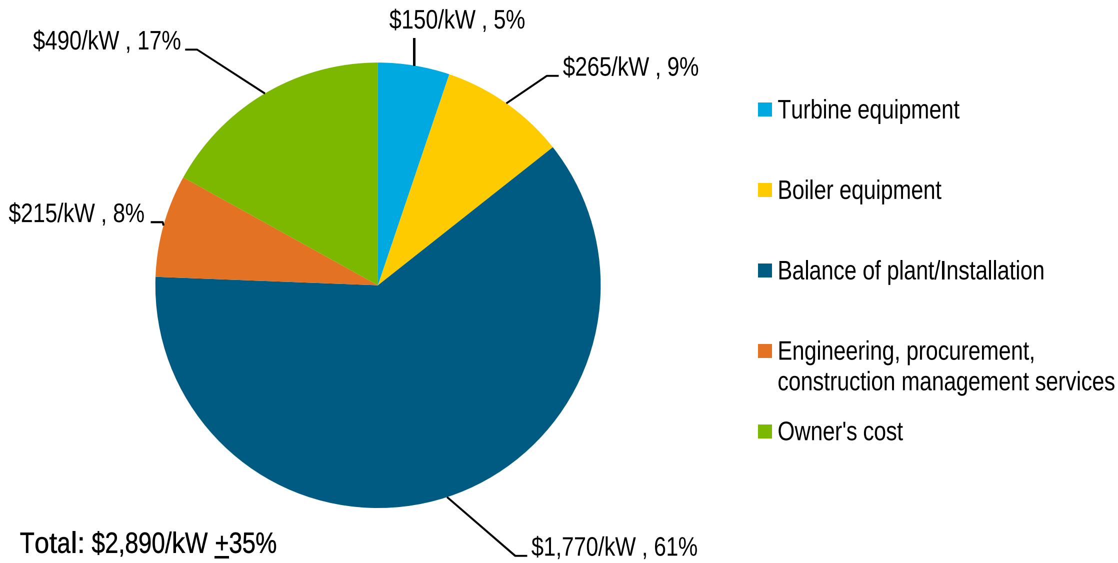


**Figure 4. Capital cost breakdown for a pulverized coal-fired power plant**

## 2.6 PULVERIZED COAL-FIRED POWER GENERATION WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes 10,000 MW of supercritical pulverized coal-fired power plant projects.

The pulverized coal-fired power plant costs were based on a supercritical steam cycle and wet cooling tower design typical of recent U.S. installations, the same plant described above but with CCS. Net output was approximately 455 MW. CCS would be based on 85% CO2 removal. CCS was assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,560$/kW -45% and +35%. Cost uncertainty is higher than for the pulverized coal-fired plant only due to the uncertainty associated with the CCS.

We assumed a 4% improvement in heat rate to account for technology potential already existing but not frequently used in the United States. The cost of perpetual storage insurance was not estimated or included. Table 8 presents cost and performance data for pulverized coal-fired with carbon capture and sequestration technology.

Table 911 presents emissions rates for the technology.

**Table 10. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (455 MW) with Carbon Capture and Sequestration**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Min Load (%) | Spin Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 6890 | – | – | – | – | – | – | – | – |
| 2010 | – | – | – | – | – | – | – | – | 2.00 |
| 2015 | – | – | – | – | – | – | – | – | 2.00 |
| 2020 | 6560 | 6.02 | 35.2 | 12,600 | 66 | 10 | 6 | 40 | 2.00 |
| 2025 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |
| 2030 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |
| 2035 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |
| 2040 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |
| 2045 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |
| 2050 | 5640 | 6.02 | 35.2 | 12,100 | 66 | 10 | 6 | 40 | 2.00 |

**Table 11. Emission Rates for a Pulverized Coal-Fired Power Plant with Carbon Capture and Sequestration**

| $SO_2$ (Lb/mmbtu) | $NO_x$ (Lb/mmbtu) | PM10 (Lb/mmbtu) | Hg (% removal) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|---|
| 0.055 | 0.05 | 0.011 | 90 | 32 |

## 2.7 GASIFICATION COMBINED-CYCLE TECHNOLOGY

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and gasification combined-cycle (GCC) projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. Special care was taken to adjust to 2009 dollars based on market experience. The GCC estimate was based on a commercial gasification process integrated with a conventional combined cycle and wet cooling tower producing 590 net MW. 2010 capital cost was estimated at 4,010$/kW-+35%.. Cost certainty for this technology is relatively high. We assumed a 12% improvement in heat rate by 2025. Table 812 presents cost and performance data for gasification combined-cycle technology.

Table 913 presents emissions rates for the technology. The Black & Veatch GCC estimate is consistent with the FERC estimate range.

**Table 12. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (590 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/kWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Min Load (%) | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 4210 | – | – | – | – | – | – | – | – | – |
| 2010 | 4010 | 6.54 | 31.1 | 9,030 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2015 | 4010 | 6.54 | 31.1 | 9,030 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2020 | 4010 | 6.54 | 31.1 | 9,030 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2025 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2030 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2035 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2040 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2045 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |
| 2050 | 4010 | 6.54 | 31.1 | 7,950 | 57 | 12 | 8 | 50 | 5 | 2.50 |

**Table 13. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant**

| $SO_2$ (Lb/mmbtu) | $NO_x$ (Lb/mmbtu) | PM10 (Lb/mmbtu) | Mercury (% Removal) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|---|
| 0.065 | 0.085 | 0.009 | 90 | 215 |

## 2.8 GASIFICATION COMBINED-CYCLE TECHNOLOGY WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and IGCC projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. The GCC was based on a commercial gasification process integrated with a conventional CC and wet cooling tower, the same plant as described above but with CCS. Net capacity was 520 MW. Carbon capture, sequestration, and storage were based on 85% carbon removal. Carbon capture and storage is assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,600 $/kW +35%. The cost of perpetual storage insurance was not estimated or included. Table 814 presents cost and performance data for gasification combined-cycle technology integrated with carbon capture and sequestration.

Table 915 presents emissions rates for the technology.

**Table 14. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (520 MW) with Carbon Capture and Sequestration**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/KWh) | Construction Schedule (Months) | FOR (%) | POR (%) | Min Load (%) | Spin Ramp Rate (%/min) | Quick Start Ramp Rate (%/min) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 6,930 | – | – | – | – | – | – | – | 5.00 | 2.50 |
| 2010 | – | – | – | – | – | – | – | – | 5.00 | 2.50 |
| 2015 | – | – | – | – | – | – | – | – | – | – |
| 2020 | 6,600 | 10.6 | 44.4 | 11,800 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2025 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2030 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2035 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2040 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2045 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |
| 2050 | 6,600 | 10.6 | 44.4 | 10,380 | 59 | 12.0 | 8.00 | 50 | 5.00 | 2.50 |

**Table 15. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant with Carbon Capture and Sequestration**

| $SO_2$ (Lb/mmbtu) | NOx (Lb/mmbtu) | PM10 (Lb/mmbtu) | Hg (% Removal) | $CO_2$ (Lb/mmbtu) |
|---|---|---|---|---|
| 0.065 | 0.085 | 0.009 | 90% | 32 |

## 2.9 FLUE GAS DESULFURIZATION RETROFIT TECHNOLOGY

Flue gas desulfurization (FGD) retrofit was assumed to be a commercial design to achieve 95% removal of sulfur dioxide and equipment was added to meet current mercury and particulate standards. A wet limestone FGD system, a fabric filter, and a powdered activated carbon (PAC) injection system were included. It is also assumed that the existing stack was not designed for a wet FGD system; therefore, a new stack was included. Black & Veatch estimated retrofit capital cost in 2010 to be 360 $/kW +25% with no cost reduction assumed through 2050. Table 16 presents costs and a construction schedule for flue gas desulfurization retrofit technology.

**Table 16. Cost and Schedule for a Power Plant (606 MW) with Flue Gas Desulfurization Retrofit Technology**

| Year | Retrofit Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) |
|---|---|---|---|---|
| 2008 | 371 | – | – | – |
| 2010 | 360 | 3.71 | 23.2 | 36 |
| 2015 | 360 | 3.71 | 23.2 | 36 |
| 2020 | 360 | 3.71 | 23.2 | 36 |
| 2025 | 360 | 3.71 | 23.2 | 36 |
| 2030 | 360 | 3.71 | 23.2 | 36 |
| 2035 | 360 | 3.71 | 23.2 | 36 |
| 2040 | 360 | 3.71 | 23.2 | 36 |
| 2045 | 360 | 3.71 | 23.2 | 36 |
| 2050 | 360 | 3.71 | 23.2 | 36 |

### Text Box 2. Cycling Considerations

- Cycling increases failures and maintenance cost.
- Power plants of the future will need increased flexibility and increased efficiency; these qualities run counter to each other.
- Higher temperatures required for increased efficiency mean slower ramp rates and less ability to operate off-design. Similarly, environmental features such as bag houses, SCR, gas turbine NOx control, FGD, and carbon capture make it more difficult to operate at off-design conditions.
- Early less-efficient power plants without modern environmental emissions controls probably have more ability to cycle than newer more highly-tuned designs.
- Peak temperature and rate of change of temperature are key limitations for cycling. Water chemistry is an issue.
- The number of discrete pulverizers is a limitation for pulverized coal power plants and the number of modules in add-on systems that must be integrated to achieve environmental control is a limitation.

<u>The ramp rate for coal plants is not linear as it is a function of bringing pulverizers on line as load increases.</u> A 600-MW pulverized coal-fired unit (e.g., Powder River Basin) can have six pulverizers. Assuming an N+1 sparing philosophy, five pulverizers are required for full load so each pulverizer can provide fuel for about 20% of full load.

From minimum stable load at about 40% to full load, it is the judgment of Black & Veatch, based on actual experience in coal plant operations, that the ramp rate will be 5 MW/minute at high loads. This is about 1%/minute for a unit when at 500 MW.

<u>The ramp rate for a combined-cycle plant is a combination of combustion turbine ramp rate and steam turbine ramp rate.</u> The conventional warm start will take about 76 minutes from start initiation to full load on the combined cycle. The combined ramp rate from minute 62 to minute 76 is shown by GE to be about 5%/minute for a warm conventional start-up.

GE shows that the total duration of a "rapid response" combined-cycle start-up assuming a combustion turbine fast start is 54 minutes as compared to a conventional start duration of 76 minutes for a warm start. The ramp rate is shown by GE to be slower during a rapid start-up. The overall duration is shorter but the high load combined ramp rate is 2.5%.

After the unit has been online and up to temperature, we would expect the ramp rate to be 5%.

# 3 Cost Estimates and Performance Data for Renewable Electricity Technologies

This section includes cost and performance data for renewable energy technologies, including biopower (biomass cofiring and standalone), geothermal (hydrothermal and enhanced geothermal systems), hydropower, ocean energy technologies (wave and tidal), solar energy technologies (photovoltaics and concentrating solar power), and wind energy technologies (onshore and offshore).

## 3.1 BIOPOWER TECHNOLOGIES

### 3.1.1 Biomass Cofiring

From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. Black & Veatch has exceptional tools to evaluate the impacts of biomass cofiring on the existing facility, such as the VISTA™ model, which evaluates impacts to the coal fueled boiler and balance of plant systems due to changes in fuels.

Although the maximum injection of biomass depends on boiler type and the number and types of necessary modifications to the boiler, biomass cofiring was assumed to be limited to a maximum of 15% for all coal plants. For the biomass cofiring retrofit, Black & Veatch estimated 2010 capital costs of 990 $/kW -50% and +25%. Cost uncertainty is significantly impacted by the degree of modifications needed for a particular fuel and boiler combination. Significantly less boiler modification may be necessary in some cases. Black & Veatch did not estimate any cost improvement over time. Table 17 presents cofiring cost and performance data. In the present convention, the capital cost to retrofit a coal plant to cofire biomass is applied to the biomass portion only3. Similarly, O&M costs are applied to the new retrofitted capacity only. Table 17 shows representative heat rates; the performance characteristics of a retrofitted plant were assumed to be the same as that of the previously existing coal plant. Many variations are possible but were not modeled. Table 18 shows the range of costs using various co-firing approaches over a range of co-firing fuel levels varying from 5% to 30%. Emissions control equipment performance limitations may limit the overall range of cofiring possible.

[3] For example, retrofitting a 100 MW coal plant to cofire up to 15% biomass has a cost of 100 MW x 15% x $990,000/MW = $14,850,000.

**Table 17. Cost and Performance Projection for Biomass Cofiring Technology**

| Year | Capital Cost ($/kW) | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/kW-Yr) | Heat Rate (Btu/KWh) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|---|
| 2008 | 1,020 | – | – | – | – | – | – |
| 2010 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2015 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2020 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2025 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2030 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2035 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2040 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2045 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |
| 2050 | 990 | 0 | 20 | 10,000 | 12 | 9 | 7 |

**Table 18. Costs for Co-Firing Methods versus Fuel Amount**

| Co-firing Level (%) | Fuel Blending ($/kW) | Separate Injection ($/kW) | Gasification ($/kW) |
|---|---|---|---|
| 5 | 1000-1500 | 1300-1800 | 2500-3500 |
| 10 | 800-1200 | 1000-1500 | 2000-2500 |
| 20 | 600 | 700-1100 | 1800-2300 |
| 30 | – | 700-1100 | 1700-2200 |

### 3.1.2 Biomass Standalone

Black & Veatch is recognized as one of the most diverse providers of biomass (solid biomass, biogas, and waste-to-energy) systems and services. From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. This background was used to develop the cost estimates vetted in the Western Renewable Energy Zone (WREZ) stakeholder process and to subsequently update that pricing and adjust owner's costs.

A standard Rankine cycle with wet mechanical draft cooling tower producing 50 MW net is initially assumed for the standalone biomass generator.4 Black & Veatch assumed the 2010 capital cost to be 3,830 $/kW -25% and +50%. Cost certainty is high for this mature technology, but there are more high cost than low cost outliers due to unique fuels and technology solutions. For modeling purposes, it was assumed that gasification combined-cycle systems displace the direct combustion systems gradually resulting in an average system heat rate that improves by 14% through 2050. However, additional cost is likely required initially to achieve this heat rate improvement and therefore no improvement in cost was assumed for the costs. Table 19 presents cost and performance data for a standalone biomass power plant. The capital cost breakdown for the biomass standalone power plant is shown in Figure 5.

[4] "Standalone" biomass generators are also referred to as "dedicated" plants to distinguish them from co-fired plants.

**Table 19. Cost and Performance Projection for a Stand-Alone Biomass Power Plant (50 MW Net)**

| Year | Capital Cost $/kW | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/kW-Yr) | Heat Rate (Btu/KWh) | Construction Schedule (Months) | POR (%) | FOR (%) | Minimum Load (%) |
|---|---|---|---|---|---|---|---|---|
| 2008 | 4,020 | – | – | – | – | – | – | – |
| 2010 | 3,830 | 15 | 95 | 14,500 | 36 | 7.6 | 9 | 40 |
| 2015 | 3,830 | 15 | 95 | 14,200 | 36 | 7.6 | 9 | 40 |
| 2020 | 3,830 | 15 | 95 | 14,000 | 36 | 7.6 | 9 | 40 |
| 2025 | 3,830 | 15 | 95 | 13,800 | 36 | 7.6 | 9 | 40 |
| 2030 | 3,830 | 15 | 95 | 13,500 | 36 | 7.6 | 9 | 40 |
| 2035 | 3,830 | 15 | 95 | 13,200 | 36 | 7.6 | 9 | 40 |
| 2040 | 3,830 | 15 | 95 | 13,000 | 36 | 7.6 | 9 | 40 |
| 2045 | 3,830 | 15 | 95 | 12,800 | 36 | 7.6 | 9 | 40 |
| 2050 | 3,830 | 15 | 95 | 12,500 | 36 | 7.6 | 9 | 40 |

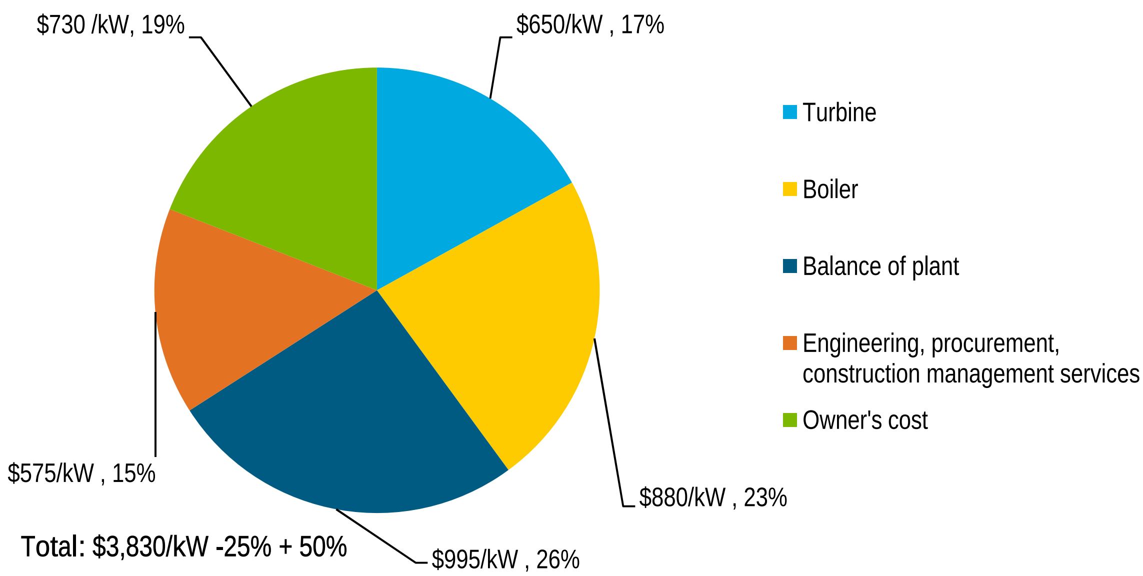


**Figure 5. Capital cost breakdown for a standalone biomass power plant**

## 3.2 GEOTHERMAL ENERGY TECHNOLOGIES

Hydrothermal technology is a relatively mature commercial technology for which cost improvement was not assumed. For enhanced geothermal systems (EGS) technology, Black & Veatch estimated future cost improvements based on improvements of geothermal fluid pumps and development of multiple, contiguous EGS units to benefit from economy of scale for EGS field development. The quality of geothermal resources are site- and resource-specific, therefore costs of geothermal resources can vary significantly from region to region. The cost estimates shown in this report are single-value generic estimates and may not be representative of any individual site. Table 20 and Table 21 present cost and performance data for hydrothermal and enhanced geothermal systems, respectively, based on these single-value estimates.

**Table 20. Cost and Performance Projection for a Hydrothermal Power Plant**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 6,240 | – | – | – | – | – |
| 2010 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2015 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2020 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2025 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2030 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2035 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2040 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2045 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2050 | 5,940 | 31 | 0 | 36 | 2.41 | 0.75 |

**Table 21. Cost and Performance Projection for an Enhanced Geothermal Systems Power Plant**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 10,400 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2010 | 9,900 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2015 | 9,720 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2020 | 9,625 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2025 | 9,438 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2030 | 9,250 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2035 | 8,970 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2040 | 8,786 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2045 | 8,600 | 31 | 0 | 36 | 2.41 | 0.75 |
| 2050 | 8,420 | 31 | 0 | 36 | 2.41 | 0.75 |

The capital cost breakdown for the hydrothermal geothermal power plant is shown in Figure 6.

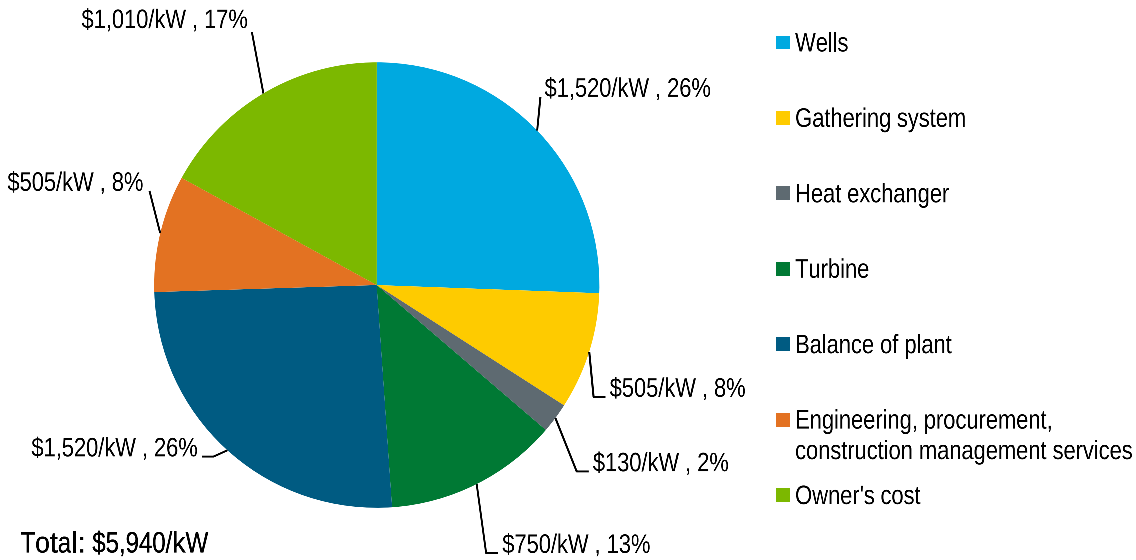


**Figure 6. Capital cost breakdown for a hydrothermal geothermal power plant**

The capital cost breakdown for the enhanced geothermal system power plant is shown in Figure 7.

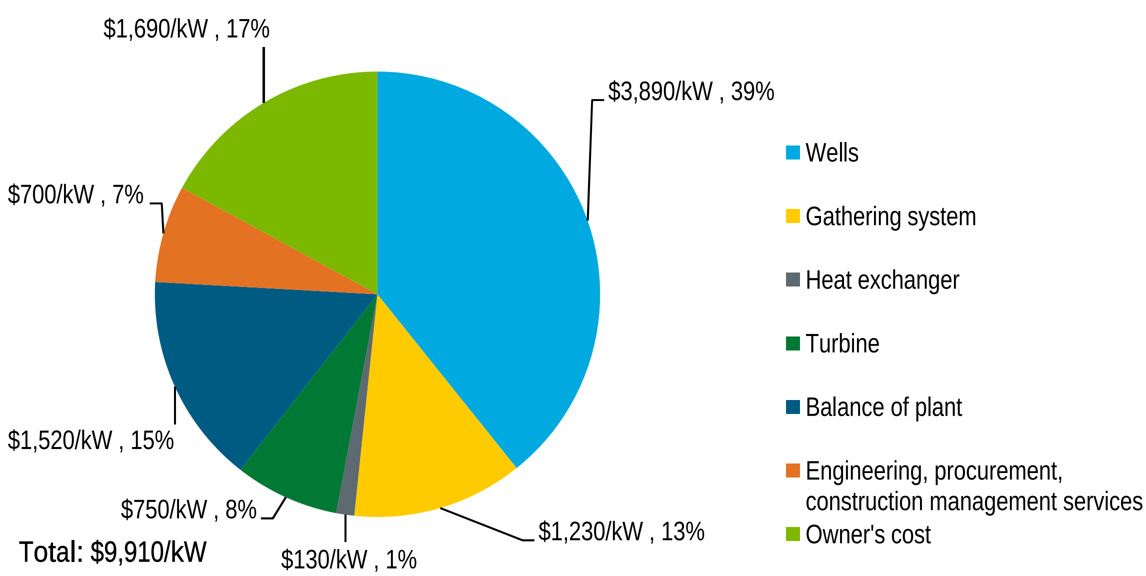


**Figure 7. Capital cost breakdown for an enhanced geothermal system power plant**

Enhanced geothermal system cost reductions will occur primarily in the wells, turbine, and BOP categories over time.

## 3.3 HYDROPOWER TECHNOLOGIES

Nearly 500 hydropower projects totaling more than 50,000 MW have been served by Black & Veatch worldwide. The Black & Veatch historical database incorporates a good understanding of hydroelectric costs. Black & Veatch used this historical background to develop the cost estimates vetted in the WREZ (Pletka and Finn 2009) stakeholder process and to subsequently update that pricing and adjust owner's costs as necessary.

Similar to geothermal technologies, the cost of hydropower technologies can be site-specific. Numerous options are available for hydroelectric generation; repowering an existing dam or generator, or installing a new dam or generator, are options. As such, the cost estimates shown in this report are single-value estimates and may not be representative of any individual site. 2010 capital cost for a 500 MW hydropower facility was estimated at 3,500 $/kW +35%. Table 22 presents cost and performance data for hydroelectric power technology.

**Table 22. Cost and Performance Data for a Hydroelectric Power Plant (500 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 3,600 | – | – | – | – | – |
| 2010 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2015 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2020 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2025 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2030 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2035 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2040 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2045 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |
| 2050 | 3,500 | 6 | 15 | 24 | 1.9 | 5.0 |

The capital cost breakdown for the hydroelectric power plant is shown in Figure 8.

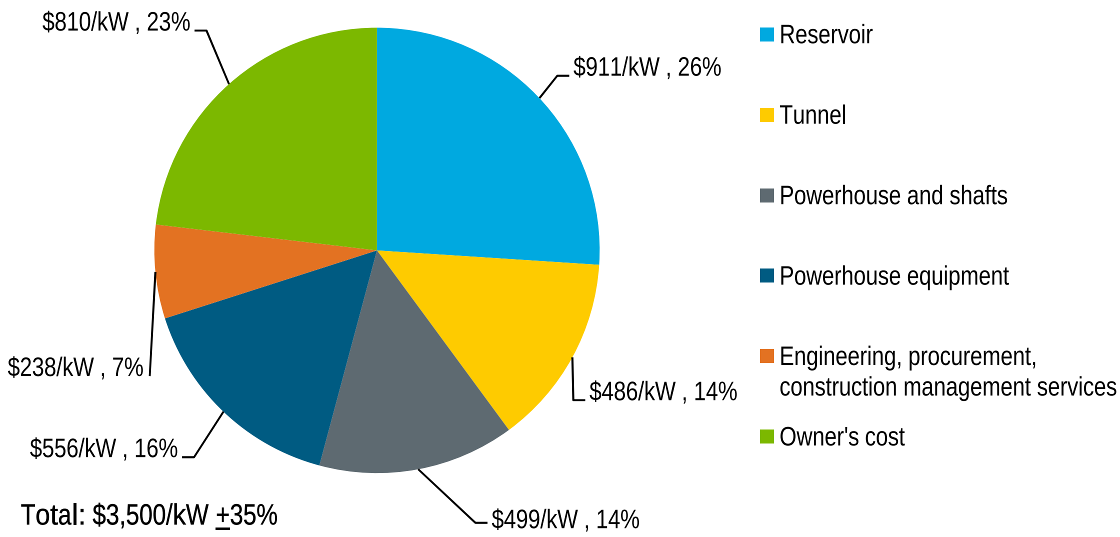


**Figure 8. Capital cost breakdown for a hydroelectric power plant**

Hydroelectric power plant cost reductions will be primarily in the power block cost category over time.

## 3.4 OCEAN ENERGY TECHNOLOGIES

Wave and tidal current resource assessment and technology costs were developed based on European demonstration and historical data obtained from studies. A separate assessment of the hydrokinetic resource uncertainty is included in Appendices A and B, informed by a Black & Veatch analysis that includes an updated resource assessment for wave and tidal current technologies and assumptions used to develop technology cost estimates. Wave capital cost in 2015 was estimated at 9,240 $/kW – 30% and +45%. This is an emerging technology with much uncertainty and many options available. A cost improvement of 63% was assumed through 2040 and then a cost increase through 2050reflecting the need to develop lower quality resources. Tidal current technology is similarly immature with many technical options. Capital cost in 2015 was estimated at 5,880 $/kW - 10% and + 20%. A cost improvement of 45% was assumed as the resource estimated to be available is fully utilized by 2030. Estimated O&M costs include insurance, seabed rentals, and other recurring costs that were not included in the one-time capital cost estimate. Wave O&M costs are higher than tidal current costs due to more severe conditions. Table 23 and

Table 24 present cost and performance for wave and tidal current technologies, respectively. The capital cost breakdown for wave and current power plants are shown in Figure 9 and Figure 10, respectively.

**Table 23. Cost and Performance Projection for Ocean Wave Technology**

| Year | Capital Cost ($/kW) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|
| 2015 | 9,240 | 474 | 24 | 1 | 7 |
| 2020 | 6,960 | 357 | 24 | 1 | 7 |
| 2025 | 5,700 | 292 | 24 | 1 | 7 |
| 2030 | 4,730 | 243 | 24 | 1 | 7 |
| 2035 | 3,950 | 203 | 24 | 1 | 7 |
| 2040 | 3,420 | 175 | 24 | 1 | 7 |
| 2045 | 4,000 | 208 | 24 | 1 | 7 |
| 2050 | 5,330 | 273 | 24 | 1 | 7 |

**Table 24. Cost and Performance Projection for Ocean Tidal Current Technology**

| Year | Capital Cost ($/kW) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|
| 2015 | 5,880 | 198 | – | – | – |
| 2020 | 4,360 | 147 | 24 | 1.0 | 6.5 |
| 2025 | 3,460 | 117 | 24 | 1.0 | 6.5 |
| 2030 | 3,230 | 112 | 24 | 1.0 | 6.5 |
| 2035 | – | 112 | 24 | 1.0 | 6.5 |
| 2040 | – | 112 | 24 | 1.0 | 6.5 |
| 2045 | – | 112 | 24 | 1.0 | 6.5 |
| 2050 | – | 112 | 24 | 1.0 | 6.5 |

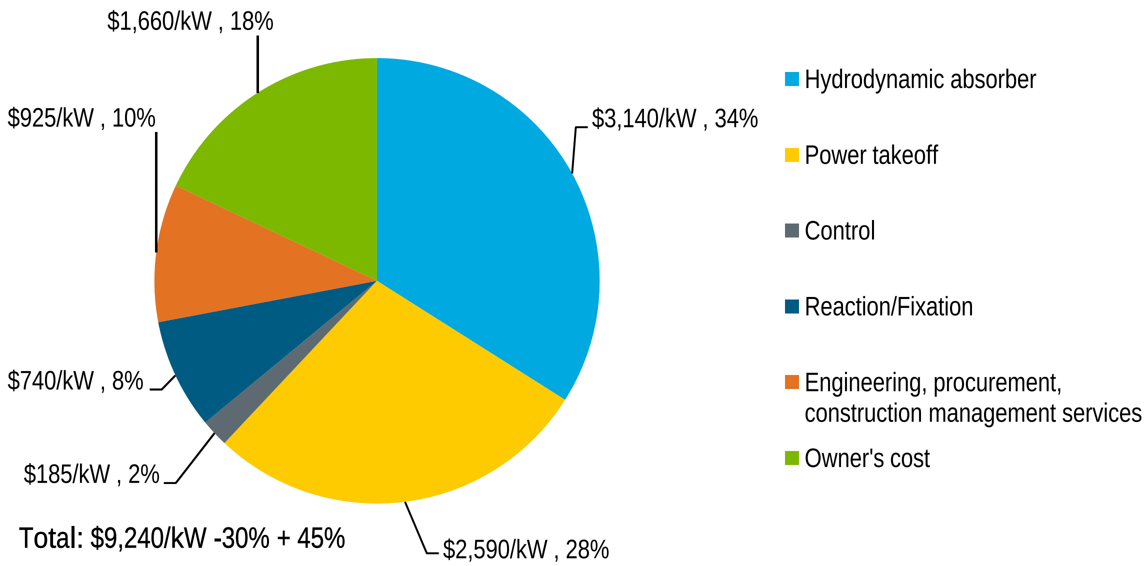


**Figure 9. Capital cost breakdown for an ocean wave power plant**

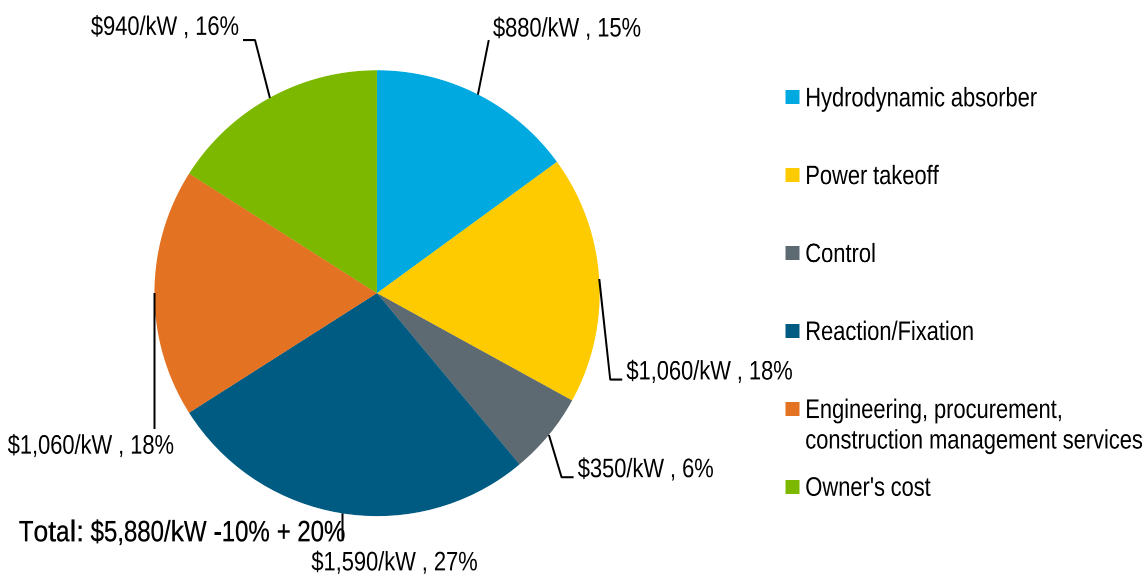


**Figure 10. Capital cost breakdown for an ocean tidal power plant**

Appendices A and B highlight the uncertainty associated with estimates of wave and tidal energy resources. They form the basis for the estimates above.

## 3.5 SOLAR ENERGY TECHNOLOGIES

### 3.5.1 Solar Photovoltaic Technologies

Black & Veatch has been involved in the development of utility scale solar photovoltaic (PV) systems, including siting support, interconnection support, technology due diligence, and conceptual layout. Specifically Black & Veatch has performed due diligence on more than 200 MW of utility scale PV projects for lenders and owners as well as assisted in the development of more than 1,500 MW of projects for utilities and developers. Black & Veatch has been the independent engineer for 35 distributed PV projects totaling 16 MW in California and an independent engineer for two of the largest PV systems in North America. It has also reviewed solar PV new PPA pricing and done project and manufacturer due diligence investigations. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs.

Estimates for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC) are provided. The capital costs were assumed to have uncertainties of +25%. Cost uncertainty is not high for current offerings but over time, a number of projected, potential technology improvements may affect costs for this technology. Choosing the non-tracking utility PV with a 100-MW (DC) size as a representative case, a 35% reduction in cost was expected through 2050. Table 25 presents cost and performance data for a wide range of PV systems. Table 25 includes 2008 costs to illustrate the impact (in constant 2009 dollars) of the commodity price drop that occurred between 2008 and 2010. For most generation technologies, the decline in commodity prices over the two years results in a 3%–5% reduction in capital cost. As seen in Table 25, the drop in PV technology costs is significantly greater. For PV, the 2008 costs were based on actual market data adjusted to 2009 dollars. Over these two years, PV experienced a drastic fall in costs, due to technology improvements, economies of scale, increased supply in raw materials, and other factors. The capital cost breakdown for the PV power plant (non-tracking Utility PV with a 10 MW (DC) install size) is shown in Figure 11. Note that 100-MW utility PV systems representing nth plant configurations are not available in 2010.

**Table 25. Cost and Performance Projection for Solar Photovoltaic Technology**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| Residential PV with a 4 kW (DC) install size | | | | | | |
| 2008 | 7690 | – | – | – | – | – |
| 2010 | 5950 | 0 | 50 | 2.0 | 2.0 | 0.0 |
| 2015 | 4340 | 0 | 48 | 1.9 | 2.0 | 0.0 |
| 2020 | 3750 | 0 | 45 | 1.8 | 2.0 | 0.0 |
| 2025 | 3460 | 0 | 43 | 1.7 | 2.0 | 0.0 |

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2030 | 3290 | 0 | 41 | 1.6 | 2.0 | 0.0 |
| 2035 | 3190 | 0 | 39 | 1.5 | 2.0 | 0.0 |
| 2040 | 3090 | 0 | 37 | 1.5 | 2.0 | 0.0 |
| 2045 | 3010 | 0 | 35 | 1.4 | 2.0 | 0.0 |
| 2050 | 2930 | 0 | 33 | 1.3 | 2.0 | 0.0 |
| **Commercial PV with a 100 kW (DC) install size** | | | | | | |
| 2008 | 5610 | – | – | – | – | – |
| 2010 | 4790 | 0 | 50 | 6.0 | 2.0 | 0.0 |
| 2015 | 3840 | 0 | 48 | 5.7 | 2.0 | 0.0 |
| 2020 | 3340 | 0 | 45 | 5.4 | 2.0 | 0.0 |
| 2025 | 3090 | 0 | 43 | 5.1 | 2.0 | 0.0 |
| 2030 | 2960 | 0 | 41 | 4.9 | 2.0 | 0.0 |
| 2035 | 2860 | 0 | 39 | 4.6 | 2.0 | 0.0 |
| 2040 | 2770 | 0 | 37 | 4.4 | 2.0 | 0.0 |
| 2045 | 2690 | 0 | 35 | 4.2 | 2.0 | 0.0 |
| 2050 | 2620 | 0 | 33 | 4.0 | 2.0 | 0.0 |
| **Non-Tracking Utility PV with a 1-MW (DC) Install Size** | | | | | | |
| 2008 | 4610 | – | – | – | – | – |
| 2010 | 3480 | 0 | 50 | 8.0 | 2.0 | 0.0 |
| 2015 | 3180 | 0 | 48 | 7.6 | 2.0 | 0.0 |
| 2020 | 3010 | 0 | 45 | 7.2 | 2.0 | 0.0 |
| 2025 | 2880 | 0 | 43 | 6.9 | 2.0 | 0.0 |
| 2030 | 2760 | 0 | 41 | 6.5 | 2.0 | 0.0 |
| 2035 | 2660 | 0 | 39 | 6.2 | 2.0 | 0.0 |
| 2040 | 2570 | 0 | 37 | 5.9 | 2.0 | 0.0 |
| 2045 | 2490 | 0 | 35 | 5.6 | 2.0 | 0.0 |
| 2050 | 2420 | 0 | 33 | 5.3 | 2.0 | 0.0 |
| **Non-Tracking Utility PV with a 10-MW (DC) Install Size** | | | | | | |
| 2008 | 3790 | – | – | – | – | – |
| 2010 | 2830 | 0 | 50 | 12.0 | 2.0 | 0.0 |

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2015 | 2550 | 0 | 48 | 11.4 | 2.0 | 0.0 |
| 2020 | 2410 | 0 | 45 | 10.8 | 2.0 | 0.0 |
| 2025 | 2280 | 0 | 43 | 10.3 | 2.0 | 0.0 |
| 2030 | 2180 | 0 | 41 | 9.8 | 2.0 | 0.0 |
| 2035 | 2090 | 0 | 39 | 9.3 | 2.0 | 0.0 |
| 2040 | 2010 | 0 | 37 | 8.8 | 2.0 | 0.0 |
| 2045 | 1940 | 0 | 35 | 8.4 | 2.0 | 0.0 |
| 2050 | 1870 | 0 | 33 | 8.0 | 2.0 | 0.0 |
| Non-Tracking Utility PV with a 100-MW (DC) Install Size | | | | | | |
| 2008 | 3210 | – | – | – | – | – |
| 2010 | | | | | | |
| 2015 | 2357 | 0 | 48 | 17.1 | 2.0 | 0.0 |
| 2020 | 2220 | 0 | 45 | 16.2 | 2.0 | 0.0 |
| 2025 | 2100 | 0 | 43 | 15.4 | 2.0 | 0.0 |
| 2030 | 1990 | 0 | 41 | 14.7 | 2.0 | 0.0 |
| 2035 | 1905 | 0 | 39 | 13.9 | 2.0 | 0.0 |
| 2040 | 1830 | 0 | 37 | 13.2 | 2.0 | 0.0 |
| 2045 | 1760 | 0 | 35 | 12.6 | 2.0 | 0.0 |
| 2050 | 1700 | 0 | 33 | 11.9 | 2.0 | 0.0 |
| 1-Axis Tracking Utility PV with a 1-MW (DC) Install Size | | | | | | |
| 2008 | 5280 | – | – | – | – | – |
| 2010 | 3820 | 0 | 50 | 10.0 | 2.0 | 0.0 |
| 2015 | 3420 | 0 | 48 | 9.5 | 2.0 | 0.0 |
| 2020 | 3100 | 0 | 45 | 9.0 | 2.0 | 0.0 |
| 2025 | 2940 | 0 | 43 | 8.6 | 2.0 | 0.0 |
| 2030 | 2840 | 0 | 41 | 8.1 | 2.0 | 0.0 |
| 2035 | 2750 | 0 | 39 | 7.7 | 2.0 | 0.0 |
| 2040 | 2670 | 0 | 37 | 7.4 | 2.0 | 0.0 |
| 2045 | 2590 | 0 | 35 | 7.0 | 2.0 | 0.0 |
| 2050 | 2520 | 0 | 33 | 6.6 | 2.0 | 0.0 |

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| **1-Axis Tracking Utility PV with a 10-MW (DC) Install Size** | | | | | | |
| 2008 | 4010 | – | – | – | – | – |
| 2010 | 3090 | 0 | 50 | 14.0 | 2.0 | 0.0 |
| 2015 | 2780 | 0 | 48 | 13.3 | 2.0 | 0.0 |
| 2020 | 2670 | 0 | 45 | 12.6 | 2.0 | 0.0 |
| 2025 | 2560 | 0 | 43 | 12.0 | 2.0 | 0.0 |
| 2030 | 2380 | 0 | 41 | 11.4 | 2.0 | 0.0 |
| 2035 | 2380 | 0 | 39 | 10.8 | 2.0 | 0.0 |
| 2040 | 2300 | 0 | 37 | 10.3 | 2.0 | 0.0 |
| 2045 | 2230 | 0 | 35 | 9.8 | 2.0 | 0.0 |
| 2050 | 2170 | 0 | 33 | 9.3 | 2.0 | 0.0 |
| **1-Axis Tracking Utility PV with a 100-MW (DC) Install Size** | | | | | | |
| 2008 | 3920 | – | – | – | – | – |
| 2010 | | | | | | |
| 2015 | 2620 | 0 | 48 | 13.3 | 2.0 | 0.0 |
| 2020 | 2510 | 0 | 45 | 12.6 | 2.0 | 0.0 |
| 2025 | 2410 | 0 | 43 | 12.0 | 2.0 | 0.0 |
| 2030 | 2310 | 0 | 41 | 11.4 | 2.0 | 0.0 |
| 2035 | 2230 | 0 | 39 | 10.8 | 2.0 | 0.0 |
| 2040 | 2160 | 0 | 37 | 10.3 | 2.0 | 0.0 |
| 2045 | 2090 | 0 | 35 | 9.8 | 2.0 | 0.0 |
| 2050 | 2030 | 0 | 33 | 9.3 | 2.0 | 0.0 |

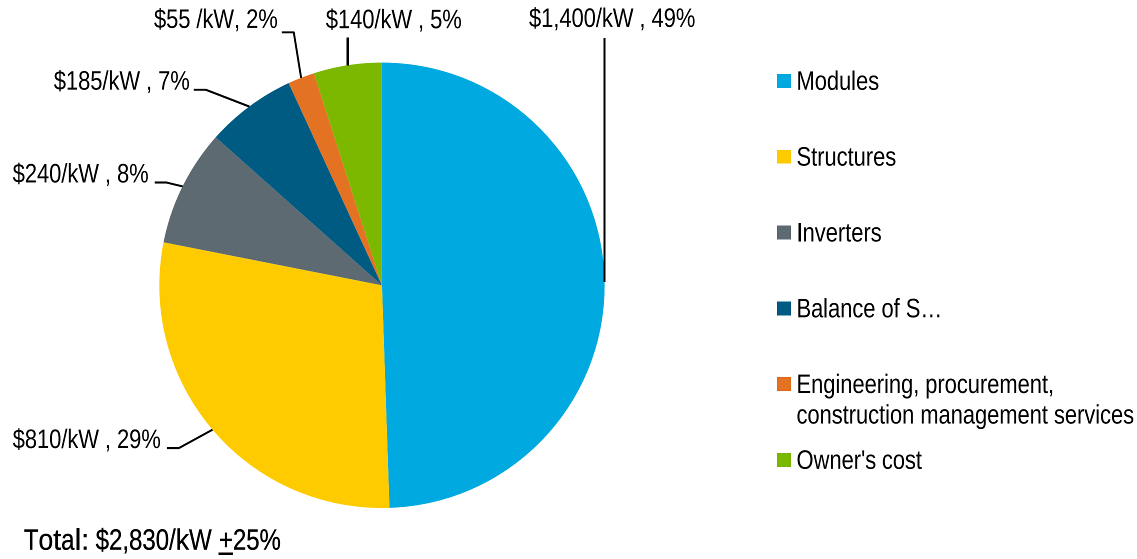


**Figure 11. Capital cost breakdown for a solar photovoltaic power plant**

Appendix C presents further breakdowns for photovoltaic costs.

### 3.5.2 Concentrating Solar Power Technologies

Black & Veatch has participated in numerous concentrating solar power (CSP) pilot plant and study activities since the 1970s. The company has been the independent engineer for CSP projects and has performed due diligence on CSP manufacturers. Black & Veatch has also reviewed costs in new CSP purchase agreements. This historical knowledge and recent market data was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and make adjustments to owner's costs.

Multiple CSP options were represented, including CSP without storage and CSP with storage. The CSP without storage option was assumed to be represented by trough systems for all years. For the CSP option with storage, the cost data represented trough systems until 2025, after which, tower systems were represented. These model assumptions do not represent CSP technology choice predictions by Black & Veatch. The location assumed for costing of CSP systems is the Southwest United States, not the Midwest as used for other technologies. All CSP systems were based on dry-cooled technologies. The cost and performance data presented here were based on 200-MW net power plants. Multiple towers were used in the tower configuration.

Black & Veatch estimated capital costs to be 4,910 $/kW -35% and +15% without storage and 7,060 $/kW -35% and +15% with storage for 2010. There is greater downside potential than upside cost growth due to the expected emergence of new technology options. New CSP technologies are expected to be commercialized before 2050, and 30%-33% capital cost improvements were assumed for all systems through 2050. Table 26 and Table 27present cost and performance data for CSP power plants without and with storage, respectively. For the with storage option, trough costs were represented in years up to and including 2025; tower costs were provided after 2025. Capital cost breakdown for the 2010 CSP plants with storage are shown in Figure 12 and Figure 13 for trough and tower systems, respectively.

**Table 26. Cost and Performance Projection for a Concentrating Solar Power Plant without Storagea**

| Year | Capital Cost ($/kW) | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/kW-Yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 5,050 | – | – | – | – | – |
| 2010 | 4,910 | 0 | 50 | 24 | 0 | 6 |
| 2015 | 4,720 | 0 | 50 | 24 | 0 | 6 |
| 2020 | 4,540 | 0 | 50 | 24 | 0 | 6 |
| 2025 | 4,350 | 0 | 50 | 24 | 0 | 6 |
| 2030 | 4,170 | 0 | 50 | 24 | 0 | 6 |
| 2035 | 3,987 | 0 | 50 | 24 | 0 | 6 |
| 2040 | 3,800 | 0 | 50 | 24 | 0 | 6 |
| 2045 | 3,620 | 0 | 50 | 24 | 0 | 6 |
| 2050 | 3,430 | 0 | 50 | 24 | 0 | 6 |

[a] Concentrating solar power dry cooling, no storage, and a solar multiple of 1.4.

**Table 27. Cost and Performance Projection for a Concentrating Solar Power Plant with Storagea**

| Year | Capital Cost ($/kW) | Variable O&M Cost ($/MWh) | Fixed O&M Cost ($/kW-Yr) | Construction Schedule (months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 7280 | – | – | – | – | – |
| 2010 | 7060 | 0 | 50 | 24 | 0 | 6 |
| 2015 | 6800 | 0 | 50 | 24 | 0 | 6 |
| 2020 | 6530 | 0 | 50 | 24 | 0 | 6 |
| 2025 | 5920 | 0 | 50 | 24 | 0 | 6 |
| 2030 | 5310 | 0 | 50 | 24 | 0 | 6 |
| 2035 | 4700 | 0 | 50 | 24 | 0 | 6 |
| 2040 | 4700 | 0 | 50 | 24 | 0 | 6 |
| 2045 | 4700 | 0 | 50 | 24 | 0 | 6 |
| 2050 | 4700 | 0 | 50 | 24 | 0 | 6 |

[a] Concentrating solar power dry cooling, 6-hour storage, and a solar multiple of 2.

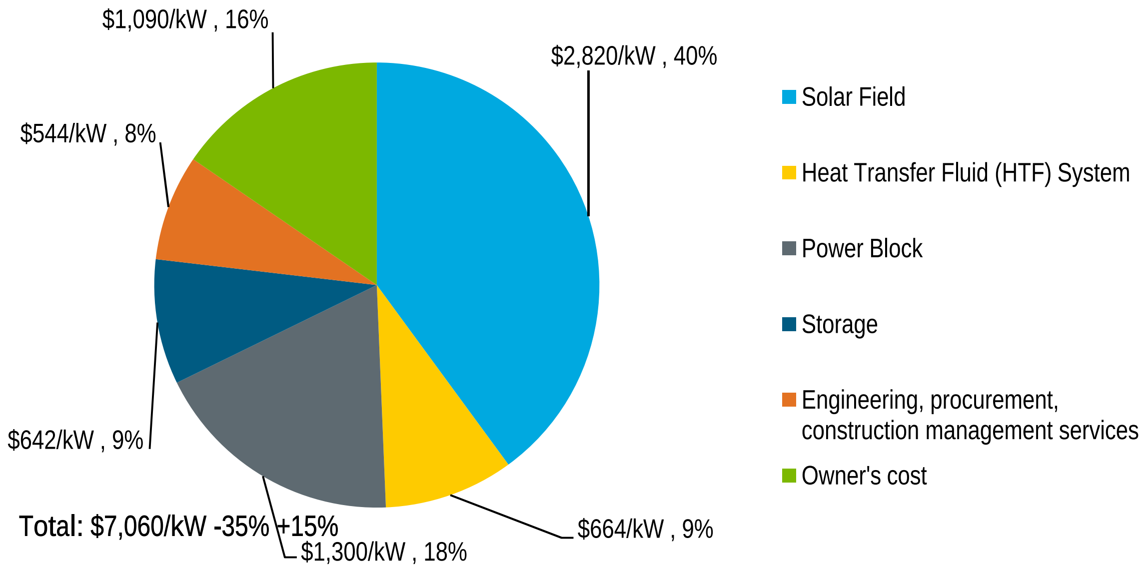


**Figure 12. Capital cost breakdown for a trough concentrating solar power plant with storage**

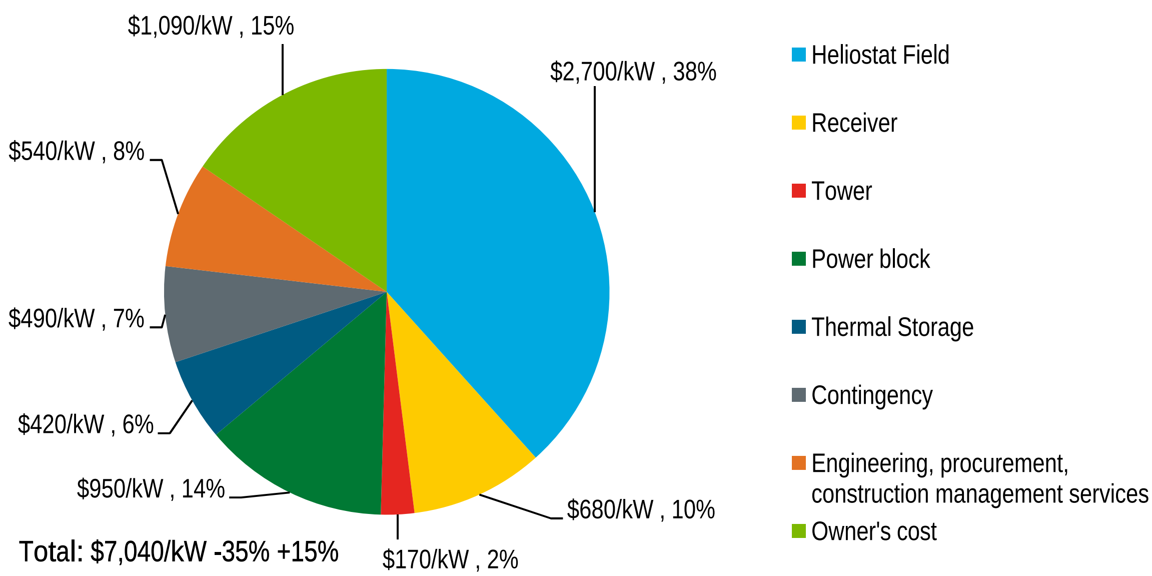


**Figure 13. Capital cost breakdown for a tower concentrating solar power plant with storage**

## 3.6 WIND ENERGY TECHNOLOGIES

Black & Veatch has experience achieved in 10,000 MW of wind engineering, development, and due diligence projects from 2005 to 2010. In addition, significant understanding of the details of wind cost estimates was obtained by performing 300 MW of detailed design and 300 MW of construction services in 2008. Black & Veatch also has reviewed wind project PPA pricing. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs. Costs are provided for onshore, fixed-bottom offshore and floating-platform offshore wind turbine installations. These cost and performance estimates are slightly more conservative than estimates identified in O'Connell and Pletka 2007 for the "20% Wind Energy by 2030" study. Improvements seen since 2004 to 2006 have been somewhat less than previously estimated as the technology more fully matures. Additional improvement is expected but at a slightly slower pace. There is both increased cost and increased performance uncertainty for floating-platform offshore systems.

### 3.6.1 Onshore Technology

Black & Veatch estimated a capital cost at 1,980 $/kW +25%. Cost certainty is relatively high for this maturing technology and no cost improvements were assumed through 2050. Capacity factor improvements were assumed until 2030; further improvements were not assumed to be achievable after 2030.

### 3.6.2 Fixed-Bottom Offshore Technology

Fixed-bottom offshore wind projects were assumed to be at a depth that allows erection of a tall tower with a foundation that touches the sea floor. Historical data for fixed-bottom offshore wind EPC projects are not generally available in the United States, but NREL reviewed engineering studies and published data for European projects. Black & Veatch estimated a capital cost at 3,310 $/kW +35%. Cost and capacity factor improvements were assumed to be achievable before 2030; cost improvements of approximately 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes through 2030.

### 3.6.3 Floating-Platform Offshore Technology

Floating-platform offshore wind technology was assumed to be needed in water depths where a tall tower and foundation is not cost effective/feasible. Black & Veatch viewed the floating-platform wind turbine cost estimates as much more speculative. This technology was assumed to be unavailable in the United States until 2020. Fewer studies and published sources exist compared with onshore and fixed-bottom offshore systems. Black & Veatch estimated a 2020 capital cost at 4,200 $/kW +35%. Cost improvements of 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes until 2030.

Table 28 through Table 33 present wind cost and performance data, including capacity factors, for onshore, fixed-bottom offshore, and floating-platform offshore technologies. Capital cost breakdowns for these technologies are shown in Figure 14 through Figure 16.

**Table 28. Cost and Performance Projection for Onshore Wind Technology**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 2,060 | – | – | – | – | – |
| 2010 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2015 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2020 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2025 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2030 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2035 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2040 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2045 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |
| 2050 | 1,980 | 0 | 60 | 12 | 0.6 | 5 |

**Table 29. Capacity Factor Projection for Onshore Wind Technology**

| | Capacity Factor (%) | | | | |
|---|---|---|---|---|---|
| Year | Class 3 | Class 4 | Class 5 | Class 6 | Class 7 |
| 2010 | 32 | 36 | 41 | 44 | 46 |
| 2015 | 33 | 37 | 41 | 44 | 46 |
| 2020 | 33 | 37 | 42 | 44 | 46 |
| 2025 | 34 | 38 | 42 | 45 | 46 |
| 2030 | 35 | 38 | 43 | 45 | 46 |
| 2035 | 35 | 38 | 43 | 45 | 46 |
| 2040 | 35 | 38 | 43 | 45 | 46 |
| 2045 | 35 | 38 | 43 | 45 | 46 |
| 2050 | 35 | 38 | 43 | 45 | 46 |

**Table 30. Cost and Performance Projection for Fixed-bottom Offshore Wind Technology**

| Year | Capita Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2008 | 3,410 | – | – | – | – | – |
| 2010 | 3,310 | 0 | 100 | 12 | 0.6 | 5 |
| 2015 | 3,230 | 0 | 100 | 12 | 0.6 | 5 |
| 2020 | 3,150 | 0 | 100 | 12 | 0.6 | 5 |
| 2025 | 3,070 | 0 | 100 | 12 | 0.6 | 5 |
| 2030 | 2,990 | 0 | 100 | 12 | 0.6 | 5 |
| 2035 | 2,990 | 0 | 100 | 12 | 0.6 | 5 |
| 2040 | 2,990 | 0 | 100 | 12 | 0.6 | 5 |
| 2045 | 2,990 | 0 | 100 | 12 | 0.6 | 5 |
| 2050 | 2,990 | 0 | 100 | 12 | 0.6 | 5 |

**Table 31. Capacity Factor Projection for Fixed-bottom Offshore Wind Technology**

| | Capacity Factor (%) | | | | |
|---|---|---|---|---|---|
| Year | Class 3 | Class 4 | Class 5 | Class 6 | Class 7 |
| 2010 | 36 | 39 | 45 | 48 | 50 |
| 2015 | 36 | 39 | 45 | 48 | 50 |
| 2020 | 37 | 39 | 45 | 48 | 50 |
| 2025 | 37 | 40 | 45 | 48 | 50 |
| 2030 | 38 | 40 | 45 | 48 | 50 |
| 2035 | 38 | 40 | 45 | 48 | 50 |
| 2040 | 38 | 40 | 45 | 48 | 50 |
| 2045 | 38 | 40 | 45 | 48 | 50 |
| 2050 | 38 | 40 | 45 | 48 | 50 |

**Table 32. Cost and Performance Projection for Floating-Platform Offshore Wind Technology**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-Yr) | Construction Schedule (Months) | POR (%) | FOR (%) |
|---|---|---|---|---|---|---|
| 2020 | 4,200 | 0 | 130 | 12 | 0.6 | 5 |
| 2025 | 4,090 | 0 | 130 | 12 | 0.6 | 5 |
| 2030 | 3,990 | 0 | 130 | 12 | 0.6 | 5 |
| 2035 | 3,990 | 0 | 130 | 12 | 0.6 | 5 |
| 2040 | 3,990 | 0 | 130 | 12 | 0.6 | 5 |
| 2045 | 3,990 | 0 | 130 | 12 | 0.6 | 5 |
| 2050 | 3,990 | 0 | 130 | 12 | 0.6 | 5 |

**Table 33. Capacity Factor Projection for Floating-Platform Offshore Wind Technology**

| | Capacity Factor (%) | | | | |
|---|---|---|---|---|---|
| Year | Class 3 | Class 4 | Class 5 | Class 6 | Class 7 |
| 2020 | 37 | 39 | 45 | 48 | 50 |
| 2025 | 37 | 40 | 45 | 48 | 50 |
| 2030 | 38 | 40 | 45 | 48 | 50 |
| 2035 | 38 | 40 | 45 | 48 | 50 |
| 2040 | 38 | 40 | 45 | 48 | 50 |
| 2045 | 38 | 40 | 45 | 48 | 50 |
| 2050 | 38 | 40 | 45 | 48 | 50 |

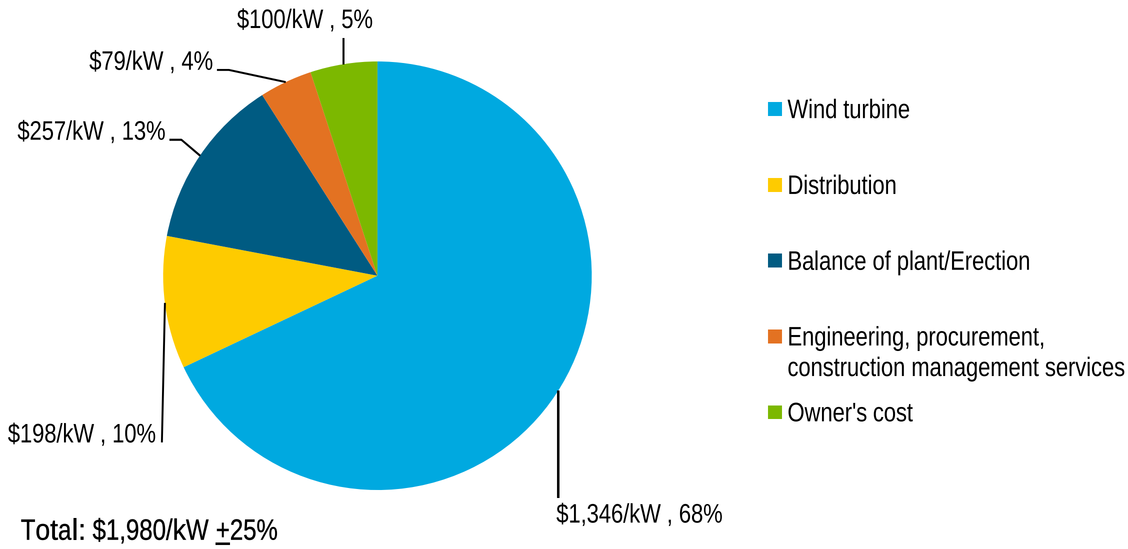


**Figure 14. Capital cost breakdown for an onshore wind power plant**

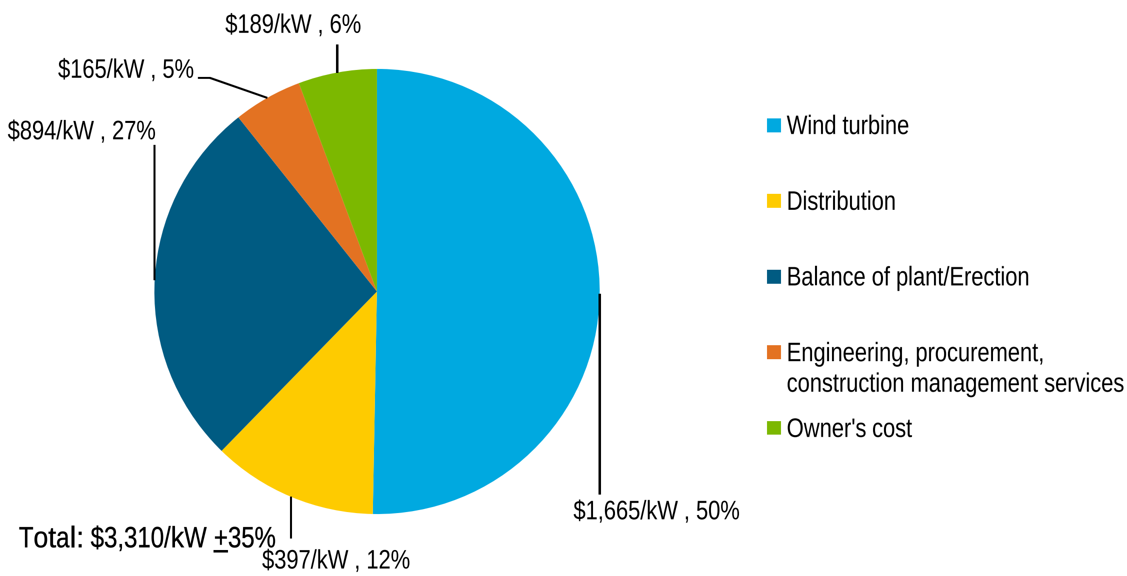


**Figure 15. Capital cost breakdown for a fixed-bottom offshore wind power plant**

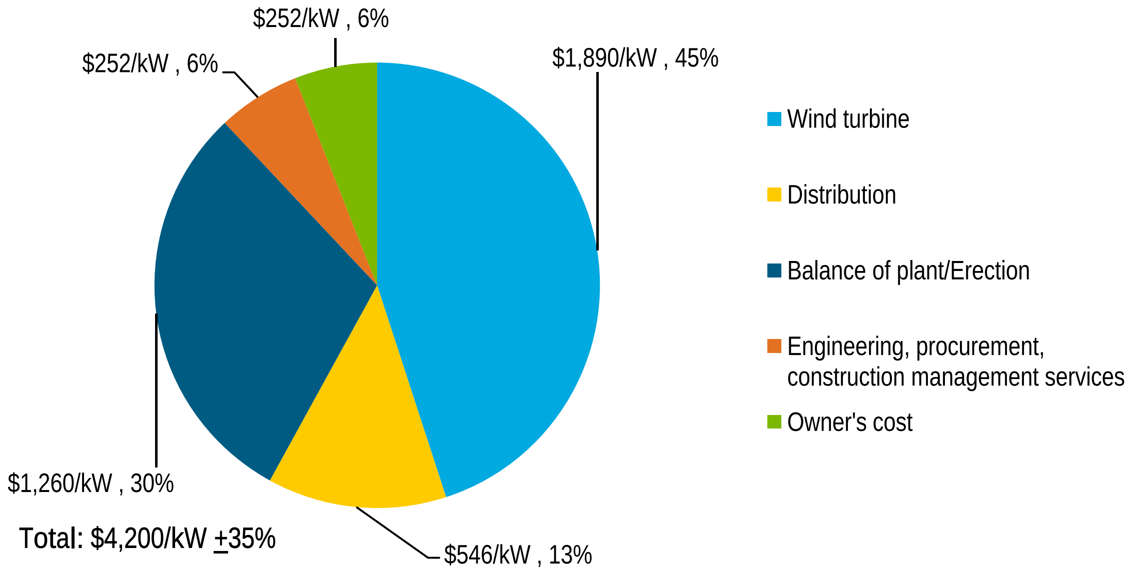


**Figure 16. Capital cost breakdown for a floating-platform offshore wind power plant**

# 4 Cost and Performance Data for Energy Storage Technologies

Selecting a representative project definition for compressed air energy storage (CAES) and pumped-storage hydropower (PSH) technologies that can then be used to identify a representative cost is extremely difficult; one problem is that a very low cost can be estimated for these technologies if the best circumstances are assumed (e.g., use of existing infrastructure). For example, an assumption can be made for CAES that almost no below ground cost is contributed when building a small project that can be accommodated by an abandoned gas well of adequate size. For PSH, one can assume only two existing reservoirs need to be connected with a pump and turbine at the lower reservoir. These low cost solutions can be compared to high cost solutions; for CAES, excavation of an entire cavern out of hard rock could be assumed, and for PSH construction of new reservoirs and supply of pump/turbine and interconnections between reservoirs could be assumed. These scenarios are entirely different from possible low cost or mid-cost options. While this situation makes identifying a representative, or average, project difficult, this selection must be made before the discussion of costs can be opened. The design options and associated costs for CAES and PSH are unlimited. History is no help because circumstances are now different from those that existed when the previous generation of pumped hydropower was built and because there are not a large number of existing CAES units to review. Another issue with PSH is that transmission has been equally challenging with cost and environmental issues limiting pumped options.

No CAES or PSH plants have been built recently. Further, in the case of PCH, the Electric Power Research Institute has indicated, “scarcity of suitable surface topography that is environmentally acceptable is likely to inhibit further significant domestic development of utility pumped-hydro storage.”5

Black & Veatch initially selected point estimates for CAES and PSH with ranges around points that can capture a broad range of project configuration assumptions. The disadvantage of the storage estimates initially selected is that they might not adequately reflect the very lowest cost options that may eventually be available. However, the advantage is that they are examples of what real developers have recently considered for development; developers have considered projects with these costs and descriptions to be worthy of study. They are not the least cost examples that could someday be available for consideration by developers, but they are recent examples of site and technology combinations that developers actually have had available for consideration. In addition, the PSH example is of relatively small capacity that may be suitable in a larger number of locations; it is not a less expensive, larger capacity system that may not be as available in many parts of the country. Lastly, because Black & Veatch views the costs as mid-range, they may be considered reasonably conservative. Black & Veatch recognizes that it could have chosen lower cost cases, but the cases initially shown here are representative of projects that developers have actually recently considered.

[5] Pumped Hydroelectric Storage, http://www.rkmaonline.com/utilityenergystorageSAMPLE.pdf

## 4.1 COMPRESSED AIR ENERGY STORAGE (CAES) TECHNOLOGY

A confidential CAES in-house reference study for an independent power producer has been used for the point estimate, and the range was based on historical data. A two-unit recuperated expander with storage in a solution-mined salt dome was assumed for this estimate. Approximately 262 MW net with 15 hours of storage was assumed to be provided. Five compressors were assumed to be included. A 2010capital cost was estimated at 900 $/kW -30% + 75%. No cost improvement was assumed over time . Table 34 presents costs and performance data for CAES. Table 535 presents emission data for the technology.

**Table 34. Cost and Performance Projection for a Compressed Air Energy Storage Plant (262 MW)**

| Year | Heat Rate (Btu/kWh) | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-year) | Round-Trip Efficiency | FOR (%) | POR (%) | Construction Schedule (Months) | Min. Load (%) | Spin Ramp Rate (%/min.) | Quick Start Ramp Rate (%/min.) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 4910 | 927 | – | – | – | – | – | – | – | – | – |
| 2010 | – | – | – | – | – | – | – | – | – | – | – |
| 2015 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2020 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2025 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2030 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2035 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2040 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2045 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |
| 2050 | 4910 | 900 | 1.55 | 11.6 | 1.25 | 3 | 4 | 18 | 50 | 10 | 4 |

**Table 35. Emission Rates for Compressed Air Energy Storage**

| $SO_2$ (lb/ hr) | $NO_X$ (lb/hr) | Hg Micro (lb/hr) | PM10 (lb/hr) | $CO_2$ (kpph) |
|---|---|---|---|---|
| 3.4 | 47 | 0 | 11.6 | 135 |

The capital cost breakdown for the CAES plant is shown in Figure 17.

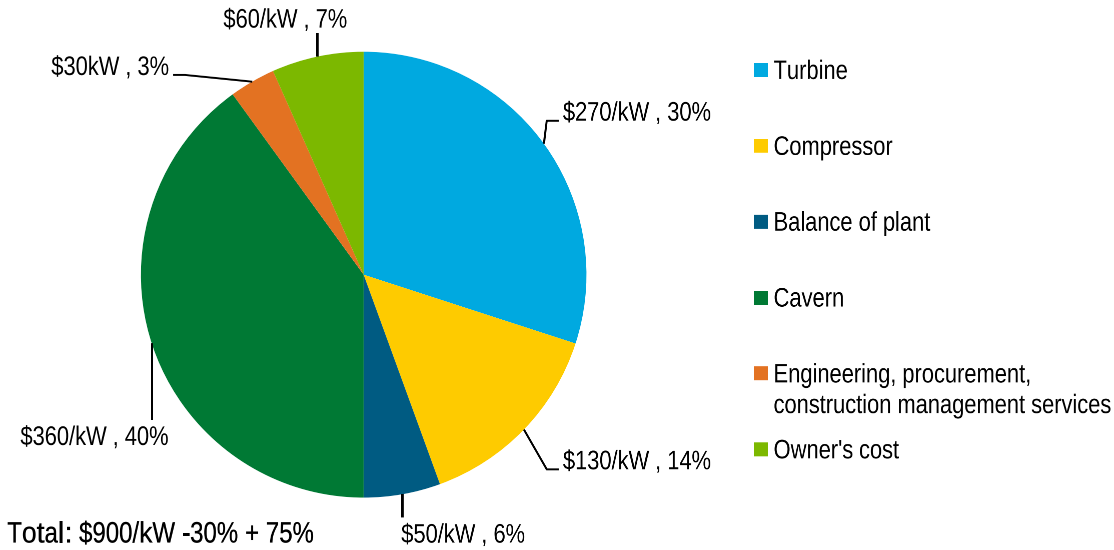


**Figure 17. Capital cost breakdown for a compressed air energy storage power plant**

CAES plant cost savings will occur in all cost categories over time.

## 4.2 PUMPED-STORAGE HYDROPOWER TECHNOLOGY

A confidential in-house reference study for an independent power producer was used for the point estimate, and the range was established based on historical data. The PSH cost estimate assumed a net capacity of 500 MW with 10 hours of storage. A 2010 capital cost was estimated at 2,004 $/kW +50%. Appendix D provides additional detail on cost considerations for PSH technologies. This is a mature technology with no cost improvement assumed over time.. A list of current FERC preliminary licenses indicates an average size between 500 and 800 MW. Cost and performance data for PSH are presented in Table 36.

**Table 36. Cost and Performance Projection for a Pumped-Storage Hydropower Plant (500 MW)**

| Year | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Round-Trip Efficiency (%) | FOR (%) | POR (%) | Construction Schedule (Months) | Min. Load (%) | Spin Ramp Rate (%/min.) | Quick Start Ramp Rate (%/min.) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 2297 | – | – | – | – | – | – | – | – | – |
| 2010 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2015 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2020 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2025 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2030 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2035 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2040 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2045 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |
| 2050 | 2230 | 0 | 30.8 | 0.8 | 3.00 | 3.80 | 30 | 33 | 50 | 50 |

The capital cost breakdown for the pumped-storage hydropower plant is shown in Figure 18.

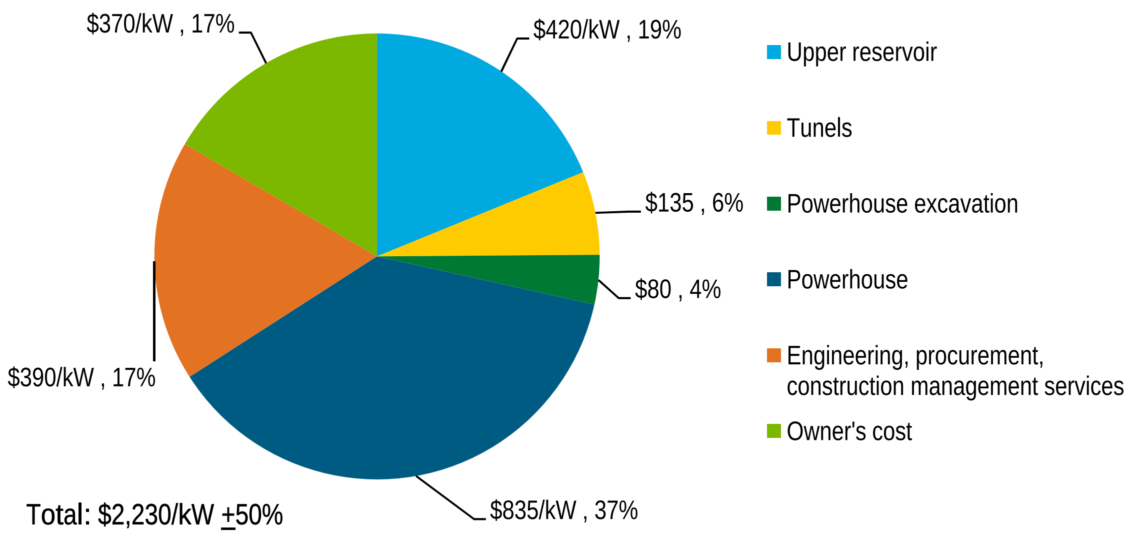


**Figure 18. Capital Cost breakdown for a pumped-storage hydropower plant**

Pumped hydroelectric power plant cost savings will occur primarily in the powerhouse category over time.

## 4.3 BATTERY ENERGY STORAGE TECHNOLOGY

A confidential in-house reference study for an independent power producer has been used for the point estimate, and the range has been established based on historical data. The battery proxy was assumed to be a sodium sulfide type with a net capacity of 7.2 MW. The storage was assumed to be 8.1 hours. A capital cost is estimated at 3,990 $/kW (or 1,000 $/kW and 350 $/kWh) +75%. Cost improvement over time was assumed for development of a significant number of new battery options. Table 37 presents cost and performance data for battery energy storage. The O&M cost includes the cost of battery replacement every 5,000 hours.

**Table 37. Cost and Performance Projection for a Battery Energy Storage Plant (7.2 MW)**

| (Year) | Capital Cost ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-yr) | Round-Trip Efficiency (%) | FOR (%) | POR (%) | Construction Schedule (Months) | Min. Load (%) | Spin Ramp Rate (%/sec) | Quick Start Ramp Rate (%/sec) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 4110 | – | – | – | – | – | – | – | – | – |
| 2010 | 3990 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2015 | 3890 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2020 | 3790 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2025 | 3690 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2030 | 3590 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2035 | 3490 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2040 | 3390 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2045 | 3290 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |
| 2050 | 3190 | 59 | 25.2 | 0.75 | 2.00 | 0.55 | 6 | 0 | 20 | 20 |

The capital cost breakdown for the battery energy storage plant is shown in Figure 19.

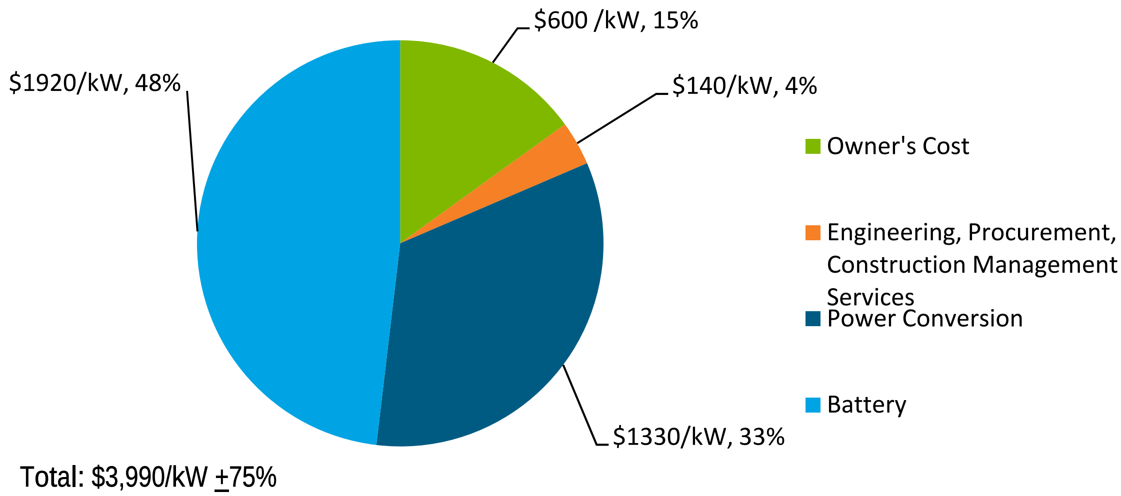


**Figure 19. Capital Cost Breakdown for a Battery Energy Storage Plant**

Battery energy storage plant cost reductions will occur primarily in the battery cost category over time.

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# Appendix A. Energy Estimate for Wave Energy Technologies

## RESOURCE ESTIMATE

This appendix documents an analysis of the wave energy resource in the United States and provides the basis for information presented in Section 0 above.

### Coastline of the United States

Using Google Earth, Black & Veatch sketched a rough outline of the East and West Coasts of the United States, and divided each into coastal segments to match the available wave data, as described in Figure A-1 and Table A-1. The states of Alaska and Hawaii were not included.

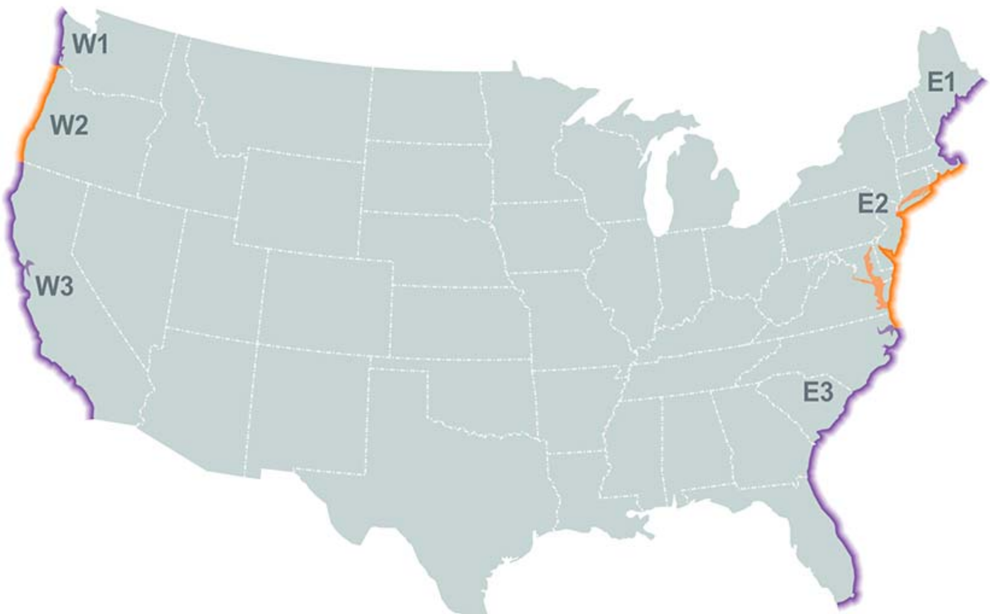



**Figure A-1. Designated Coastal Segments**

W1: Neah Bay, WA (26.5 kW/m @ ? m)
W2: Coquille, OR (21.2 kW/m @ 64 m)
W3: San Francisco, CA (20 kW/m @ 52 m)
E1: Portland, ME(4.9 kW/m @ 19 m)
E2: Middle (13.8 kW/m @ 74 m)
E3: South East ( kW/m @ m)

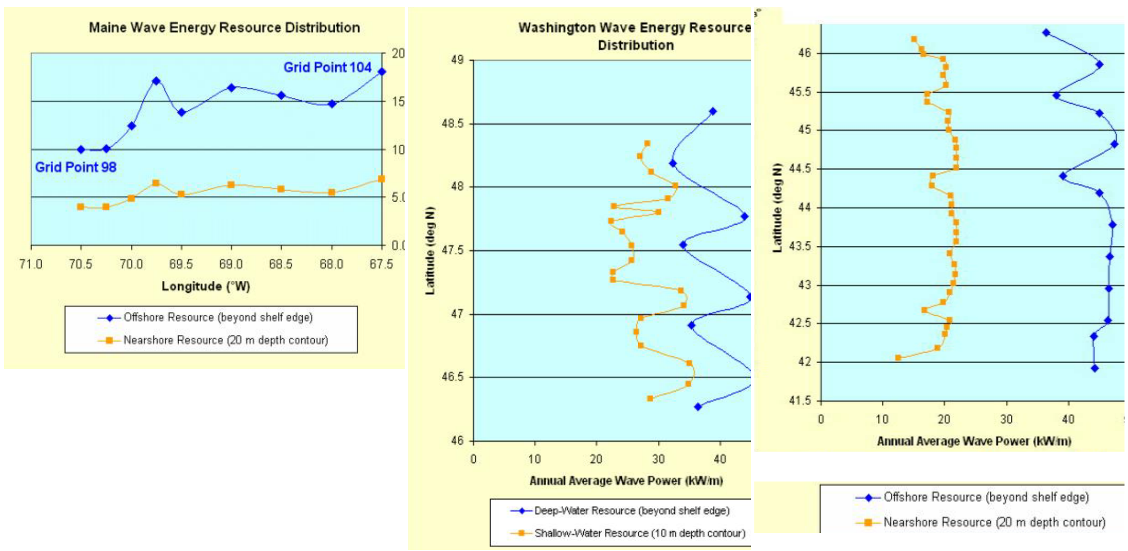
**Table A-1. Length of Coastlines in United States**

| Coastal Segment | Coastline Length (km) | Description |
|---|---|---|
| W1 | 238 | Washington |
| W2 | 492 | Oregon |
| W3 | 1322 | California |
| **West Total** | **2052** | |
| E1 | 465 | Maine–Massachusetts |
| E2 | 942 | Massachusetts–North Carolina |
| E3 | 1390 | North Carolina–Florida |
| **East Total** | **2797** | |

## Wave Energy Resource

Wave energy resource data for West Coast sites (Washington, Oregon, and California) and northern East Coast sites (Maine and Massachusetts) were extracted from several relevant reports (EPRI n.d.).

In addition to data from a small number of specific buoys, EPRI (n.d.) contained annual average power for sites along the coasts of selected states, as shown on Figure A-2. These data were used to estimate the wave energy resource for the contiguous United States.




| Maine (E1) (Hagerman et al. 2004a) | Washington (W1) (Hagerman et al. 2004b) | Oregon (W2) (Hagerman et al. 2004c) |
|---|---|---|

**Figure A-2. Wave Flux for Maine, Washington, and Oregon**

In addition to the EPRI data, wave flux results (in kW/m), from Kane (2005, Table 8) were also used to estimate California's wave energy resource as shown in Figure A-3. Most sites assessed in Kane are deeper than 100 m, but approximately 3 of the 10 sites are from shallower buoys, including Del Norte (60 m), Mendocino (82 m), and Santa Cruz (13 m, 60-80 m).

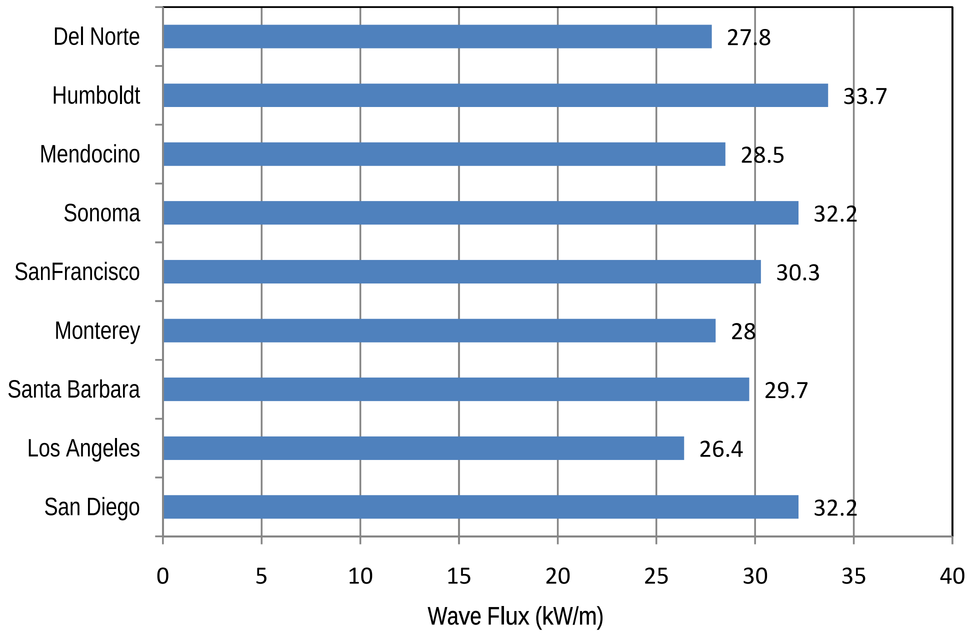



**Figure A-3. Wave Flux for California**

(Coastal segment W3, Figure A-1) (Kane 2005, Table 8)

The available data were used to estimate an average wave energy resource for each coastal segment. As a spot check, the EPRI (n.d.) cites 20 kW/m wave flux at 52-m depth at the San Francisco site, which approximately matches the 30 kW/m cited by Kane (2005, Table 8) for San Francisco at a deep site. Consequently, both studies were used with relative confidence. No wave resource data were found for the central (E2, Figure A-1) and southern (E3) East Coast.

## Normalizing to 50-m Depth

All wave resources were normalized to a 50-m depth contour. This depth is believed to represent for the next 10 years the average depth targeted by most wave energy developers, and is the basis for the cost estimates presented below. Within the next 50 years, exploiting the wave energy resource at greater depths will likely be possible. While more energy may be available at deeper sites, it might not be as commercially exploitable, as the wave direction would be more variable and grid connection costs would increase significantly.

The wave energy data presented above are sourced from deep water off the continental shelf. Results from a study by Queen's University Belfast & RPS Group (Folley et al. 2009) were used to estimate the resource at 50-m depth. Using wave data and modeling for the European Marine Energy Centre (EMEC) site in Scotland, Folley et al. calculated the gross (omni-directional), net (directionally resolved), and exploitable (net power less than four times the mean power density) for a number of site depths. Figure A-4 shows the results from this study.

Given the lack of other available data, Black & Veatch assumed the EMEC results apply to the United States and used them to estimate gross power at 50-m depth from U.S. offshore wave data from the previously mentioned sources (taken to be offshore – all directions). By multiplying the U.S. offshore data by 23.5/41 (as read from Figure A-4), the wave flux was normalized to 50-m depth.

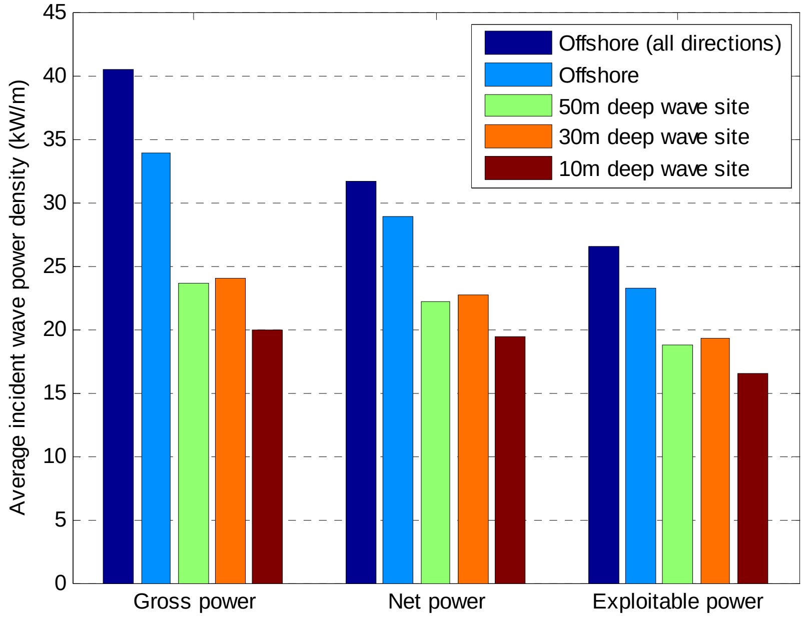



**Figure A-4. Gross v. Exploitable Power at Varying Sea Depths**

(Folley et al. 2009, p. 7)

However, the particular site conditions at the EMEC site might mean these conclusions are not applicable to all sites. Local bathymetry can create high and low resource areas, and the seabed slope is relatively steep at the EMEC site, which reduces the distance between deep and shallow sites and the energy dissipated between them. It is, for example, clear from Figure A-2 that the wave energy resource dissipation from offshore to near shore is much higher in Oregon than it is in Washington.

Additional studies are needed to establish the validity of this relationship for the U.S. coastline, but it is believed to be a reasonable first estimate.

## Directionality

Black & Veatch was not able to locate directional wave data for U.S. sites; a directionality of 0.9, which has historically been used for UK wave energy sites, was therefore assumed for the *Base Case*.

A *Pessimistic Scenario* (low-deployment) and an *Optimistic Scenario* (high deployment) were developed to reflect the uncertainty in the U.S. wave resource. In the *Pessimistic Scenario* and the *Optimistic Scenario*, factors of 0.8 and 1.0 respectively were applied to reflect the fact that at some sites the wave resource is more focused than at others (particularly in shallower waters) and that some wave devices are able to cope with directionality more efficiently than others (e.g., point absorbers).

## Spacing

The spacing between the devices was not considered in the estimate of the wave energy resource, as the resource study is based on available wave energy per wave front. Hence, no farm configuration was considered for the wave devices, and energy available is based only on a percentage of extraction from the available resource.

### Conversion from Absorbed Power to Electrical Power

A wave energy converter efficiency of 70% from the absorbed power to the electrical power generated at shore was generally assumed, as 70% is the typical value used for wave devices. In the *Pessimistic Scenario*, efficiency of 60% is assumed and 80% is assumed in the *Optimistic Scenario*.

### Exploitable Coastline

In the *Base Case*, 50% of the coastline length was estimated to be exploitable. In the *Optimistic Scenario*, the full length of coastline was considered exploitable, reflecting the fact that if a site would not be suitable for development at 50 m in the next few years, it might be exploitable at deeper or shallower waters in the next 50 years. Under the *Pessimistic Scenario,* 25% of the coastline was considered exploitable.

### Extractable Energy from the Wave Resource

Clearly, the whole energy resource cannot be extracted from the wave front without impacting the environment and the project economics. Black & Veatch did not consider environmental issues and set the criteria for extractable wave energy on the economical cut-off point. As a wave energy project is believed to be uneconomical for wave resource lower than a 15 kW/m threshold, the percentage of extractable power compared to the available resource was set to ensure the available wave resource does not drop below this economic threshold.

### Wave Energy Regime

The wave resource was classified into wave energy regimes as shown in Table A-2.

**Table A-2. Wave Energy Regime Classification**

| Wave Energy Regime | Wave Flux at 50-m Depth (kW/m) |
|---|---|
| Very Low | < 15 |
| Low | 15–20 |
| Medium | 20–25 |
| High | > 25 |

The wave energy resource (in kW/m) data were reviewed for each site, and a split in the resource was estimated (Table A-3). For example, because approximately 10 of the 13 data points for the W2 (Oregon) coastline have a wave energy resource above 25 kW/m, 75% of the resource was estimated as high," with the remainder being estimated as "medium."

**Table A-3. Wave Energy Regime Split**

| | Very Low | Low | Medium | High |
|---|---|---|---|---|
| **W1** | – | – | 100% | 0% |
| **W2** | – | – | 25% | 75% |
| **W3** | – | 100% | – | – |
| **E1** | 100% | – | – | – |
| **E2** | 100% | – | – | – |
| **E3** | 100% | – | – | – |

Coastal segment E1 (Figure A-1), with a peak average offshore wave energy resource of less than 20 kW/m, corresponding to an equivalent wave energy resource of less than 11 kW/m at 50 m, was classified as "very low" and was not counted in the wave resource estimate. Coastal segments E2 and E3 were both assumed to have a milder wave regime than E1, and therefore to also fall into the "very low" category and were not included in the resource estimate.

## Wave Energy Mean Annual Resource

By multiplying the average wave energy resource (at 50 m depth) for each segment by the coastal length, and the wave energy regime split (Table ATable -3), the U.S. wave energy resource was estimated for the Base Case as shown in Table A-4. This estimate does not construe any device capacity factors but does take into account the directionality, efficiencies, and exploitable percentage explained above. The values are given in MW, and hence they represent mean annual electrical power.

**Table A-4. Mean Annual U.S. Wave Energy Resource (MW)—*Base Case***

| Coastal Segment | Low | Medium | High | Total |
|---|---|---|---|---|
| W1 | – | 707 | – | 707 |
| W2 | – | 476 | 1,429 | 1,905 |
| W3 | 1,539 | – | – | 1,539 |
| **West Total** | 1,500 | 1,200 | 1,400 | 4,100 |
| **East Total** | – | – | – | – |
| **TOTAL** | 1,500 | 1,200 | 1,400 | 4,100 |

As explained above, the mean annual U.S. wave energy resource for the *Pessimistic* and *Optimistic Scenarios* are shown in Table A-5 and Table A-6 respectively, consistent with the directionality, the spacing, and the percentage of coastline exploitable assumptions for these Scenarios described above.

**Table A-5. Mean Annual U.S. Wave Energy Resource (MW)—*Pessimistic Scenario***

| Coastal Segment | Low | Medium | High | Total |
|---|---|---|---|---|
| W1 | – | 269 | – | 269 |
| W2 | – | 181 | 544 | 726 |
| W3 | 586 | – | – | 586 |
| **West Total** | 600 | 500 | 500 | 1,600 |
| **East Total** | – | – | – | – |
| **TOTAL** | 600 | 500 | 500 | 1,600 |

**Table A-6. Mean Annual U.S. Wave Energy Resource (MW)—*Optimistic Scenario***

| Coastal Segment | Low | Medium | High | Total |
|---|---|---|---|---|
| W1 | – | 1,795 | – | 1,795 |
| W2 | – | 1,210 | 3,629 | 4,838 |
| W3 | 3,908 | – | – | 3,908 |
| **West Total** | 3,900 | 3,000 | 3,600 | 10,500 |
| **East Total** | – | – | – | – |
| **TOTAL** | 3,900 | 3,000 | 3,600 | 10,500 |

## Capacity Factor

The U.S. wave resource is smaller than the UK resource. Black & Veatch based its cost estimates on UK-based technologies designed mostly for UK sites. The rated power and power matrix that is being used in this cost estimate was developed for an average UK site of approximately 30 kW/m, which is higher than for any U.S. site. Typically, technology developers would change the rated power conditions and tuning of their device to match a lower power resource site, however, in this analysis the technologies have not been optimized for the different site conditions.

Table A-7 shows the capacity factors that were applied in the cost estimates for the different resource bands. As explained above, these are lower than they would be if the device were optimized specifically for a U.S. site rather than for a UK site, but this is not expected to make a significant difference to the results, bearing in mind the other potential uncertainties in the analysis.

**Table A-7. Capacity Factors for the Different Resource Bands in the United States**

| Resource Band | Representative Site | Capacity Factor |
|---|---|---|
| Low (15 kW/m –20 kW/m) | Massachusetts | 15% |
| Medium (20 kW/m–25 kW/m) | Oregon | 20% |
| High (25 kW/m–30 kW/m) | UK | 25% |

## Installed Capacity Limits in the United States

The values in Tables A-4 to A-6 are annual average power generation as they were calculated from the annual wave energy resource available from the wave front. To estimate the corresponding installed capacity, the values stated above were divided by the capacity factors given in Table A-7. Clearly, major uncertainties are inherent to the wave resource in the United States, and hence the total wave energy resource ranges from 9,000 MW to 55,000 MW electrical installed capacity (including efficiencies), as shown in Table A-8 and Figure A-5.

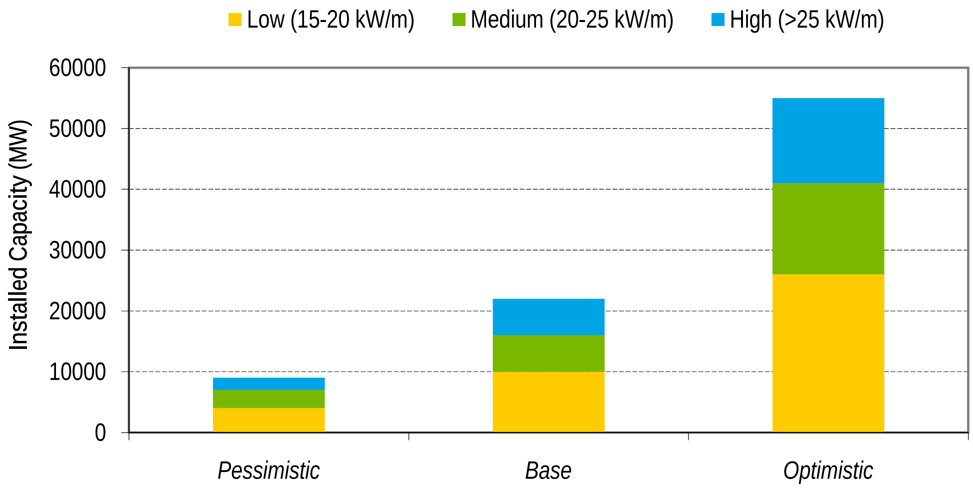



Figure A-5

**Table A-8. U.S. Wave Energy Resource (MW)—Installed Capacity Summary for all Scenarios**

| Scenario | Low Band (15-20 kW/m) | Medium Band (20-25 kW/m) | High Band (>25 kW/m) | Total |
|---|---|---|---|---|
| *Pessimistic* | 4,000 | 3,000 | 2,000 | 9,000 |
| *Base Case* | 10,000 | 6,000 | 6,000 | 22,000 |
| *Optimistic* | 26,000 | 15,000 | 14,000 | 55,000 |

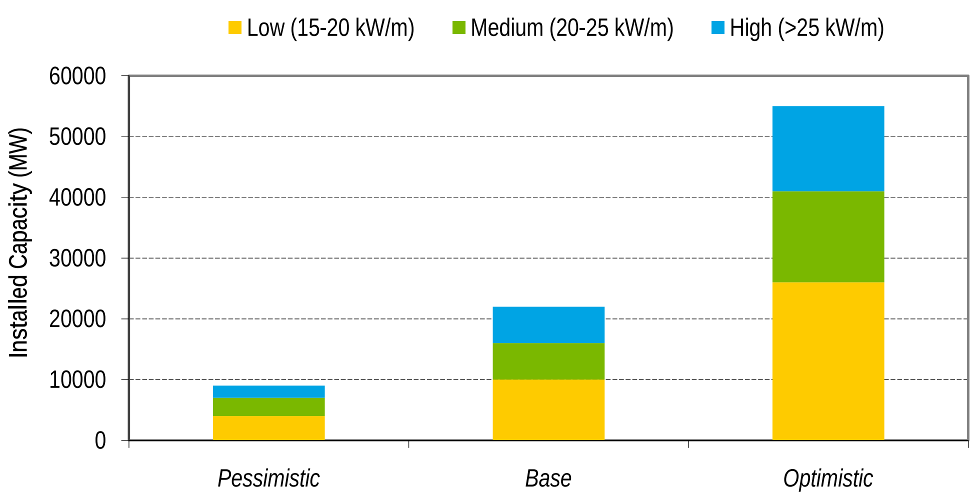



**Figure A-5. Wave resource estimate for different scenarios**

# COST OF ENERGY ESTIMATE

To forecast the future cost of energy of wave power in the United States, a number of key assumptions must be made. Initially, a deployment scenario must be generated to forecast the potential growth of the industry; a starting cost of energy must be determined based on the current market costs; and, a learning rate or curve is required to reflect potential reductions in the cost of energy with time. This section details Black & Veatch's methods to determine a future forecast of the potential economics of the wave power industry in the United States.

Given the relative uncertainties due to the early stage of the wave power market, an *Optimistic Scenario*, a *Base Case*, and a *Pessimistic Scenario* were considered for the deployment rates, cost of electricity, and learning rates. The *Base Case* represents Black & Veatch's most likely estimate, while the *Optimistic* and *Pessimistic Scenarios* represent the potential range of the primary uncertainties in the analysis.

## Wave Deployment Estimate

### Global Deployment

Global deployment is required to drive the learning rate of a technology; therefore, Black & Veatch developed an assumption for the deployment of wave energy converters globally to 2050. This estimate was made identifying the planned short term (to 2030) future deployments of the leading wave energy converter technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

### Deployment in the United States

Deployment in the United States has been based on the growth rate of global deployment. The current installed capacity and the planned installed capacity for 2010 in the United States were calculated. These starting values were then used in combination with the global growth rate to determine the scenarios for U.S. deployment to 2050. The growth rates for the *Optimistic Scenario*, the *Base Case*, and the *Pessimistic Scenario* were based on 25% of high, 16% of base, and 8% of low global deployment scenarios respectively and therefore each was assigned a unique growth rate. The total resource installed capacities estimates for the scenarios calculated above were applied. Figure A-6 shows the results of the analysis.

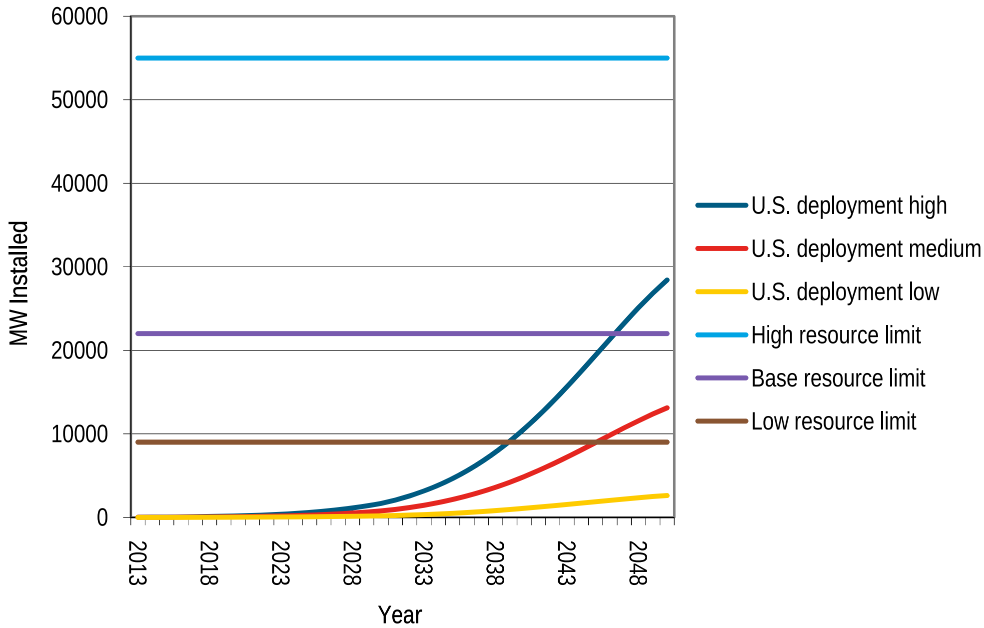



**Figure A-6. Deployment Scenarios for Wave Power in the United States to 2050**

The analysis shows that the United States could install to approximately13 gigawatt (GW) by 2050 in the *Base Case* with an *Optimistic* deployment scenario of approximately 28.5 GW; the *Pessimistic* deployment scenario installed 2.5 GW by 2050; none of the scenarios reaches its respective deployment limit. The growth rates vary among the deployment scenarios; these different rates are the major contributing factor to the large variance among the scenarios and reflect the current lack of understanding of the U.S. resource and the early stage of development of the wave energy converter industry.

## Deployment Assumption

Given the relatively low energy density of U.S. wave resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future. This order of exploitation is a key assumption used throughout the cost modelling and will naturally result, as seen below, in distinct offsets in cost of electricity projections at the points of transition between the resource bands.

## Deployment Constraints

The deployment growth is limited only by the resource constraints. It was assumed that all other factors impacting deployment would be addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and supporting grid infrastructure.

## Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for wave technology, and considers scenarios for future generation costs. Figure A-7 shows learning rate data for a range of emerging renewable energy technologies.

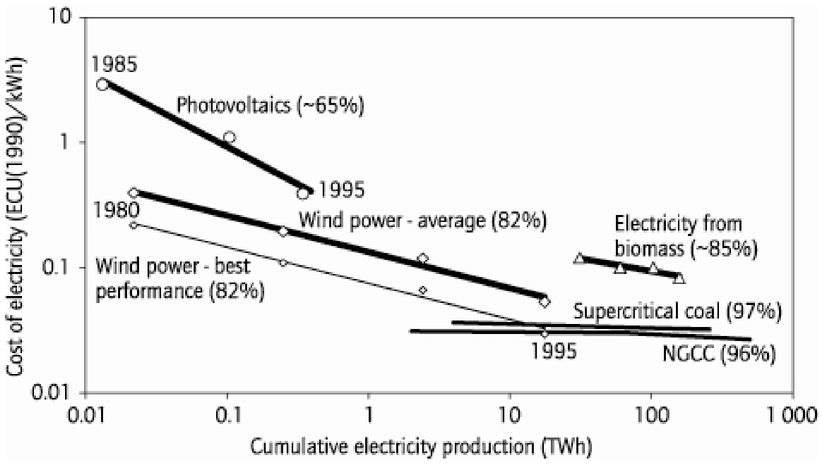



**Figure A-7. Learning in Renewable Energy Technologies**

(IEA 2000)

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics during 1985–1995 was approximately 65% (learning rate approximately 35%), and the progress ratio for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that may be experienced in the wave energy industry will be subjective. The closest analogy for the wave industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the wave industry for the following reasons:

- In wind, much of the learning was a result of doing "the same thing bigger" or "upsizing" rather than "doing the same or something new." This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.[6] Most wave energy devices (particularly resonant devices) do not work in this way. A certain size of device is required for a particular location to minimize the energy cost, and simply making larger devices does not reduce energy costs in the same way. Nevertheless, wave devices can benefit from the economies of scales of building farms with larger devices and larger numbers of devices.

[6] See, for example, Coulomb and Neuhoff 2006, which calculates an 11% learning rate for wind excluding learning due to "upsizing."

- Unlike wind in which the market as mostly adopted a single technical solution (3-bladed horizontal-axis turbine), there are many different technology options for wave energy devices and there is little indication at this stage as to which technology is the best solution. This indicates that learning rate reductions will take longer to realize when measured against cumulative industry capacity.

The learning rates for wave energy converters have been developed as per the above discussion and are presented in Table A-9. The learning rates for the United States were assumed to be 1% less than what would be expected in the UK, as the energy densities of the perspective sites are lower (which suggests that there may be less room for cost improvement).

**Table A-9. Learning Rates**

| Scenario | Learning Rate |
|---|---|
| *Optimistic* | 15% |
| *Base Case* | 11.5% |
| *Pessimistic* | 8% |

## Cost of Energy

### Cost Input Data

Black & Veatch used its experience in the wave energy converter industry to develop a cost of electricity for a first 10-MW farm assuming 50 MW installed globally, which effectively represents the cost of the initial commercial farm; these costs are presented in Table A-10. The costs presented are considered an industry average covering both off-shore and near-shore wave technologies. Learning rates were applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

**Table A-10. Cost Estimate for a 10-MW Wave Farm after Installation of 50 MW**

| Resource | Costs | Costs ($ million) | | Performance (%) | | Cost of Electricity(c/kWh) |
|---|---|---|---|---|---|---|
| | | Capital | Operating (annual) | Capacity Factor | Availability | |
| High-band Resource (25-30 kW/m) | *Pessimistic* | 73 | 4.6 | 23% | 88% | 69 |
| | *Base Case* | 62 | 3.9 | 25% | 92% | 50 |
| | *Optimistic* | 50 | 3.4 | 28% | 95% | 37 |
| Medium-band Resource (20-25 kW/m) | *Pessimistic* | 77 | 4.8 | 18% | 88% | 91 |
| | *Base Case* | 66 | 4.1 | 20% | 92% | 67 |
| | *Optimistic* | 53 | 3.5 | 22% | 95% | 49 |
| Low-band Resource (15-20 kW/m) | *Pessimistic* | 81 | 5.0 | 14% | 88% | 127 |
| | *Base Case* | 68 | 4.4 | 15% | 92% | 94 |
| | *Optimistic* | 56 | 3.8 | 17% | 95% | 69 |

The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

## General Assumptions

These general assumptions were used for this analysis:

- Project life: 20 years
- Discount rate: 8%.
- Device availability: 90% in the Base Case, 92% in the *Optimistic Scenario*, and 88% in the *Pessimistic Scenario*.

Also, the cost of electricity presented is in 2008 dollars and future inflation has not been accounted for.

## Cost of Energy

The cost of electricity directly depends on the learning curve and the deployment rate. Figure A-8 shows the cost of electricity forecast for the *Base Case* learning rate and the *Base Case* deployment scenario (Table A-9 and Figure A-6 respectively) based on the *Optimistic, Base Case*, and *Pessimistic* costs (Table A-8). The *Optimistic* and *Pessimistic* curves in the figure represent the upper and lower cost uncertainty bands for the *Base Case* deployment assumption and learning rate.

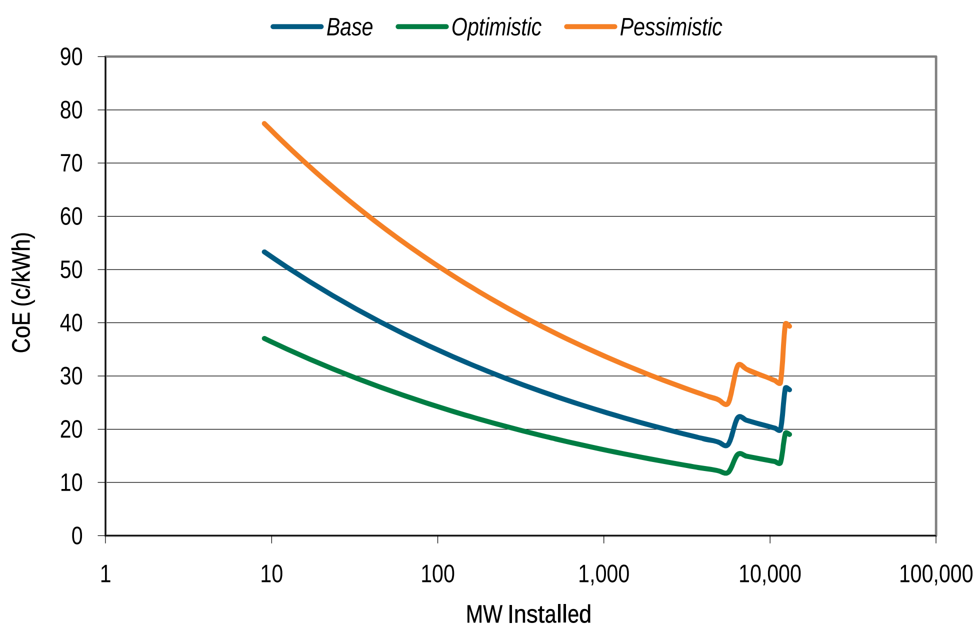



**Figure A-8. Cost of energy projection with installed capacity for *Base Case* deployment and learning rates**

The *Base Case* cost of energy falls to 17c/kWh after approximately 5.5GW is installed however, the cost of electricity then increases as the best sites have been exploited and is 27c/kWh after 13GW is installed (2050). The two spikes in the graph show the effect of moving from the high-band resource to the medium- band resource and from the medium-band to the low- band resource.

Figure A-9 shows the *Optimistic* deployment scenario and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. These assumptions have a considerable effect on the cost of electricity, with the *Optimistic* cost of electricity reducing to a low point of approximately 8c/kWh (*Base Case* 12c/kWh) after approximately 14 GW is installed before rising as the high-band resource is exhausted and the medium-band resource is used; the cost of electricity then falls to approximately 9c/kWh (*Base Case* 13c/kWh) after 28.5 GW is installed. Sufficient resource is considered to be available so that the low-band resource is not required by 2050.

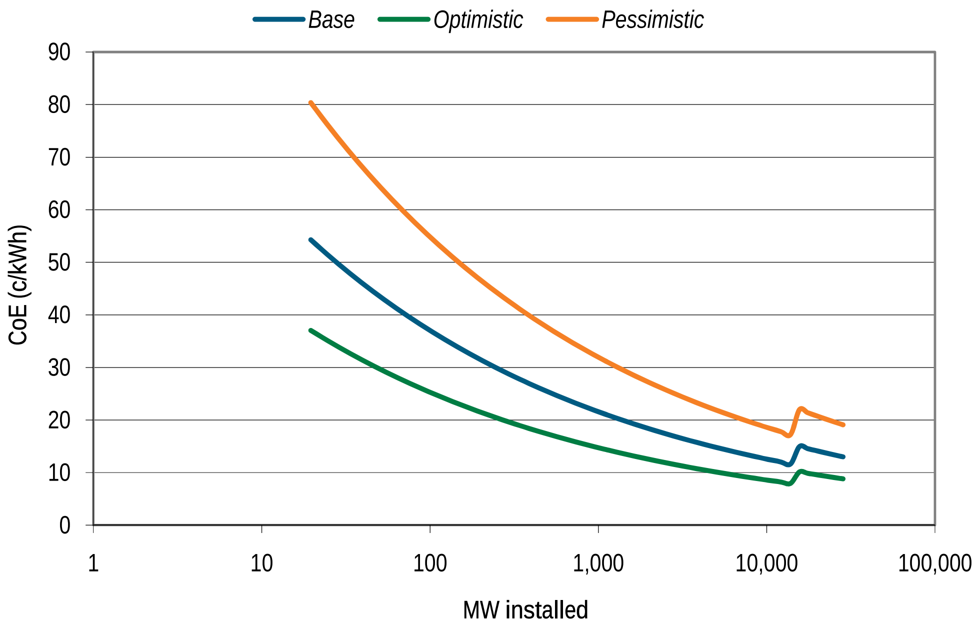



**Figure A-9. Cost of energy (projection with installed capacity for *Optimistic* deployment and learning rates**

Figure A-10 shows the *Pessimistic* deployment and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. In this scenario, there are no high-band resource sites; therefore, the analysis starts from the medium-band resource before moving to the low-band resource. The *Pessimistic* cost of electricity falls to a low point of approximately 34c/kWh (*Base Case* 24c/kWh) after approximately 2GW is installed; the installations then require the low-band resource where the cost of electricity finishes on 42c/kWh (*Base Case* 31c/kWh) after 2.5GW is installed.

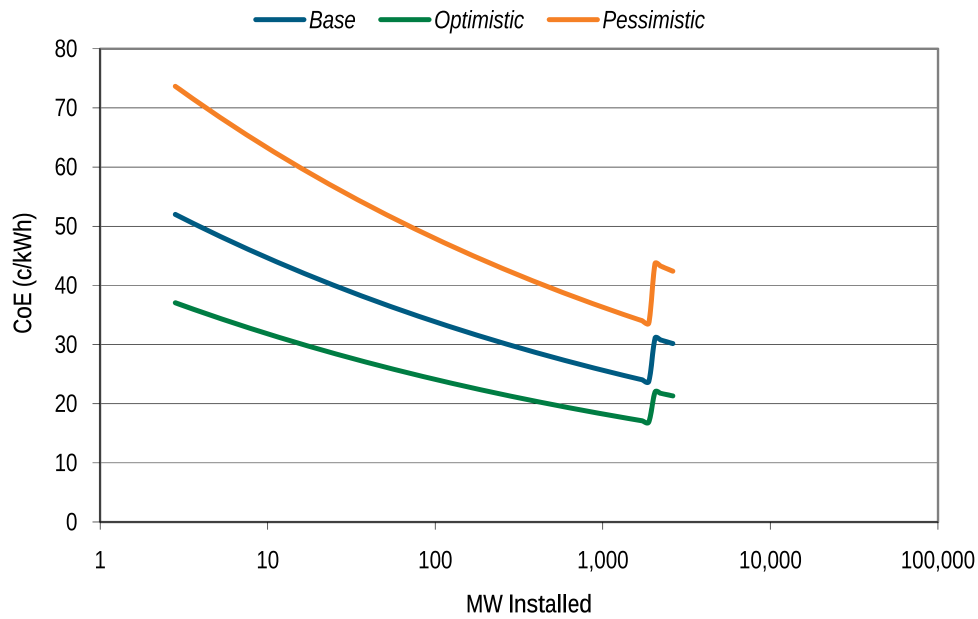



**Figure A-10. Cost of energy (c/kWh) over projection with installed capacity for *Pessimistic* deployment and learning rates**

## Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic*, and *Pessimistic Scenarios* and the *Base Case* operating expenditure costs to 2050 are shown in Table A-11. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource; in Table A-11, the costs highlighted in green, orange, and red correspond to a high, medium and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table A-11 relate directly to the costs projected in Figure A-8; the *Base Case* overnight costs were taken from the *Base Case* (middle) curve in Figure A-8; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure A-9); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure A-10).

**Table A-11. Capital and Operating Costs to 2050**

| Year | *Base Case* Capacity Factor (%) | *Base Case* Overnight Cost ($/kW) | *Optimistic* Overnight Cost —High Deployment/ Learning Rate | *Pessimistic* Overnight Cost —Low Deployment/ Learning Rate | *Base Case* Fixed O&M ($/kW-Yr) | Construction Schedule (Months) | Planned Outage Rate (%) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|
| 2008 | | | | | | | | |
| 2010 | 25% | 14,579 | 11,400 | 18,482 | 741 | 24 | 1% | 7% |
| 2015 | 25% | 9,336 | 6,252 | 13,558 | 474 | 24 | 1% | 7% |
| 2020 | 25% | 7,030 | 4,283 | 11,308 | 357 | 24 | 1% | 7% |
| 2025 | 25% | 5,756 | 3,282 | 9,886 | 292 | 24 | 1% | 7% |
| 2030 | 25% | 4,782 | 2,564 | 8,714 | 243 | 24 | 1% | 7% |
| 2035 | 25% | 3,989 | 2,015 | 7,746 | 203 | 24 | 1% | 7% |
| 2040 | 25% | 3,451 | 1,662 | 7,059 | 175 | 24 | 1% | 7% |
| 2045 | 20% | 4,094 | 1,888 | 6,603 | 208 | 24 | 1% | 7% |
| 2050 | 15% | 5,379 | 1,727 | 8,318 | 273 | 24 | 1% | 7% |

The data for the *Base Case* and *Optimistic Scenarios*— which assume the same (*Base Case*) cost of electricity starting point in 2015, along with the estimated cumulative installed capacity in the United States—are also presented in Table A-12. The following results are taken from the mid cases of the *Base Case* and *Optimistic Scenarios*).

**Table A-12. Capital and Operating Costs to 2050 (Same Starting Costs—Middle Cases)**

| | *Base Case* | | | *Optimistic Scenario* | | |
|---|---|---|---|---|---|---|
| Year | MW Installed (in U.S.) | *Base Case* Overnight Cost ($/kW) | *Base Case* Fixed O&M ($/kW-yr) | MW Installed (in U.S.) | *Base Case* Overnight Cost ($/kW) | *Base Case* Fixed O&M ($/kW) |
| 2008 | – | – | – | – | – | – |
| 2010 | – | – | – | – | – | – |
| 2015 | 5 | 9,336 | 474 | 11 | 9,336 | 474 |
| 2020 | 19 | 7,030 | 357 | 41 | 6,397 | 325 |
| 2025 | 37 | 5,756 | 292 | 80 | 4,902 | 249 |
| 2030 | 140 | 4,782 | 243 | 304 | 3,830 | 195 |
| 2035 | 371 | 3,989 | 203 | 804 | 3,009 | 153 |
| 2040 | 670 | 3,451 | 175 | 1,452 | 2,482 | 126 |
| 2045 | 881 | 4,039 | 205 | 1,910 | 2,804 | 142 |
| 2050 | 735 | 5,379 | 273 | 1,592 | 2,565 | 130 |

## Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The greatest uncertainty for resource estimates stems from the fact that the available data is located mostly in very deep regions that would not be suitable for installation of wave energy devices. As a consequence, the data were extrapolated to shallower regions. This major uncertainty for the West Coast resource could be reduced by using hydrodynamic models to estimate the wave energy resource at different depths[7]. The total lack of data for the middle (E2, Figure A-1) and lower (E3) East Coast of the United States also adds uncertainty to the resource and cost estimates. However, because the wave energy resource is believed to be relatively small in these regions, the U.S. resource assessment could be improved by investigating the remaining areas (E1, Figure A-2) to confirm that the wave energy resource is not significant on the East Coast.

The cost data provided in this report were based on Black & Veatch's experience working with leading wave technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable estimate of future costs; however, the industry is still in its infancy; and therefore these costs are in the main estimates. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore subject to significant uncertainty. Deployment will ultimately be driven by numerous variables, including financing, grid constraints, government policy, and the strength of the supply chain.

## Summary

The deployment analysis indicates that approximately 12.5 GW of wave generation could be installed in the United States by 2050 in the *Base Case* with approximately 27 GW by 2050 under an Optimistic (high-deployment) scenario, and 2.5 GW by 2050 under a Pessimistic (low-deployment) scenario. None of the scenarios reach their respective resource ceilings.

The cost of electricity analysis estimates a 17c/kWh cost of electricity for *Base Case* assumptions after approximately 5GW is installed (2050 *Base Case* installed capacity); after approximately 13 GW is installed the cost of electricity is 27c/kWh. In the *Optimistic Scenario* (deployment rate, learning rate, and costs)), the cost of electricity is estimated to be as low as 9c/kWh after approximately 28.5GW is installed (2050). In the *Pessimistic Scenario*, the cost of electricity after approximately 2.5GW is installed (2050) is estimated at 42c/kWh.

[7] Not only the mean wave power (kW/m) must be assessed, but the yearly wave occurrence data to produce Hs/Te scatter diagrams must also be assessed, as these are crucial to apply to device performance to estimate capacity factors.

# Appendix B. Energy Estimate for Tidal Stream Technologies

This appendix documents an analysis of the tidal energy resource in the United States and provides the basis for information presented in Section 0 above.

## RESOURCE ESTIMATE

### Raw Resource Assessment

Black & Veatch sourced tidal stream energy data from existing EPRI tidal stream energy literature (EPRI n.d.) for West Coast sites (Washington and California) and northern East Coast sites (Maine and Massachusetts). The results are summarized in Table B-1 for the contiguous United States.

**Table B-1. Raw Resource Assessment Summary**

| State | Site | Depth (m) | Mean Annualised Power Density ($kW/m^2$) | Cross-section Area ($m^2$) | Mean Annualised Available Power (MW) |
|---|---|---|---|---|---|
| Massachusetts | Blynman Canal | 2 | 0.93 | 18.2 | 0.02 |
| | Muskeget Channel | 25 | 0.95 | 14000 | 13.3 |
| | Woods Hole Passage | 4 | 1.32 | 350 | 0.5 |
| | Cape Cod Canal | 11 | 2.11 | 1620 | 3.4 |
| | Lubec Narrows | 6 | 5.5 | 750 | 4.1 |
| Maine | Western Passage | 55 to 75 | 2.2 | 16300 | 35.9 |
| | Outer Cobscook Bay | 18 to 36 | 1.64 | 14500 | 23.8 |
| | Bagaduce Narrows | 3 in Narrow 18 to 24 off Castine | 1.94 | 400 | 0.8 |
| | Penobscot River | 18 to 21 | 0.73 | 5000 | 3.7 |
| | Kennebec River entrance | 9 to 20 | 0.44 | 990 | 0.4 |
| | Piscataqua River | 10 to 14 | 1.48 | 2300 | 3.4 |
| Washington | Washington | 42 | 1.7 | 62600 | 106.4 |
| California | California | 90 | 3.2 | 74100 | 237.1 |

The sites highlighted in Table B-1 were retained after considering depth and resource constraints. Only sites of depth greater than approximately 20 m and power density greater than 1 $kW/m^2$ were believed to be suitable for commercial tidal stream energy extraction. In any case, the sites not highlighted have a negligible contribution to the total)

Based on an understanding that EPRI focused its research on the most promising states, no other data than that from EPRI were reviewed and therefore the potential tidal stream resource for other locations was not assessed directly. . A cursory investigation of the U.S. coastline revealed other potentially suitable sites such as Long Island Sound, Chesapeake Bay, and Rhode Island. Assumptions about the total U.S. potential are discussed in the resource limits section below.

To estimate the amount of energy that might be actually produced from tidal energy converters (TECs), three significant impact factor (SIF)[8] values were applied to all sites corresponding to the three different scenarios as follows: 10% SIF was applied to the *Pessimistic Scenario*, 20% SIF to the *Base Case*, and 50% to the *Optimistic Scenario*. The extractable power results are summarized in Table B-2.

**Table B-2. Extractable Resource Assessment Summary**

| State | Sites | Extractable Power (MW) | | |
|---|---|---|---|---|
| | | *Pessimistic Scenario* | *Base Case* | *Optimistic Scenario* |
| Massachusetts | Muskeget Channel | 1 | 3 | 7 |
| Maine | Western Passage | 4 | 7 | 18 |
| | Outer Cobscook Bay | 2 | 5 | 12 |
| Washington | Washington | 11 | 21 | 53 |
| California | California | 24 | 47 | 119 |
| Total | | 42 | 83 | 208 |

The total extractable resource varies from approximately 40 MW to 200 MW (approximately 80 MW for the *Base Case*).

## Resource Limits

To account for yet to be discovered sites, a coefficient was applied to the three total values obtained in the raw resource assessment section above. The results are shown in Table B-3.

**Table B-3. Estimated Resource Limits**

| | Extractable Power (MW) | | |
|---|---|---|---|
| | *Pessimistic Scenario* | *Base Case* | *Optimistic Scenario* |
| Total | 42 | 83 | 208 |
| Multiplier | 1 | 2 | 10 |
| Grand Total | 42 | 167 | 2082 |

[8] In 2004 and 2005, as part of the UK Marine Energy Challenge (MEC), Black & Veatch defined a "significant impact factor" (SIF) to estimate the tidal resource extractable in the United Kingdom, representing the percentage of the total resource at a site that could be extracted without significant economic, environmental, or ecological effects.

As there are significant uncertainties associated with the resource data associated with these estimates, and it is possible that the mean annualized power density and resource in the California and Washington sites might have been over-estimated in the EPRI studies, a factor of one was applied on the resource in the *Pessimistic Scenario*. In the *Base Case* and *Optimistic Scenario*, this possibility of overstatement of the potential of know sites was assumed to be significantly smaller than the potential of undiscovered sites; <u>a factor of 2 was assumed in the *Base Case* and a factor of 10was applied in the *Optimistic Scenario*.</u> Based on these assumptions, the total estimated resource for the contiguous United States. is close to the total estimated UK resource.

To derive estimates of the cost of tidal stream energy, the sites were split into three categories based on their raw power density: 3% of the sites identified earlier present a power density of less than 1.5 $kW/m^2$, 57% present a power density greater than 2.5 $kW/m^2$, and the remaining present a power density comprised between 1.5 $kW/m^2$ and 2.5 $kW/m^2$. Given the small number of sites, the factors applied to account for undiscovered sites, and Black & Veatch's experience, these figures were modified to be consistent with a more likely distribution, as shown in Table B-4.

**Table B-4. Resource Bands**

| Resource | Proportion of Total Extractable Resource |
|---|---|
| % Low-band resource (<1.5kW/m2) | 10% |
| % Medium-band resource (>1.5kW/m2 ; <2.5kW/m2) | 50% |
| % High-band resource (>2.5kW/m2) | 40% |

## COST OF ENERGY ESTIMATE

### Tidal Stream Deployment Estimate

### Global and U.S. Deployments

Global deployment is required to drive the learning rate of a technology. An assumption was developed for the deployment of TECs globally to 2050. This estimate was made by identifying the planned short term (to 2030) future deployments of the leading TEC technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

Deployment of commercial tidal farms in the United States was assumed to be a certain percentage of the growth rate of this global deployment projection (Table B-4), consistent with the total resource ceilings identified above.

**Table B-4. U.S. Contribution to Global Tidal Stream Deployment**

| Scenario | Proportion of World Deployment |
|---|---|
| *Optimistic* | 30% |
| *Base Case* | 20% |
| *Pessimistic* | 10% |

For the *Base Case*, the first 10-MW farm was estimated to be installed after approximately 50 MW had been installed worldwide. The different deployments scenarios obtained are shown in Figure B-1.

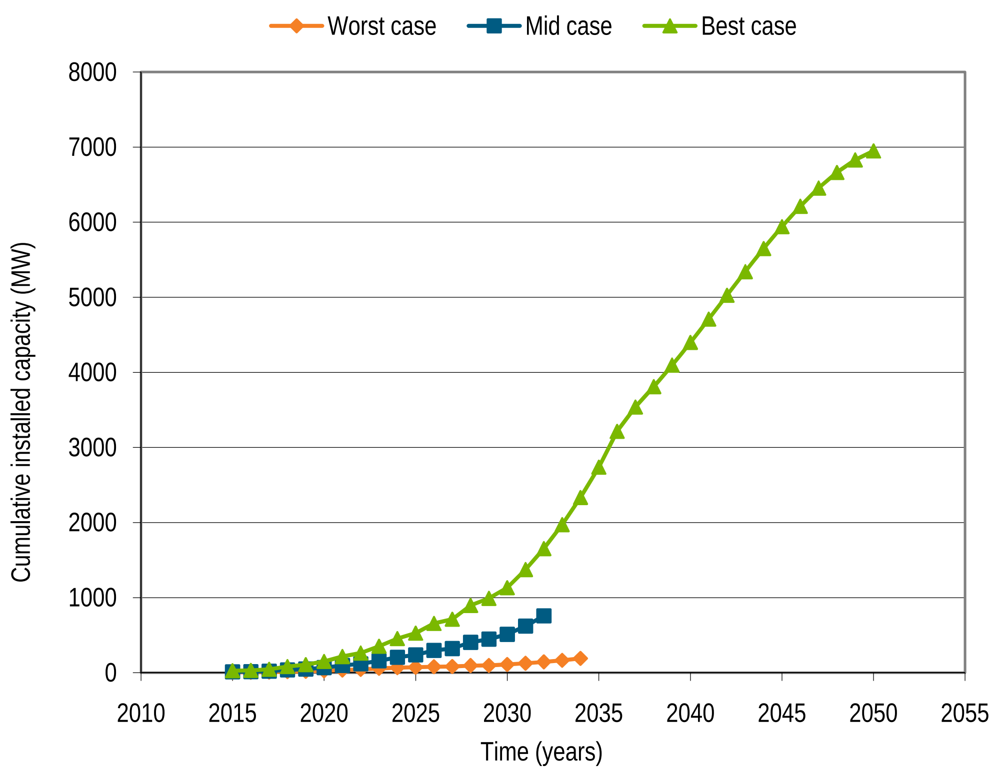



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**Figure B-1. Deployment scenarios for tidal stream power (continental waters) in the United States to 2050**

In the *Base Case* and *Pessimistic Scenario* cases, the resource ceilings were reached between 2030 and 2035, whereas in the *Optimistic Scenario* the resource ceiling was not reached even in 2050.

## Deployment Assumptions

Given the relatively low energy density of U.S. tidal resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future.

## Deployment Constraints

The deployment growth is only limited by the resource constraints. It was assumed that all other factors impacting deployment are addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and grid infrastructure.

### Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for tidal stream technology, and considers scenarios for future generation costs. Figure A-7 (Appendix A) shows learning rate data for a range of emerging renewable energy technologies.

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics over the period 1985 to 1995 was approximately 65% (learning rate approximately 35%) and that for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that might be experienced by the tidal stream industry will be subjective. The closest analogy for the tidal stream industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the tidal stream industry for the following reasons:

- In the wind power industry, much of the learning was a result of doing “the same thing bigger” or “upsizing” rather than “doing the same or something new.” This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.9 Tidal turbines, like wind turbines, will benefit from increasing rotor swept areas until the maximum length of the blades, limited by loadings, is reached. However, unlike for wind power, the ultimate physical limit on rotor diameter can also be imposed by cavitation or limited water depth, the latter being particularly important for the relatively shallow sites of (25–35 m) that are likely to be developed in the near-term.
- Much of the learning in wind power occurred at small scale with small-scale units (<100 kW), often by individuals with very low budgets. Tidal stream on the other hand requires large investments to deploy prototypes and therefore requires a smaller number of more risky steps to develop, which tends to suggest that the learning will be slower (and the progress will be ratio higher).
- Tidal stream technology development is still in its infancy, and learning rates are often higher during this period of technology development, offsetting the points in (2).

[9] See, for example, http://www.electricitypolicy.org.uk/pubs/wp/eprg0601.pdf, which calculates an 11% learning rate for wind excluding learning due to ‘upsizing’.

The likely range of learning rates for the tidal energy industry in the United States is believed to be between 7% and15% (progress ratios of 85%–93 %) with a mid range value of 11%.

## Cost of Energy

An in-house techno-economic model was used by Black & Veatch to derive A cost of electricity was developed for a first 10-MW farm installed in the three-band resource environment discussed in the resource limits section above, assuming this installation occurred after 50 MW of capacity had been installed worldwide. The cost of electricity presented is considered an industry average for horizontal-axis axial-flow turbines. The learning rate range specified above was used to derive the future cost of electricity.

## General Assumptions

As described above, the resource data used in the techno-economic analysis were sourced from EPRI (n.d.). The three resource cases were modelled and derived from the Muskeget Channel site (approximately 1 $kW/m^2$) and from the sites in Washington and California (respectively approximately 2 $kW/m^2$ and 3 $kW/m^2$). The current velocity distributions from the real sites were slightly modified to exactly match the generic resource mid-bands (1 $kW/m^2$, 2 $kW/m^2$, and 3 $kW/m^2$). These general assumptions were used for this analysis:

- Depth: 40 m for all three generic sites considered
- Project life: 25 years
- Discount rate: 8%.
- Device availability: 92.5% in the Base Case, 95% in the *Optimistic Scenario*, and 90% in the *Pessimistic Scenario*.

The cost of electricity presented is in 2009 dollars and future inflation has not been accounted for. The exchange rate used to convert any costs from GBP to USD was: 1 GBP = 1.65 USD.

## Cost Results

The estimated cost of electricity is presented in Table B-5. Learning rates were only applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

**Table B-5. Cost Estimate for a 10-MW Tidal Farm after Installation of 50 MW**

| Resource | Costs | Costs ($ million) | | Performance (%) | | Cost of Electricity (c/kWh) |
|---|---|---|---|---|---|---|
| | | Capital | Operating (annual) | Capacity Factor | Availability | |
| *High-band Resource* | *Pessimistic* | 69 | 2.5 | 22% | 90.0% | 45.0 |
| | Base Case | 59 | 2.0 | 26% | 92.5% | 35.8 |
| | *Optimistic* | 54 | 1.5 | 30% | 95.0% | 29.3 |
| *Medium-band Resource* | *Pessimistic* | 74 | 2.6 | 19% | 90.0% | 55.0 |
| | Base Case | 63 | 2.1 | 23% | 92.5% | 44.4 |
| | *Optimistic* | 58 | 1.6 | 26% | 95.0% | 35.9 |
| *Low-band Resource* | *Pessimistic* | 127 | 4.3 | 21% | 90.0% | 84.3 |
| | Base Case | 104 | 3.5 | 25% | 92.5% | 66.9 |
| | *Optimistic* | 96 | 2.6 | 29% | 95.0% | 55.0 |

Black & Veatch's techno-economic model is run in such a way that the technology (rated power of the devices) matches the resource, hence the range of capacity factors obtained in Table B-5. The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

The supply curves obtained after applying the learning rates to the cost of electricity from Table B-5 are shown in Figures B-2, B-3, and B-4.

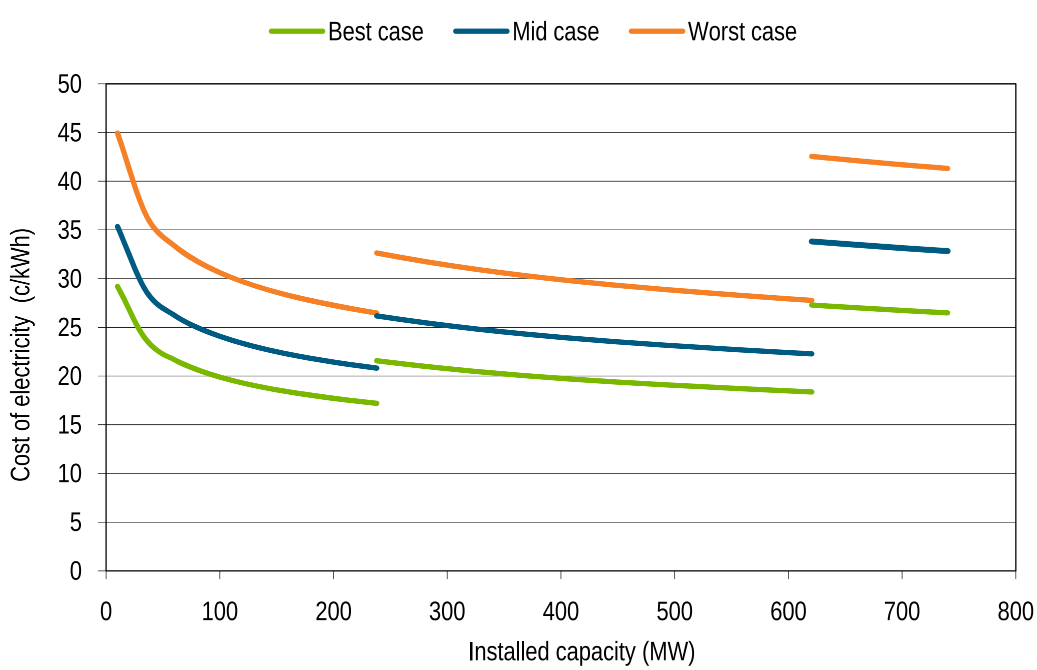



**Figure B-2. Supply curve for a *Base Case* resource ceiling and an 11% learning rate**

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 20c/kWh after approximately 250 MW were installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these additional 350 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity lies slightly above the previous 20c/kWh level. The late exploitation of the low-band resource brought the cost of electricity back to the original levels (approximately 35c/kWh in the *Base Case*).

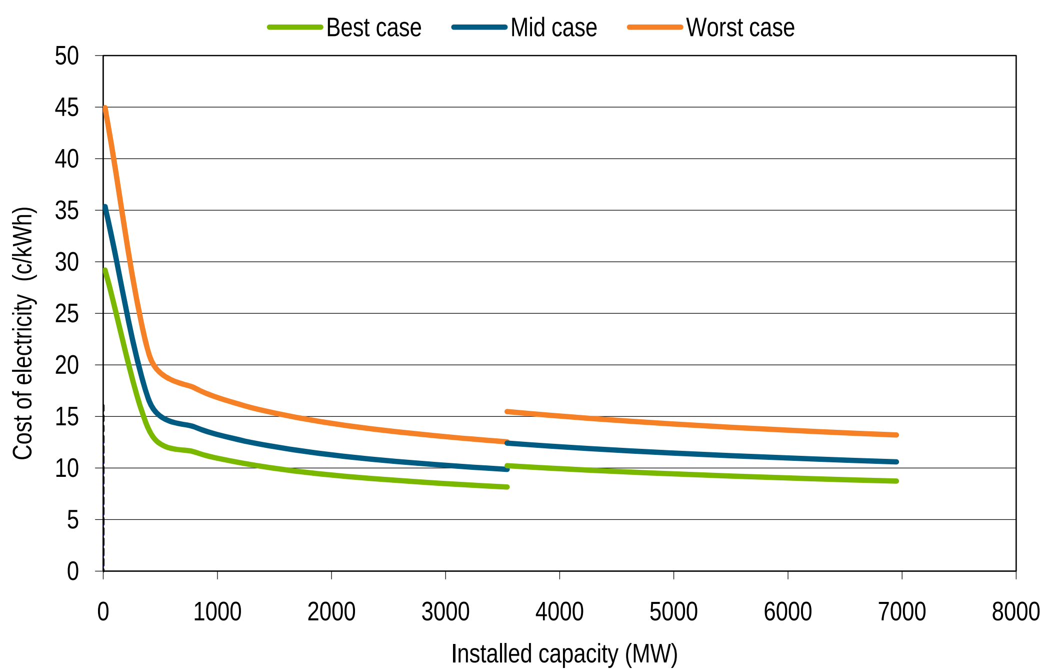



**Figure B-3. Supply curve for an *Optimistic* resource ceiling and a 15% learning rate**

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 10c/kWh after approximately 3,500 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 3,500 MW of medium resource sites had been exploited, the *Base Case* cost of electricity was back at the previous 10c/kWh level.

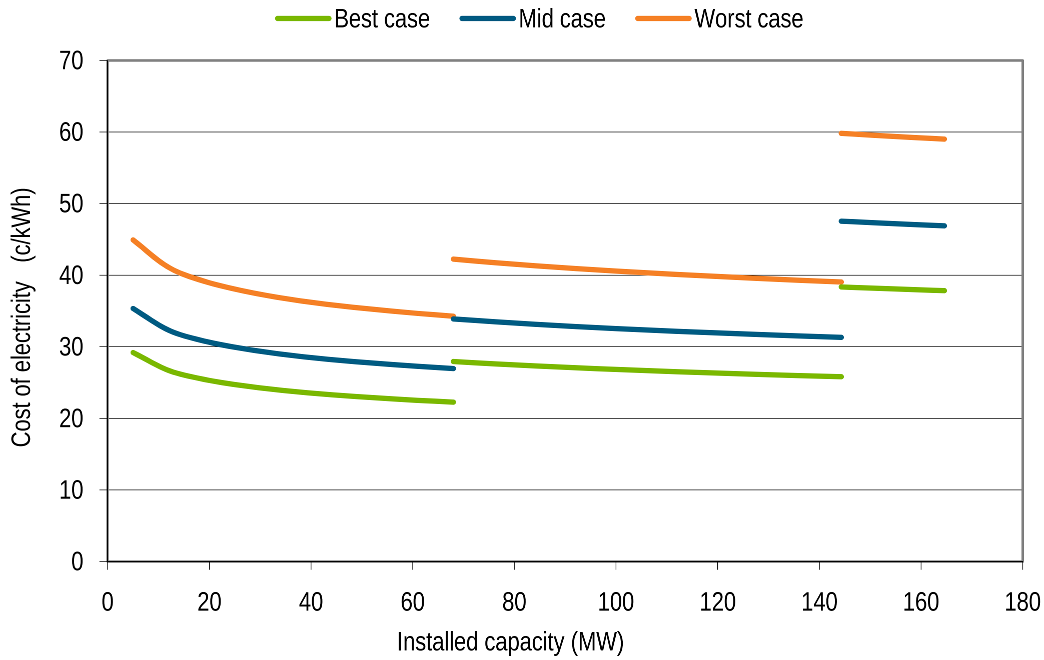



**Figure B-4. Supply curve for a *Pessimistic* resource ceiling and a 7% learning rate**

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 27c/kWh after approximately 70 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 90 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity reaches approximately 30c/kWh level. The late exploitation of the low-band resource took the cost of electricity to the highest levels reached in this analysis (approximately 48c/kWh in the *Base Case*).

## Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic* and *Pessimistic Scenarios* and the *Base Case* operating costs to 2050 are shown in Table B-6. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource. In Table B-6, the costs highlighted in green, orange, and red correspond to a high, medium, and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table B-6 relate directly to the costs projected in Figures B-2 through B-4. The *Base Case* overnight costs were taken from the *Base Case (*middle curve) of Figure B-2; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure B-3); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure B-4). In Table B-6, in the base and high overnight cost scenarios, the low-band resource sites were exploited between 2030 and 2035 and hence no red colored cells are visible.

**Table B-6. Capital and Operating Costs to 2050**

| Year | *Base Case* Capacity Factor | *Base Case* Overnight Cost ($/KW) | *Optimistic* Overnight Cost—High Deployment/ Learning Rate ($/KW) | *Pessimistic* Overnight Cost—Low Deployment/ Learning Rate ($/KW) | *Base Case* Variable O&M ($/MWh) | *Base Case* Fixed O&M $/KW-Yr | Heat Rate (Btu/KWh) | Construction Schedule (Months) | Planned Outage Rate (%) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | - | - | - | - | - | - | - | - | - | - |
| 2010 | - | - | - | - | - | - | - | - | - | - |
| 2015 | 26% | 5,940 | 5,445 | 6,930 | - | 198 | - | 24 | 1% | 6.5% |
| 2020 | 26% | 4,401 | 3,293 | 5,843 | - | 147 | - | 24 | 1% | 6.5% |
| 2025 | 26% | 3,498 | 2,524 | 5,661 | - | 117 | - | 24 | 1% | 6.5% |
| 2030 | 23% | 3,267 | 1,962 | 5,381 | - | 112 | - | 24 | 1% | 6.5% |
| 2035 | | - | 1,611 | - | - | - | - | 24 | 1% | 6.5% |
| 2040 | | - | 1,540 | - | - | - | - | 24 | 1% | 6.5% |
| 2045 | | - | 1,434 | - | - | - | - | 24 | 1% | 6.5% |
| 2050 | | - | 1,376 | - | - | - | - | 24 | 1% | 6.5% |

The data for the *Base Case* and *Optimistic Scenario* are also presented in Table B-7 with the same starting points, along with the estimated cumulative installed capacity in the United States. The following results were taken from the middle cases of the *Base Case* and *Optimistic Scenario* (Figures B-2 and B-3).

**Table B-7. Capital Expenditure Cost and Operating Expenditure Costs to 2050 (Same Starting Costs—Middle Cases)**

| *Base Case* | | | | *Optimistic Scenario* | | | |
|---|---|---|---|---|---|---|---|
| Year | MW Installed (in U.S.) | *Base Case* Overnight Cost ($/kW) | *Base Case* Fixed O&M ($/kW-Yr) | Year | MW Installed (in U.S.) | *Base Case* Overnight Cost ($/kW) | *Base Case* Fixed O&M ($/kW-Yr) |
| 2008 | | | | 2008 | | | |
| 2010 | | | | 2010 | | | |
| 2015 | 10 | 5,940 | 198 | 2015 | 15 | 5,940 | 198 |
| 2020 | 61 | 4,401 | 147 | 2020 | 131 | 3,591 | 120 |
| 2025 | 238 | 3,498 | 117 | 2025 | 407 | 2,753 | 92 |
| 2030 | 493 | 3,267 | 112 | 2030 | 1,190 | 2,140 | 71 |
| 2035 | - | - | - | 2035 | 2,756 | 1,758 | 59 |
| 2040 | - | - | - | 2040 | 4,297 | 1,672 | 57 |
| 2045 | - | - | - | 2045 | 5,813 | 1,557 | 53 |
| 2050 | - | - | - | 2050 | 6,950 | 1,494 | 51 |

## Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The U.S. resource assessment could be improved by investigating the remaining coastline that has not yet been investigated and by using hydrodynamic modeling on the most promising sites.

The cost data provided in this report were based on Black & Veatch's experience working with leading tidal stream technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable current estimate of future costs; however, the industry is still in its infancy and therefore these costs are in the main estimates.. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore are subject to significant uncertainty. Deployment will ultimately be driven by numerous variables including financing, grid constraints, government policy, and the strength of the supply chain.

## Summary

The analysis estimates a 20c/kWh cost of electricity for *Base Case* assumptions after 250 MW is installed; after 720 MW is installed (*Base Case* total resource ceiling), the cost of electricity is estimated to be 34c/kWh due to the late exploitation of the low-band resource. In the *Optimistic Scenario* (deployment rate, learning rate, and costs), the cost of electricity is estimated to be as low as 10c/kWh after 7 GW is installed (2050 resource level). In the *Pessimistic Scenario,* the cost of electricity after 180 MW is installed (*Pessimistic* Scenario total resource ceiling) is estimated at 48c/kWh.

The cost of tidal stream energy extraction in the United States cannot be further investigated until a full national resource assessment is completed.

# Appendix C. Breakdown of Cost for Solar Energy Technologies

This appendix documents capital cost breakdowns for both photovoltaic and concentrating solar power technologies, and provides the basis for information presented in Sections 0 above.

## SOLAR PHOTOVOLTAICS

Figure C-1 and Table C-1 show capital cost ($/W) projection for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC), assuming no owner's costs and no extra margin. Table C-2 breaks these costs down by component.

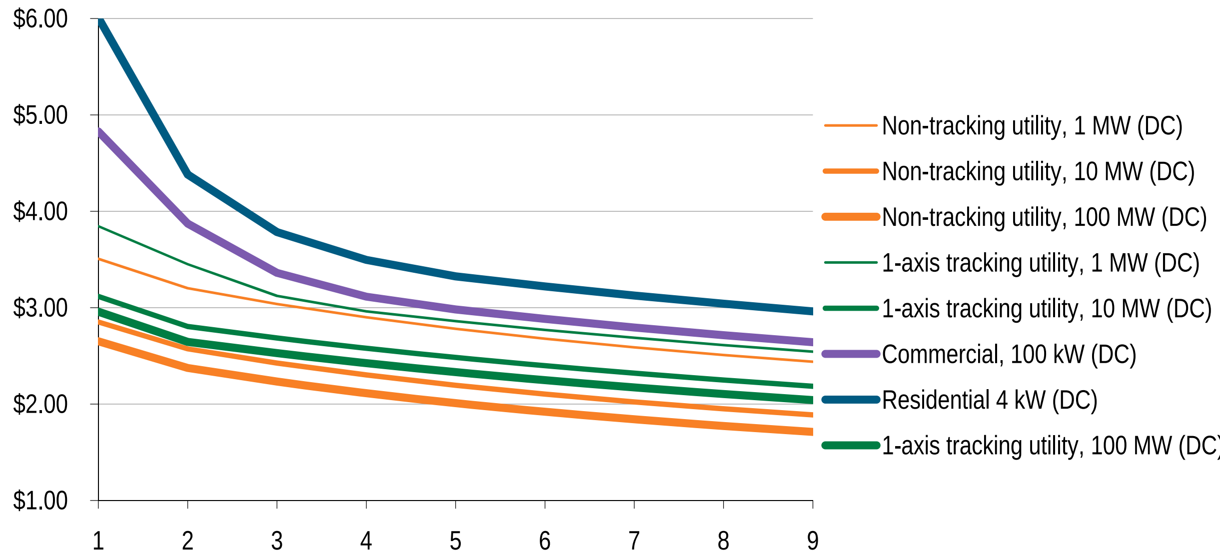



**Figure C-1. Capital cost projection for solar photovoltaic technology**

**Table C-1. Solar Photovoltaics Capital Costs ($/W) by Type and Size of Installation**

| | Utility PV Non-Tracking | | | Utility PV 1-Axis Tracking | | | Commercial PV | Residential PV |
|---|---|---|---|---|---|---|---|---|
| | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 100 kW (DC) | 4 kW (DC) |
| 2010 | $3.19 | $2.59 | $2.41 | $3.50 | $2.83 | $2.69 | $4.39 | $5.72 |
| 2015 | $2.91 | $2.34 | $2.16 | $3.14 | $2.55 | $2.40 | $3.52 | $4.17 |
| 2020 | $2.76 | $2.21 | $2.03 | $2.84 | $2.44 | $2.30 | $3.06 | $3.60 |
| 2025 | $2.64 | $2.09 | $1.92 | $2.69 | $2.34 | $2.20 | $2.83 | $3.33 |
| 2030 | $2.53 | $2.00 | $1.83 | $2.60 | $2.26 | $2.12 | $2.71 | $3.17 |
| 2035 | $2.43 | $1.91 | $1.75 | $2.52 | $2.18 | $2.04 | $2.62 | $3.07 |
| 2040 | $2.35 | $1.84 | $1.67 | $2.44 | $2.11 | $1.98 | $2.54 | $2.98 |
| 2045 | $2.28 | $1.77 | $1.61 | $2.37 | $2.05 | $1.91 | $2.47 | $2.90 |
| 2050 | $2.22 | $1.72 | $1.56 | $2.31 | $1.99 | $1.86 | $2.40 | $2.82 |

**Table C-2. Solar Photovoltaics Capital Cost ($/W) Breakdown by Type and Size of Installation—No Owner's Costs, No Extra Margin**

| | Non-Tracking Utility | | 1-Axis tracking Utility | | Commercial | | Residential | |
|---|---|---|---|---|---|---|---|---|
| **Year** | **1 MW (DC)** | **10 MW (DC)** | **100 MW (DC)** | **1 MW (DC)** | **10 MW (DC)** | **100 MW (DC)** | **100 kW (DC)** | **4 kW (DC)** |
| 2010 | $3.19 | $2.59 | $2.41 | $3.50 | $2.83 | $2.69 | $4.39 | $5.72 |
| 2015 | $2.91 | $2.34 | $2.16 | $3.14 | $2.55 | $2.40 | $3.52 | $4.17 |
| 2020 | $2.76 | $2.21 | $2.03 | $2.84 | $2.44 | $2.30 | $3.06 | $3.60 |
| 2025 | $2.64 | $2.09 | $1.92 | $2.69 | $2.34 | $2.20 | $2.83 | $3.33 |
| 2030 | $2.53 | $2.00 | $1.83 | $2.60 | $2.26 | $2.12 | $2.71 | $3.17 |
| 2035 | $2.43 | $1.91 | $1.75 | $2.52 | $2.18 | $2.04 | $2.62 | $3.07 |
| 2040 | $2.35 | $1.84 | $1.67 | $2.44 | $2.11 | $1.98 | $2.54 | $2.98 |
| 2045 | $2.28 | $1.77 | $1.61 | $2.37 | $2.05 | $1.91 | $2.47 | $2.90 |
| 2050 | $2.22 | $1.72 | $1.56 | $2.31 | $1.99 | $1.86 | $2.40 | $2.82 |
| **2010** | | | | | | | | |
| Overnight EPC | **$3.19** | **$2.59** | **$2.41** | **$3.50** | **$2.83** | **$2.69** | **$4.39** | **$5.72** |
| Modules | $1.68 | $1.47 | $1.42 | $2.20 | $1.80 | $1.75 | $2.33 | $3.00 |
| Balance of system (BOS) | $0.73 | $0.51 | $0.49 | $0.56 | $0.49 | $0.49 | $0.66 | $0.76 |
| Labor, engineering, and construction | $0.67 | $0.51 | $0.40 | $0.65 | $0.47 | $0.38 | $1.27 | $1.77 |
| Shipping | $0.10 | $0.10 | $0.10 | $0.08 | $0.06 | $0.06 | $0.13 | $0.19 |
| Module efficiency | 9.5% | 9.5% | 9.5% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| Ground coverage ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |

| | Non-Tracking Utility | | 1-Axis tracking Utility | | Commercial | | Residential | |
|---|---|---|---|---|---|---|---|---|
| Year | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 100 kW (DC) | 4 kW (DC) |
| **2015** | | | | | | | | |
| Overnight EPC | **$2.91** | **$2.34** | **$2.16** | **$3.14** | **$2.55** | **$2.40** | **$3.52** | **$4.17** |
| Modules | $1.45 | $1.27 | $1.23 | $1.88 | $1.56 | $1.51 | $2.00 | $2.19 |
| BOS | $0.75 | $0.51 | $0.50 | $0.57 | $0.51 | $0.50 | $0.63 | $0.73 |
| Labor, engineering, and construction | $0.62 | $0.46 | $0.34 | $0.60 | $0.42 | $0.33 | $0.76 | $1.07 |
| Shipping | $0.09 | $0.09 | $0.09 | $0.08 | $0.06 | $0.06 | $0.12 | $0.18 |
| Module efficiency | 11.0% | 11.0% | 11.0% | 16.0% | 16.0% | 16.0% | 16.0% | 16.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2020** | | | | | | | | |
| Overnight EPC | **$2.76** | **$2.21** | **$2.03** | **$2.84** | **$2.44** | **$2.30** | **$3.06** | **$3.60** |
| Modules | $1.33 | $1.17 | $1.13 | $1.60 | $1.47 | $1.42 | $1.65 | $1.76 |
| BOS | $0.74 | $0.50 | $0.49 | $0.57 | $0.50 | $0.50 | $0.58 | $0.68 |
| Labor, engineering, and construction | $0.61 | $0.45 | $0.33 | $0.59 | $0.41 | $0.32 | $0.72 | $0.99 |
| Shipping | $0.08 | $0.08 | $0.08 | $0.08 | $0.06 | $0.06 | $0.12 | $0.17 |
| Module efficiency | 12.0% | 12.0% | 12.0% | 17.0% | 17.0% | 17.0% | 17.0% | 17.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2025** | | | | | | | | |
| Overnight EPC | **$2.64** | **$2.09** | **$1.92** | **$2.69** | **$2.34** | **$2.20** | **$2.83** | **$3.33** |
| Modules | $1.23 | $1.08 | $1.04 | $1.47 | $1.39 | $1.34 | $1.50 | $1.61 |

| | Non-Tracking Utility | | 1-Axis tracking Utility | | Commercial | | Residential | |
|---|---|---|---|---|---|---|---|---|
| Year | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 100 kW (DC) | 4 kW (DC) |
| BOS | $0.73 | $0.50 | $0.48 | $0.56 | $0.50 | $0.49 | $0.57 | $0.67 |
| Labor, engineering, and construction | $0.60 | $0.44 | $0.32 | $0.58 | $0.40 | $0.31 | $0.65 | $0.88 |
| Shipping | $0.08 | $0.08 | $0.08 | $0.07 | $0.06 | $0.06 | $0.11 | $0.16 |
| Module efficiency | 13.0% | 13.0% | 13.0% | 18.0% | 18.0% | 18.0% | 18.0% | 18.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2030** | | | | | | | | |
| Overnight EPC | **$2.53** | **$2.00** | **$1.83** | **$2.60** | **$2.26** | **$2.12** | **$2.71** | **$3.17** |
| Modules | $1.14 | $1.00 | $0.96 | $1.39 | $1.32 | $1.27 | $1.42 | $1.53 |
| BOS | $0.73 | $0.49 | $0.48 | $0.56 | $0.49 | $0.49 | $0.57 | $0.67 |
| Labor, engineering, and construction | $0.59 | $0.43 | $0.32 | $0.58 | $0.40 | $0.31 | $0.62 | $0.82 |
| Shipping | $0.07 | $0.07 | $0.07 | $0.07 | $0.05 | $0.05 | $0.10 | $0.16 |
| Module efficiency | 14.0% | 14.0% | 14.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2035** | | | | | | | | |
| Overnight EPC | **$2.43** | **$1.91** | **$1.75** | **$2.52** | **$2.18** | **$2.04** | **$2.62** | **$3.07** |
| Modules | $1.07 | $0.93 | $0.90 | $1.33 | $1.25 | $1.21 | $1.35 | $1.45 |
| BOS | $0.72 | $0.49 | $0.47 | $0.55 | $0.49 | $0.48 | $0.56 | $0.66 |
| Labor, engineering, and construction | $0.58 | $0.43 | $0.31 | $0.57 | $0.39 | $0.30 | $0.61 | $0.81 |
| Shipping | $0.07 | $0.07 | $0.07 | $0.07 | $0.05 | $0.05 | $0.10 | $0.15 |

| | Non-Tracking Utility | | 1-Axis tracking Utility | | Commercial | | Residential | |
|---|---|---|---|---|---|---|---|---|
| Year | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 100 kW (DC) | 4 kW (DC) |
| Module efficiency | 15.0% | 15.0% | 15.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2040** | | | | | | | | |
| Overnight EPC | **$2.35** | **$1.84** | **$1.67** | **$2.44** | **$2.11** | **$1.98** | **$2.54** | **$2.98** |
| Modules | $1.00 | $0.88 | $0.84 | $1.26 | $1.19 | $1.15 | $1.29 | $1.38 |
| BOS | $0.72 | $0.48 | $0.47 | $0.55 | $0.48 | $0.48 | $0.56 | $0.66 |
| Labor, engineering, and construction | $0.57 | $0.42 | $0.30 | $0.57 | $0.39 | $0.30 | $0.60 | $0.79 |
| Shipping | $0.06 | $0.06 | $0.06 | $0.06 | $0.05 | $0.05 | $0.10 | $0.14 |
| Module efficiency | 16.0% | 16.0% | 16.0% | 21.0% | 21.0% | 21.0% | 21.0% | 21.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |
| **2045** | | | | | | | | |
| Overnight EPC | **$2.28** | **$1.77** | **$1.61** | **$2.37** | **$2.05** | **$1.91** | **$2.47** | **$2.90** |
| Modules | $0.94 | $0.82 | $0.79 | $1.20 | $1.14 | $1.10 | $1.23 | $1.32 |
| BOS | $0.71 | $0.48 | $0.46 | $0.55 | $0.48 | $0.47 | $0.55 | $0.66 |
| Labor, engineering, and construction | $0.57 | $0.41 | $0.30 | $0.56 | $0.38 | $0.29 | $0.60 | $0.79 |
| Shipping | $0.06 | $0.06 | $0.06 | $0.06 | $0.05 | $0.05 | $0.09 | $0.14 |
| Module efficiency | 17.0% | 17.0% | 17.0% | 22.0% | 22.0% | 22.0% | 22.0% | 22.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |

| | Non-Tracking Utility | | 1-Axis tracking Utility | | Commercial | | Residential | |
|---|---|---|---|---|---|---|---|---|
| Year | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 1 MW (DC) | 10 MW (DC) | 100 MW (DC) | 100 kW (DC) | 4 kW (DC) |
| **2050** | | | | | | | | |
| Overnight EPC | **$2.22** | **$1.72** | **$1.56** | **$2.31** | **$1.99** | **$1.86** | **$2.40** | **$2.82** |
| Modules | $0.89 | $0.78 | $0.75 | $1.15 | $1.09 | $1.05 | $1.17 | $1.26 |
| BOS | $0.71 | $0.47 | $0.46 | $0.54 | $0.48 | $0.47 | $0.55 | $0.65 |
| Labor, engineering, and construction | $0.56 | $0.41 | $0.29 | $0.56 | $0.38 | $0.29 | $0.59 | $0.78 |
| Shipping | $0.06 | $0.06 | $0.06 | $0.06 | $0.04 | $0.04 | $0.09 | $0.13 |
| Module efficiency | 18.0% | 18.0% | 18.0% | 23.0% | 23.0% | 23.0% | 23.0% | 23.0% |
| Ground Coverage Ratio | 43.0% | 43.0% | 43.0% | 30.0% | 30.0% | 30.0% | 50.0% | 100.0% |

## CONCENTRATING SOLAR POWER

Tables C-3 and C-6 show performance and cost for trough systems in 2010 and 2050. Tables C-4 and C-5 show performance and cost for tower systems in 2010 and 2050.

**Table C-3. Solar Trough Performance for 2010 and 2050**

| Parameter | 2010 | | 2050 | |
|---|---|---|---|---|
| | Without Storage | With Storage | Without Storage | With Storage |
| Plant size (MW) | 200 | 200 | 200 | 200 |
| Design direct normal irradiance (DNI) W/m$^2$ | 950 | 950 | 950 | 950 |
| Solar multiple | 1.4 | 2 | 1.4 | 2 |
| Storage (hours) | 0 | 6 | 0 | 6 |
| Solar to thermal efficiency | 0.6 | 0.6 | 0.65[a] | 0.65 |
| Thermal to electric efficiency | 0.37 | 0.37 | 0.37 | 0.365[b] |
| Design thermal output (MWth-hours) | 541 | 541 | 541 | 548 |
| Required aperture (m$^2$) | 1327643 | 1896633 | 1225517 | 1774721 |
| Thermal storage (MWth-hours) | 0 | 3243 | 0 | 3288 |

[a] Improved reflectivity, receiver
[b] Parallel storage penalty

**Table C-4. Solar Trough Capital Cost Breakdown for 2010 and 2050**

| Cost Assumptions | 2020 | | 2050 | |
|---|---|---|---|---|
| | Without Storage | With Storage | Without Storage | With Storage |
| Solar field ($\$/m^2$) | 300 | 300 | 195[a] | 195 |
| Heat transfer fluid (HTF) system ($/kWe) | 500 | 500 | 375[b] | 375 |
| Power block ($\$/kW_e$) | 975 | 975 | 900 | 900 |
| Storage ($\$/kWh_{th}$) | 0 | 40 | 0 | 30 |
| Contingency | 10 | 10 | 10 | 10[c] |
| Solar field and site ($) | 398,293,030 | 568,990,043 | 238,975,818 | 346,070,656 |
| HTF and power block ($) | 295,000,000 | 295,000,000 | 255,000,000 | 255,000,000 |
| Storage ($) | 0 | 129,729,730 | 0 | 97,479,452 |
| Total with contingency ($) | 762,622,333 | 1,093,091,750 | 543,373,400 | 768,406,119 |
| Direct Costs ($/kW) | 3,813 | 5,465 | 2,717 | 3,842 |
| Engineering, procurement, construction (%) | 10 | 10 | 10 | 10 |
| Owners costs (%) | 20 | 20 | 20 | 20 |
| Indirect costs (%) | 30 | 31 | 30 | 30 |
| Total Cost ($/kW) | 4,957 | 7,135 | 3,532 | 4,995 |

[a] Reduced material, installation
[b] Lower pressure drop, advanced HTF
[c] slightly higher temperature

**Table C-5. Solar Tower Plant Parameters 2010 and 2050**

| Plant Parameters | 2010 | 2050 |
|---|---|---|
| Storage (hours) | 6 | 6 |
| Capacity factor (5) | 40 | 41 |
| Collector field aperture ($m^2$) | 1147684 | 1081000[a] |
| Receiver surface area ($m^2$) | 847 | 677.6[b] |
| Plant capacity ($MW_e$) | 100 | 100 |
| Thermal storage (hours) | 6 | 6 |
| Thermal to electric efficiency | 0.425 | 0.425 |
| Tower height (m) | 228 | 228 |
| Design thermal output ($MW_{th}$) | 235 | 235 |
| Thermal storage ($kWh_{th}$) | 1411765 | 1411765 |

[a] Better reflectivity, less spillage; Better availability, less receiver heat loss
[b] Higher flux levels; better coatings

**Table C-6. Solar Tower Capital Cost Breakdown for 2010 and 2050**

| Assumption | 2010 | | 2050 | |
|---|---|---|---|---|
| Capacity factor | 40% | | 41% | |
| Heliostat field | 235 $\$/m^2$ aperture | $269,705,740 | 235 $\$/m^2$ aperture | $167,555,000 |
| Receiver | 80000 $\$/m^2$ receiver | $67,760,000 | 50000 $\$/m^2$ receiver | $33,880,000 |
| Tower | 901500<br>0.01298 $\$/m^2$ aperture | $17,387,382 | 901500<br>0.01298 $\$/m^2$ aperture | $17,387,382 |
| Power block | 950 $\$/kW_e$ | $95,000,000 | 875 $\$/kW_e$ | $87,500,000 |
| Thermal storage | 30 $\$/kWh_{th}$ | $42,352,941 | 18 $\$/kWh_{th}$ | $25,764,706 |
| Total direct costs | | $492,206,063 | | $332,087,088 |
| Total with contingency | 10% | $541,426,669 | 10% | $365,295,797 |
| Indirect costs | | | | |
| EPC | 10% | | 10% | |
| Owners | 20% | | 20% | |
| Total Direct and Indirect Costs | 30% | $704,017,098 | 30% | $474,884,535 |
| Total Cost ($/kW) | | $7,040 | | $4,749 |

# Appendix D. Technical Description of Pumped-Storage Hydroelectric Power

This appendix presents a generic technical description and characteristics of a representative 500 MW pumped-storage hydroelectric (PSH) plant that has as its primary purpose energy storage.

## DESIGN BASIS

Pumped storage is an energy storage technology that involves moving water between an upper and lower reservoir. The system is charged by pumping water from the lower reservoir to a reservoir at a higher elevation. To discharge the system's stored energy water is allowed to flow from the upper reservoir through a turbine to the lower reservoir. The overall efficiency of the system is determined by the efficiency of the equipment (pump/turbine, motor generator) as well as the hydraulic and hydrologic losses (friction and evaporation) which are incurred. Overall cycle efficiencies of 75%–80% are typical.

Most often, a pumped storage system design utilizes a unique reversible Francis pump/turbine unit that is connected to a motor/generator. Equipment costs typically account for 30%–40% of the capital cost with civil works making up the vast majority of the remaining 60%–70%.

The configuration of the pumped-storage plant used in this report is described as follows:

1. The 500-MW pumped-storage project will operate on a daily cycle with energy stored on a 12-hour cycle and generated on a 10-hour cycle. Approximately 322 cycles per year would be assumed.
2. For purposes of this evaluation, the energy storage requirement is equal to 500 MW for 10 hours or 5,000 megawatt hours of daily peaking energy.
3. The lower reservoir is assumed to exist and a site for a new upper reservoir can be found that has the appropriate characteristics.
4. For evaluation purposes, the pumping and generating head is based on the average difference in the upper and lower reservoir levels. The reality is that the heads in both pumping and generating modes will constantly fluctuate during their respective cycles. This fluctuation must be designed
5. This evaluation is based on an average net operating head (H) for both pumping and generating cycles of 800 feet.
6. The distance from the outlet of the upper reservoir to the outlet of the lower reservoir is assumed to be 2,000 feet resulting in an L/H ratio of 2.5, which is excellent by industry standards.
7. The calculated generating flow assuming a 0.82 generating efficiency is 9,000 cubic feet per second (cfs).
8. The active water storage in the reservoirs required for this flow over the 10 hours generating cycle is 7,438 acre-feet. Adding 10 percent for inactive storage yields a total reservoir storage requirement of about 8,200 acre-feet.
9. The lower reservoir is assumed to be an existing reservoir that can afford a fluctuation of 7,438 acre-feet without environmental or other fluctuation issues.

## STUDY BASIS DESCRIPTION AND COST

Based on the above project sizing criteria, the following reconnaissance-level project design and associated capital cost was estimated:

1. Assuming an upper reservoir depth of 100 feet yields a surface area of 82 acres. Using a circular reservoir construction results in a 2,132-foot diameter and a circumference of 6,700 ft. The assumed dam would be a gravity type constructed using roller-compacted concrete (RCC). Other types such as concrete-faced rock fill, concrete arch, or embankment are possible depending on site conditions. The total volume of RCC is estimated at 670,000 cubic yards (cy). At a cost of $200/cy, RCC would cost roughly $134 million. The following are other upper reservoir estimated costs:

   A. Reservoir clearing: $10 million

   B. Emergency spillways: $5 million

   C. Excavation and grout curtain: $20 million

   D. Inlet/Outlet structure and accessories: $20 million

   The total reservoir cost is roughly $189 million.

2. The tunnels from the lower reservoir to powerhouse and from powerhouse to upper reservoir would include 20-foot diameter access tunnel (assumed to be 1,000 ft long) and 2x20 foot diameter penstock and draft tube tunnels (total of 4,200 ft long). Other tunnels and shafts for ventilation and power lines would be required. About $60 million is assumed for tunneling.
3. The powerhouse would be constructed underground and be approximately 100 feet and 200 feet for a 2x250 MW pump turbine unit. The excavation of the powerhouse would cost approximately $35 million.
4. At an estimate cost of $750 per installed kW, the powerhouse structures, equipment, and balance of plant would cost about $375 million.
5. The total estimate construction cost is therefore:

   A. Upper reservoir: $189 million

   B. Tunnels: $60 million

   C. Powerhouse excavation: $35 million

   D. Powerhouse: $375 million

   Total: $659 million

6. The following additional technical assumptions have been made for this option:

   A. The site features geological formations ideal for upper reservoir and underground development.

   B. A relatively flat 82-acre site is required for the upper reservoir. A total site area, including underground rights is about 200 acres.

   C. The site is on land where no existing human-made structures exist.

   D. No offsite roads are included.

E. The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.

F. Construction power and water is assumed to be available at the site boundary.

G. No consideration was given to possible future expansion of the facilities.

H. A 345-kV generator step-up (GSU) transformer is included. Transmission lines and substations/switchyards are not included in the base plant cost estimate. An auxiliary transformer is included.

I. Provision for protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species or historical, cultural, and archaeological artifacts is not included.

J. The upper reservoir will be capable of overtopping due to accidental over-pumping. A service spillway equal to the pumping flow is assumed.

## OTHER COSTS AND CONTINGENCY

The following are potential additional costs:

1. Plant location is assumed to be where land is not of significant societal value, with a cost of $5,000 per acre or $1 million total.
2. Transmission and substation are assumed to be adjacent to the site and is a major siting factor.
3. Project management and design engineering at 5% of construction cost or $33 million.
4. Construction management and start-up support at 5% of construction cost of $33 million.
5. A contingency of $109 million (15%) is assumed.

   Total: $176 million.

Based on the total Construction Cost of $659 million and the above Other Costs and Contingency of $176 million, the total capital cost is estimated to be $835 million, or roughly 1,670 $/kW. A 20% addition for owner's costs of the type described in Text Box 1 in section 1.2 above yields a cost of 2,004 $/kW that is comparable to the other cost estimates provided.

## OPERATING AND MAINTENANCE COST

Operating and maintenance costs are dependent on the mode of operation. For hydroelectric plants, the following are the typical annual operating and maintenance costs:

1. Routine Maintenance and spare parts: $500,000
2. Personnel wages (20 total @$65,000): $1.3 million

   A. One plant manager

   B. Two administrative staff

   C. Eight operators

   D. Two maintenance supervisors

   E. Seven maintenance and craft

3. Personnel burden @ 40% of wages: $520,000

4. Staff supplies @ 5% of wages: $65,000

   Total: $2.385 million per year

Hydroelectric plants typically operate for 5-10 years without significant major repair or overhaul costs. For evaluation purposes, a major overhaul reserve available at year 10 of $100 per installed kilowatt or $50 million is assumed. When spread over a 10-year period, the annual major overhaul cost is $5 million per year.

## CONSTRUCTION SCHEDULE

A PSH project is a major civil works infrastructure project that would take many years to develop but would provide a project life that exceeds that of the other renewable technologies evaluated in this report. Project life can be expected to be at least 50 years. Many hydropower projects constructed in the early 1900s are still in service today. The development of an impound project would have the following estimated milestone schedule:

1. Permitting, design, and land acquisition: 2-4 years
2. Equipment manufacturing: 2 years
3. Construction: 3 years

   Total: 7-9 years

## OPERATING FACTORS

A hydroelectric plant can be designed to provide the following operating factors:

1. Normal start-up and shutdown time for a PSH project is less than 1-5 minutes depending on the status of the water passages. If the unit is watered to the wicket gates and plant auxiliaries are running, unit start-up time is only a function of wicket gate opening to bring the unit up to speed and synchronize.
2. A PSH unit can be tripped off instantaneously as long as the turbine is designed to operate at runaway until the wicket gates are closed. This would be an emergency case.
3. A PSH plant can load follow and provide system frequency/voltage control.
4. Pumped-storage hydroelectric plants can black-start assuming a small emergency generator is provided for unit auxiliaries and field flashing.
5. A major feature of PSH is its ability to operate as spinning or non-spinning reserve, change from pumping to generating within 20 minutes, synchronous condensing, and it can be designed to meet grid system operator certification of these benefits.

# *Appendix H*

## *Customer Attitudes & Preferences Relating to PGE's IRP*

*by Definitive Insights for PGE*

# Customer Attitudes & Preferences Relating to PGE's Integrated Resource Plan

## Relevant Insights from Residential, General Business, & Key Business Customers

*For Definitive Insights:*

**David C. Lineweber, Ph.D.**
**Sabrina Lomeu**
**John Whaley**

# This Discussion Covers Two Recent Customer Research Efforts

- **Preferences Relating to IRP Issues:**
  - Explored issues within Residential, General Business, and Key Business customers regarding their views on the resource mix they think is most appropriate to meet future energy needs.
    - This research was commissioned to strengthen PGE's understanding of Customer concerns and to provide input into the 2013 IRP process
    - This research aligns closely with similar customer research conducted in 2006.
  - Primary objective was to quantify customer support for various energy resources under consideration for inclusion in the 2013 IRP
    - Conventional Coal, Next Generation Coal, Next Generation Nuclear, Natural Gas, Renewables (Solar, Wind, Geothermal, Biomass), Energy Conservation
- **Residential Customer Attitudes And Actions Relating to Energy Efficiency**:
  - What do customers say they have done, and are doing, in this arena?
  - What more would they be willing to do, and under what circumstances?

DEFINITIVE INSIGHTS

# Methodology

- **IRP Customer Research**
  - Customers Completed Surveys Online
    - **502** Residential ; **198** General Business; and **54** Key Business Customers
    - Surveys were completed from July – September 2012
    - Respondents were incented for their participation
  - Invitation & Screening
    - Residential and General Business Customers: Screening / invitation completed via phone
    - Key Business Customers: Invited via email to complete screener / survey online

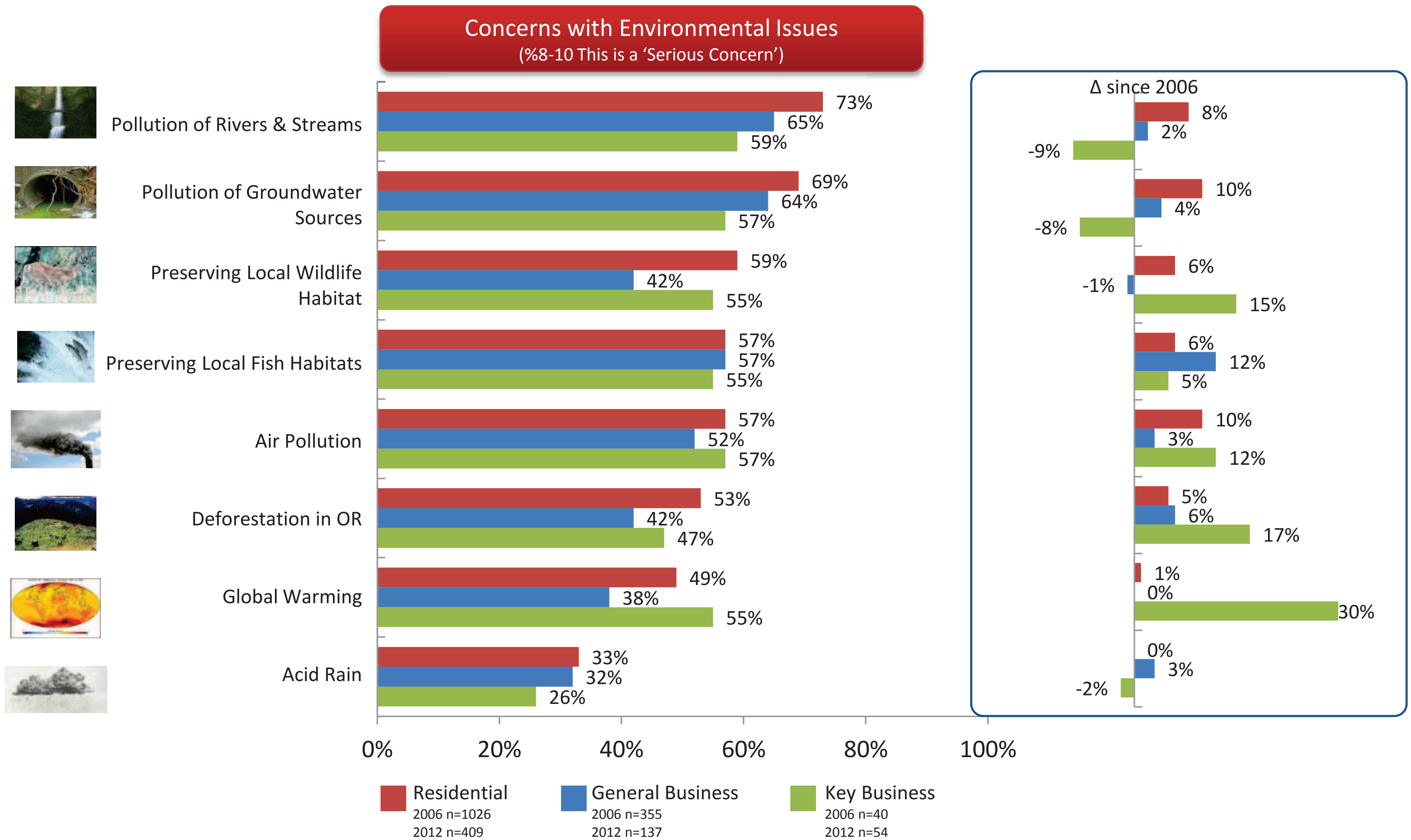
- **Energy Efficiency Research**
  - Online survey of 763 PGE residential customers invited by email to complete the survey during late 2012

# Key Topics & Takeaways

- **Context for Resource Preferences**
  - All customer classes continue to say that environmental issues are a concern
- **Overall Resource Preferences**
  - All customer classes continue to express strong stated preferences for renewables and EE & conservation
- **Preferences for Resource Mix**
  - There is a preference for a resource mix that is NOT highly dependent on one or two sources
  - Stated preferences for greener options continue, even when this means 5% or 10% higher rates for everyone
- **So, What Will <u>Residential</u> Customers Do To Contribute to EE & Conservation?**
  - <u>Residential</u> customers support PGE EE efforts (mostly) and say they are interested in it themselves
    - Though, this is where political differences have a big impact
  - <u>Residential</u> customers also say they have already done a lot, and try pretty hard to manage energy use

DEFINITIVE INSIGHTS

# Concerns with Local Environmental Issues Tend to Be Highest, But Global Warming Is Also Important

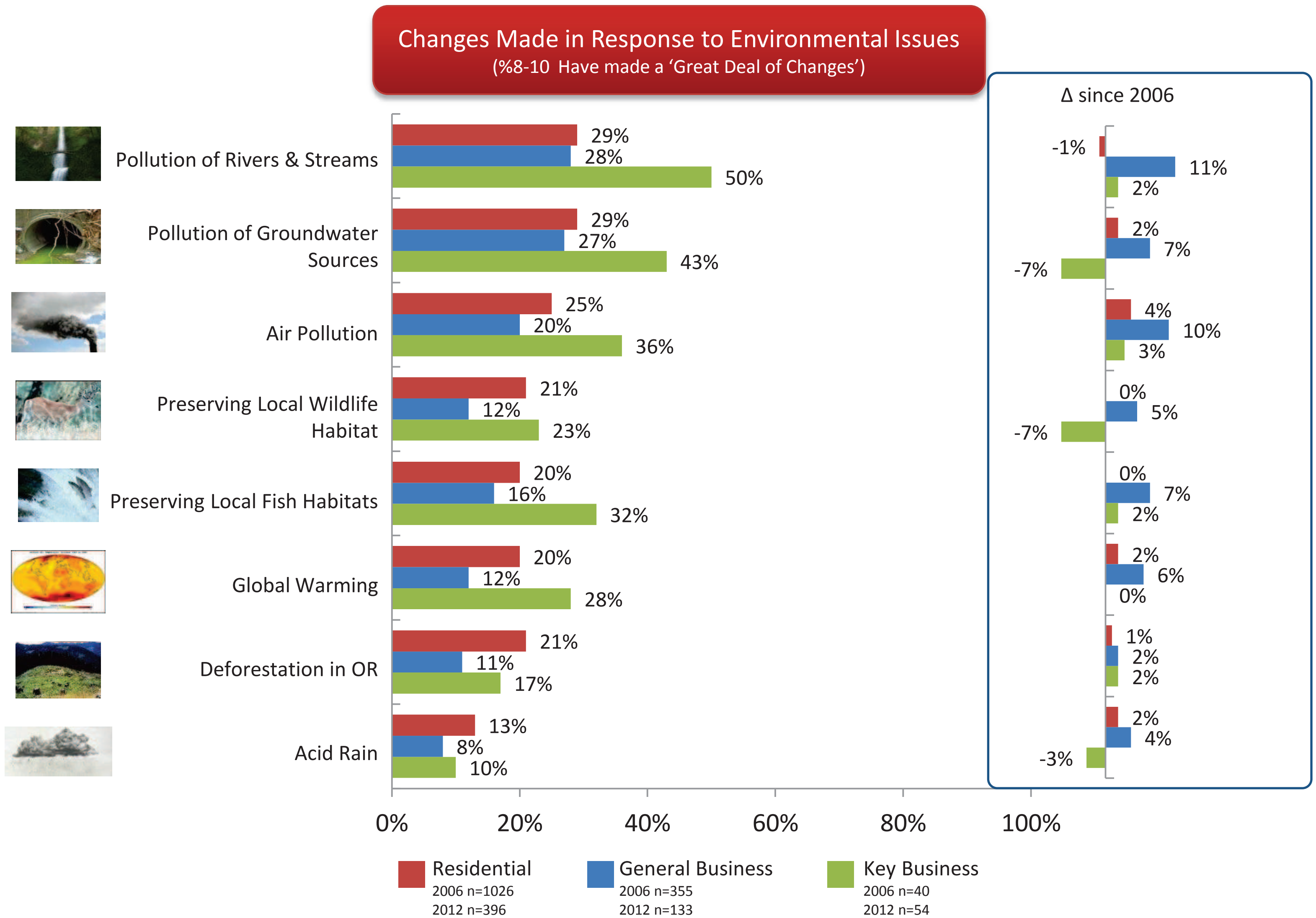



DEFINITIVE INSIGHTS

S15/S29 (2006); S10/S27 (2012): How serious a concern would you say each of the following global environmental issues is for you as a resident of Oregon? 0=Not at all serious concern; 10=Extremely serious concern.

5

# Most Customers (Excepting Some Key Businesses) Have Not Done Much In Response To These Concerns

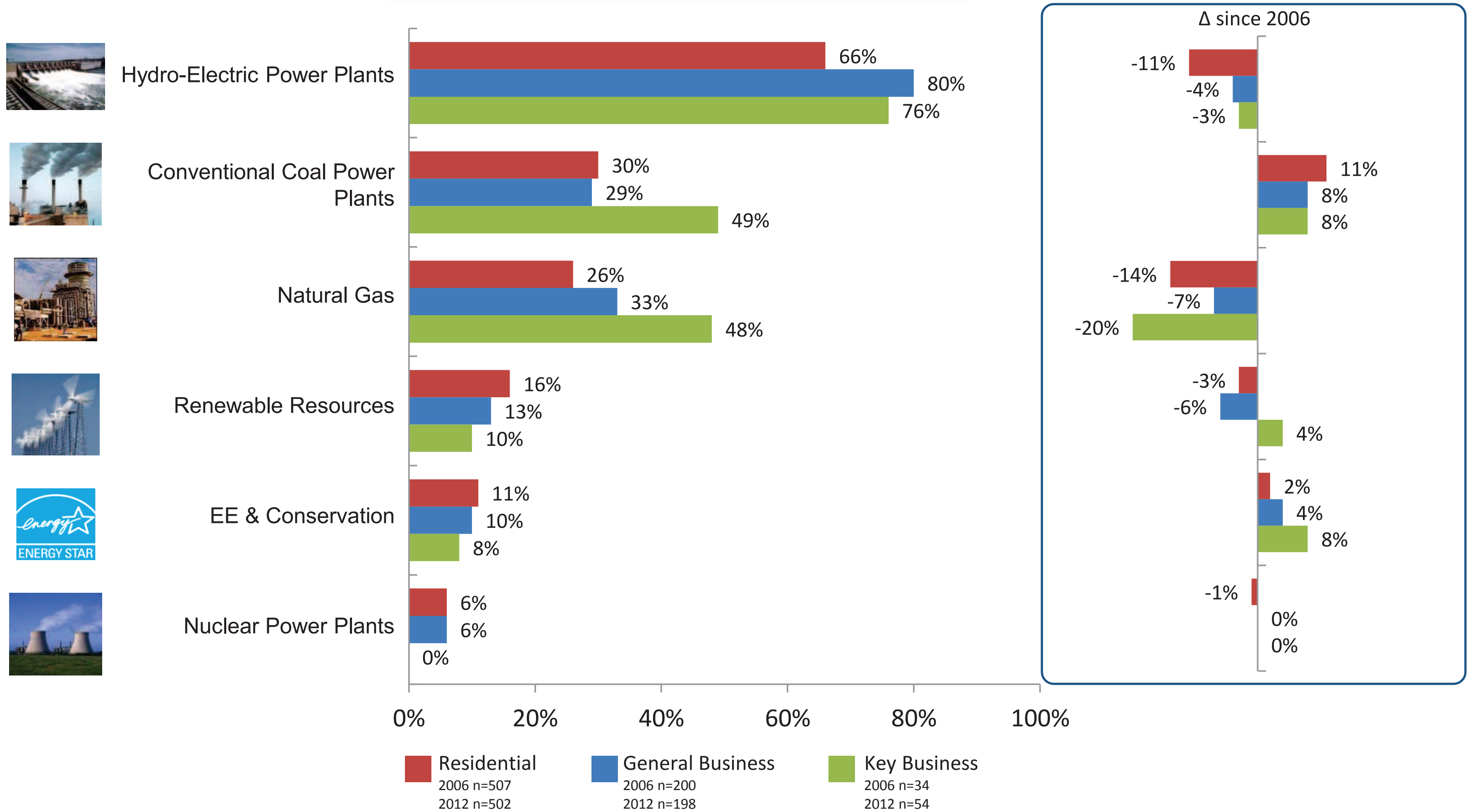



DEFINITIVE INSIGHTS

S16/S30 (2006); S11/S28 (2012): To what degree have you made changes in the way you buy or use products and services in response to each of the environmental issues just discussed? 0=Little or no change; 10=A great deal of change.

# Customers Most Often Assume That Hydro is Central to the PGE Power Supply

Opinions of Resource that Accounts for Greatest/2nd Greatest Proportion of PGE's Power Supply




DEFINITIVE INSIGHTS

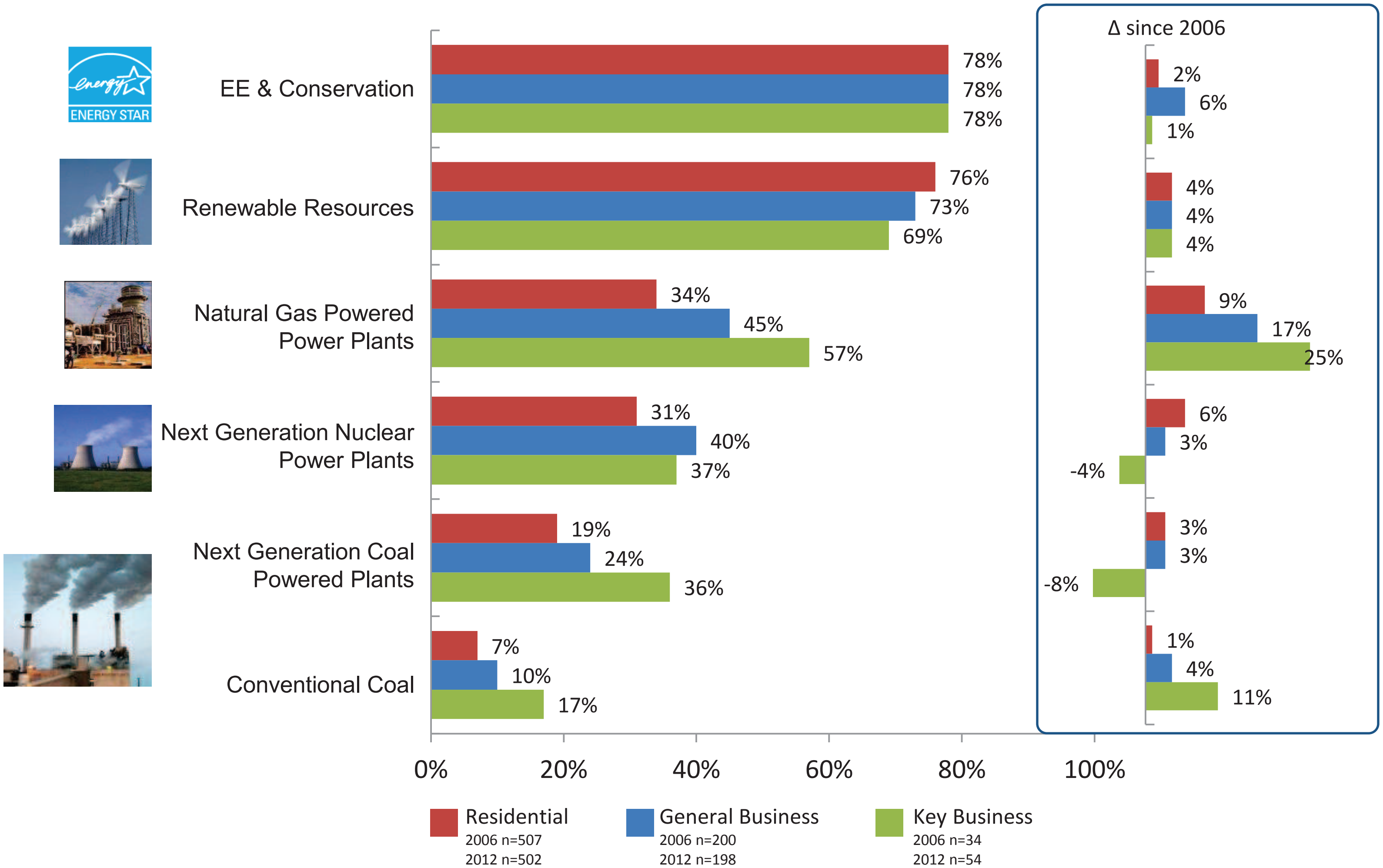
Q5/6: Which one of these resources do you think currently accounts for the greatest/second greatest proportion of PGE's power supply?

# Overall Customer Resource Preferences


8

# Customers Across All Customer Classes Continue to Say That They Prefer EE / Conservation & Renewables

**Preference for Conventional Resources Before Resource Descriptions**
(Preference for Including Conventional Resources in a Long-Term energy supply plan for Oregon (% 8-10) **before** resource description)



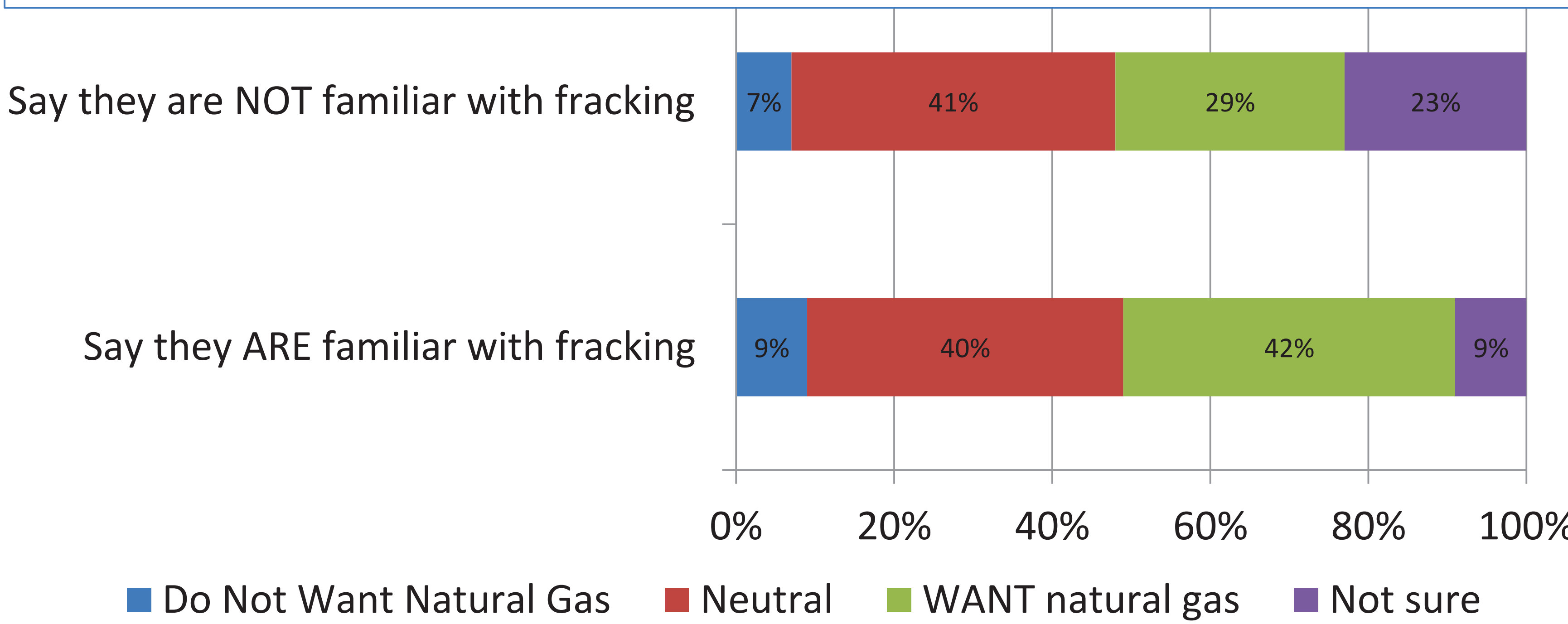

DEFINITIVE INSIGHTS

Q4 (2006 &2012). Please tell us how much you prefer that each type of resource be included in a future energy plan for Oregon. 0=Definitely do not want this resource included in such a plan, 10=Definitely want this resource included in such a plan.

# Natural Gas Preferences & Fracking

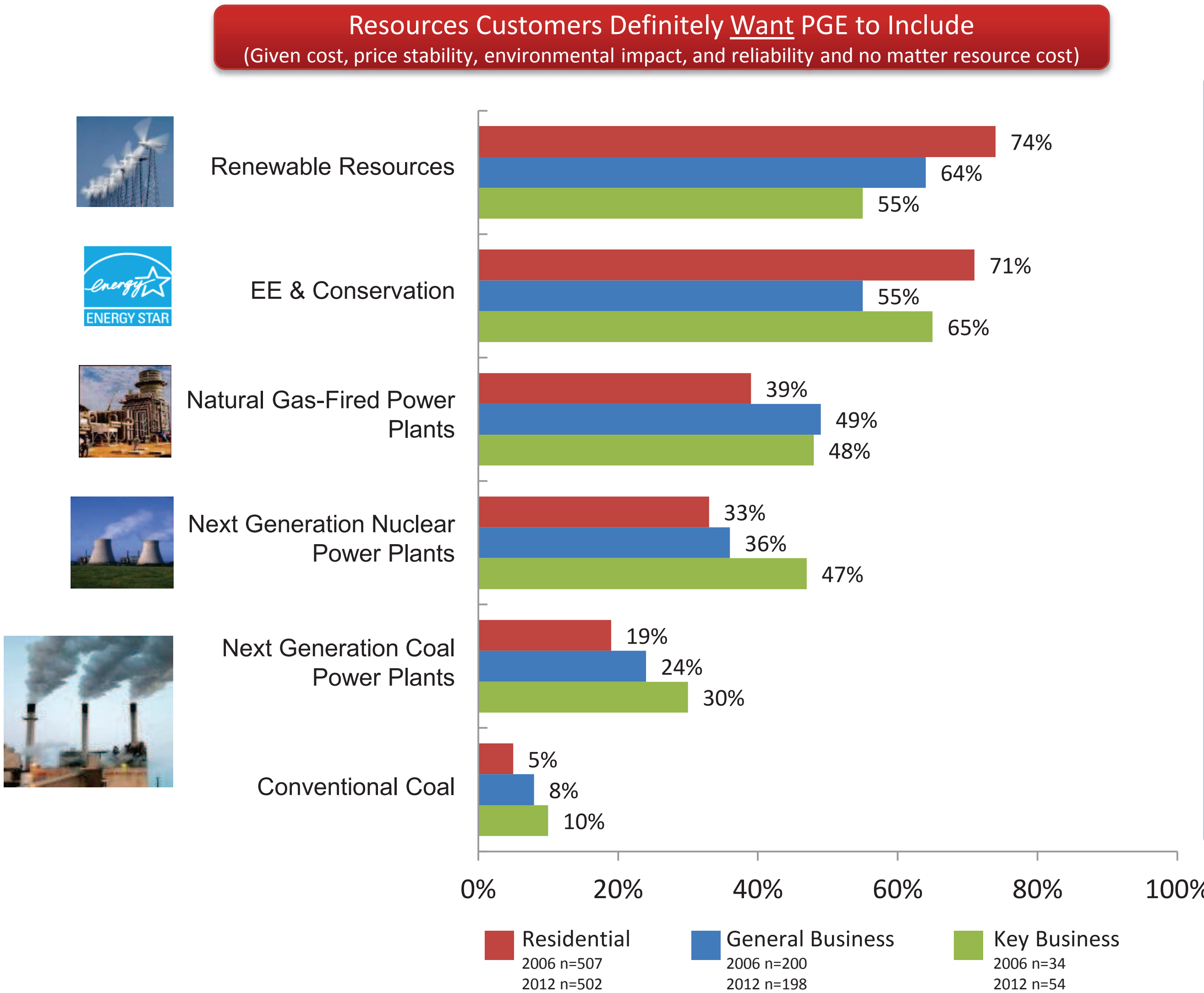
- Customers who say they are familiar with fracking are slightly more positive toward natural gas, though not dramatically so

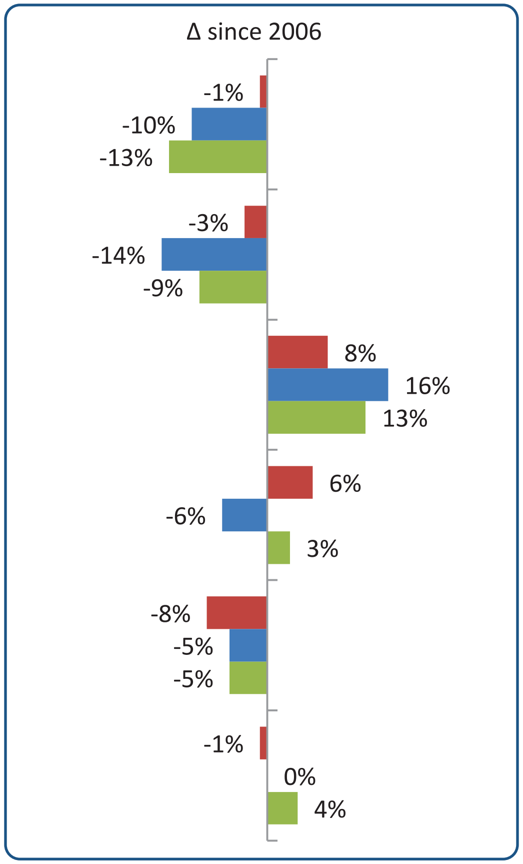
**Preference for Including Natural Gas in Resource Portfolio by Familiarity with Fracking**




DEFINITIVE INSIGHTS

# And Customers Retain the Same Preferences, Regardless of the Cost of Those Resources



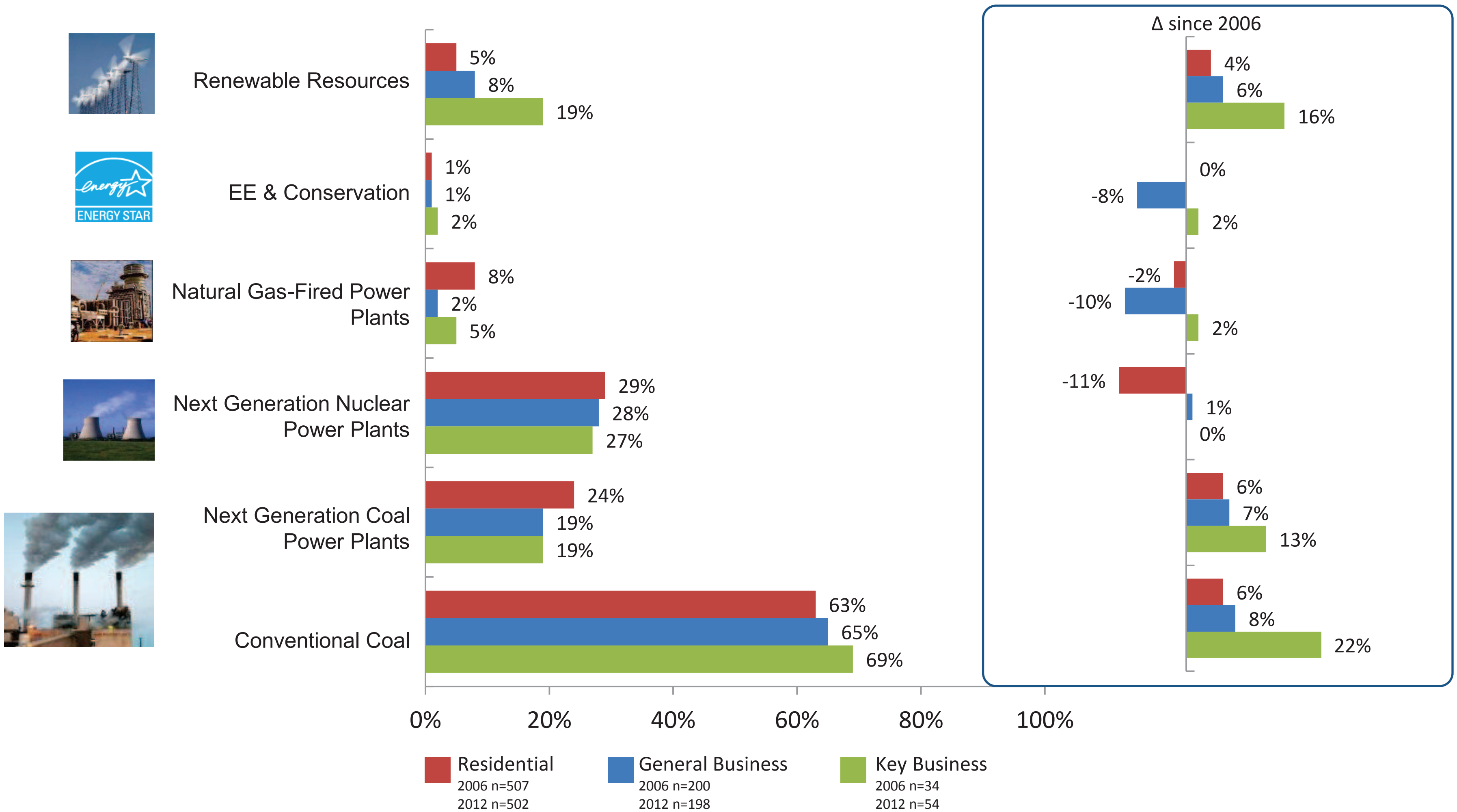




DEFINITIVE INSIGHTS

Q15 (2006) Q19 (2012) Which of these resources would you definitely want PGE to include in a future electricity supply plan regardless of how expensive it was relative to other options?

# When The Question is Flipped (What Do You Not Want Regardless of How Cheap It Is?): Coal is The “Winner”

**Resources Customers do NOT Want PGE to Include**
(Given cost, price stability, environmental impact, and reliability and no matter resource cost)

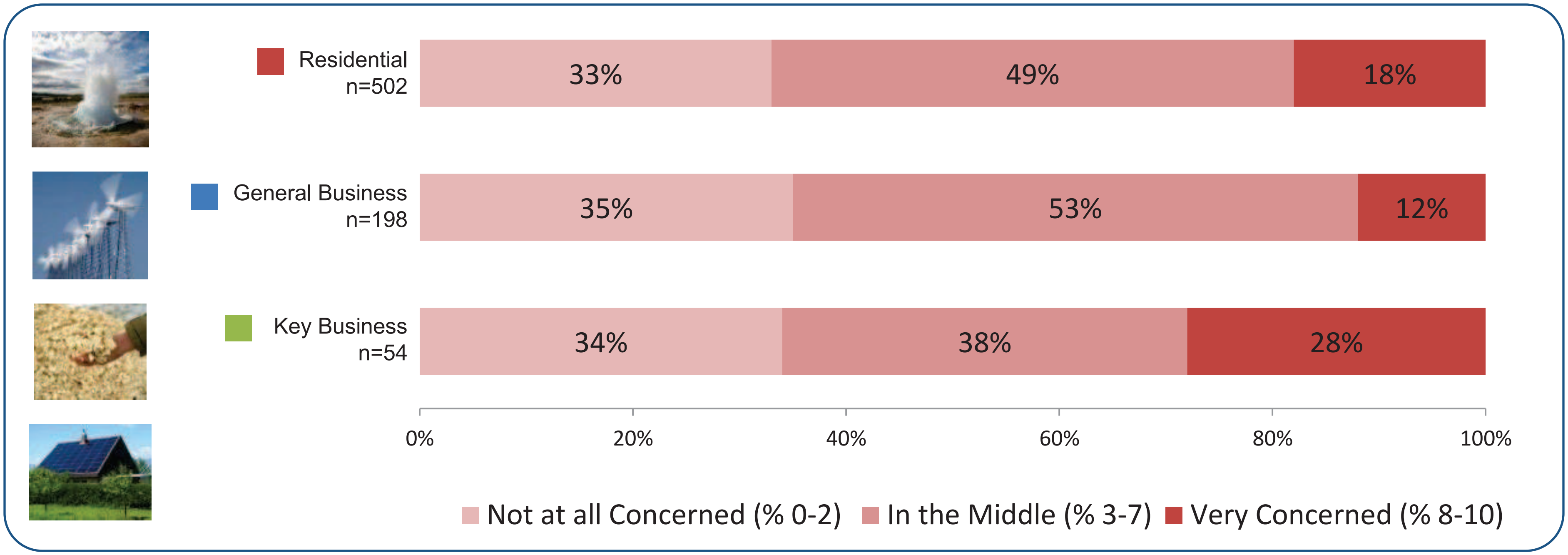



DEFINITIVE INSIGHTS

Q16 (2006) Q20 (2012) Which of these resources would you definitely NOT want PGE to include in a future electricity supply plan regardless of how expensive it was relative to other options?

# Key Business Customers More Often Express Concerns with The Negative Impacts of Renewables

Concern About Potential Negative Impacts of Renewable Resources

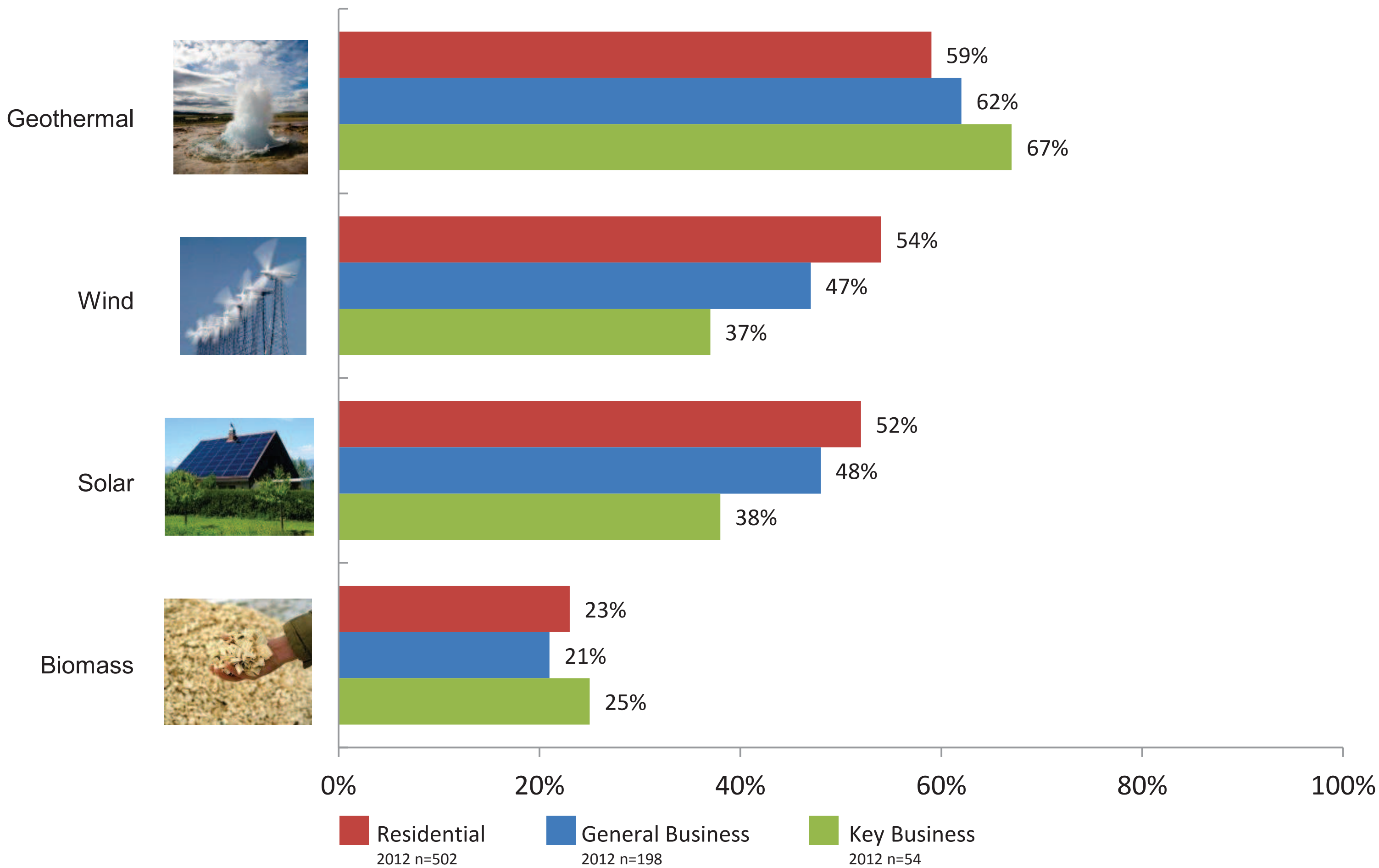



Q64. While many people support the use of renewable resources, other people are concerned that renewable resources do have negative impacts (visual impacts from wind turbines, for example, or the acreage needed for solar farms. How concerned are you about any potential negative impacts from renewable resources?

# Geothermal is the Most Preferred Specific Renewable Resource, While Biomass is Least Preferred

**Preference for Renewable Resources After Resource Descriptions**

(Preference for Including Renewable Resources in a Long-Term energy supply plan for Oregon (% 8-10) **after** resource description)

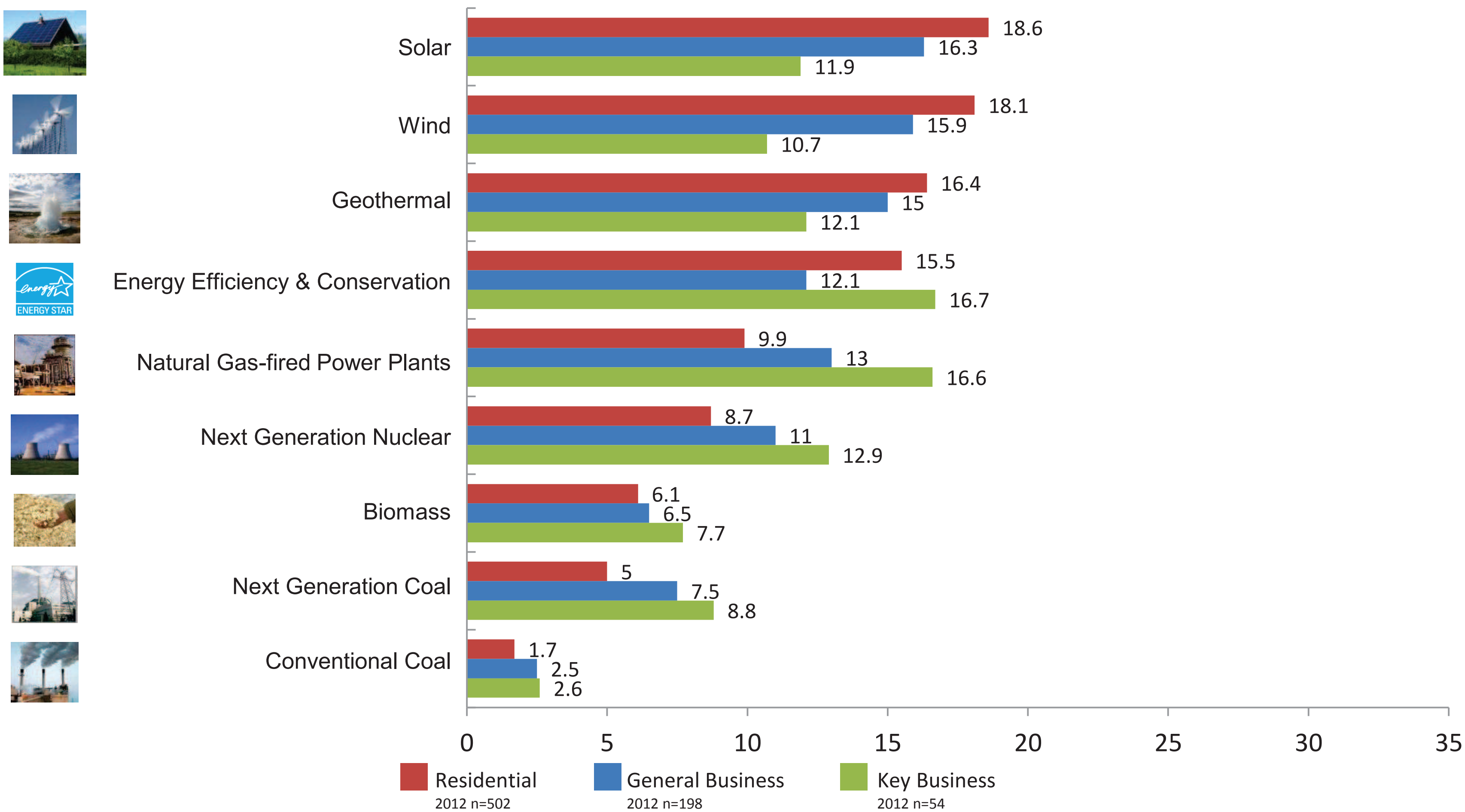



DEFINITIVE INSIGHTS

Q43A-Q43D (2012 Only) Given these factors, please rate (resource) in terms of the extent to which you would prefer that renewables be part of PGE's long-term energy supply plans. 0=Definitely do not want this resource included in such a plan, 10=Definitely want this resource included in such a plan.

# Customers Want A Diverse Energy Supply Portfolio, But Composed Mostly of Renewables And EE & Conservation

**'Perfect' Energy Supply Plan – Including Specific Renewables**
100 Points Allocated Across Nine Resources, Given Equal Prices
(Mean Points Allocated)

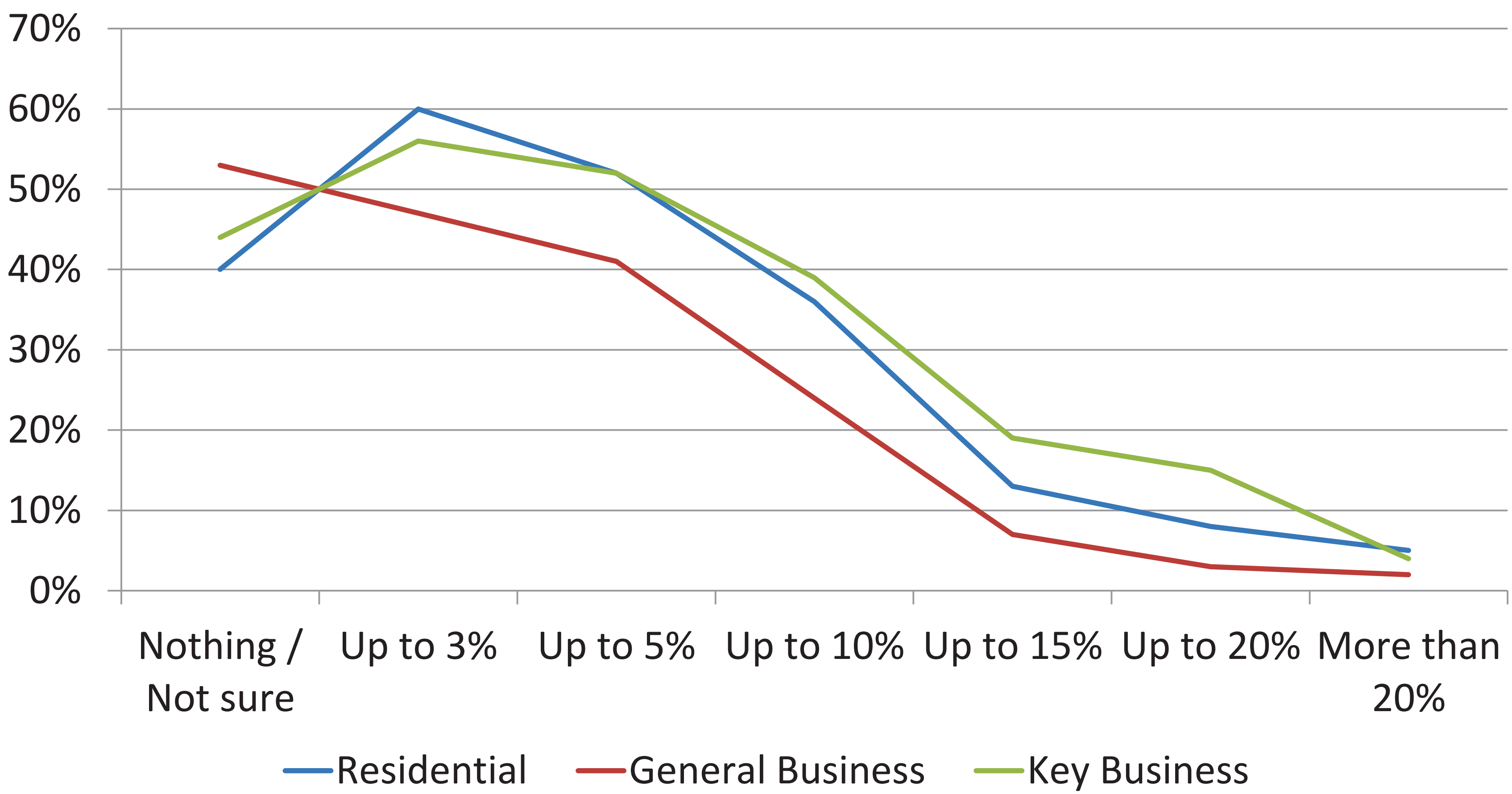



DEFINITIVE INSIGHTS

Q43E (2012 only): Please allocate 100 'points' across the different energy resources below in a way that indicates which resources you would most like to see developed, given what you now know about these resources. (note: max of 40 allotted to any single resource)

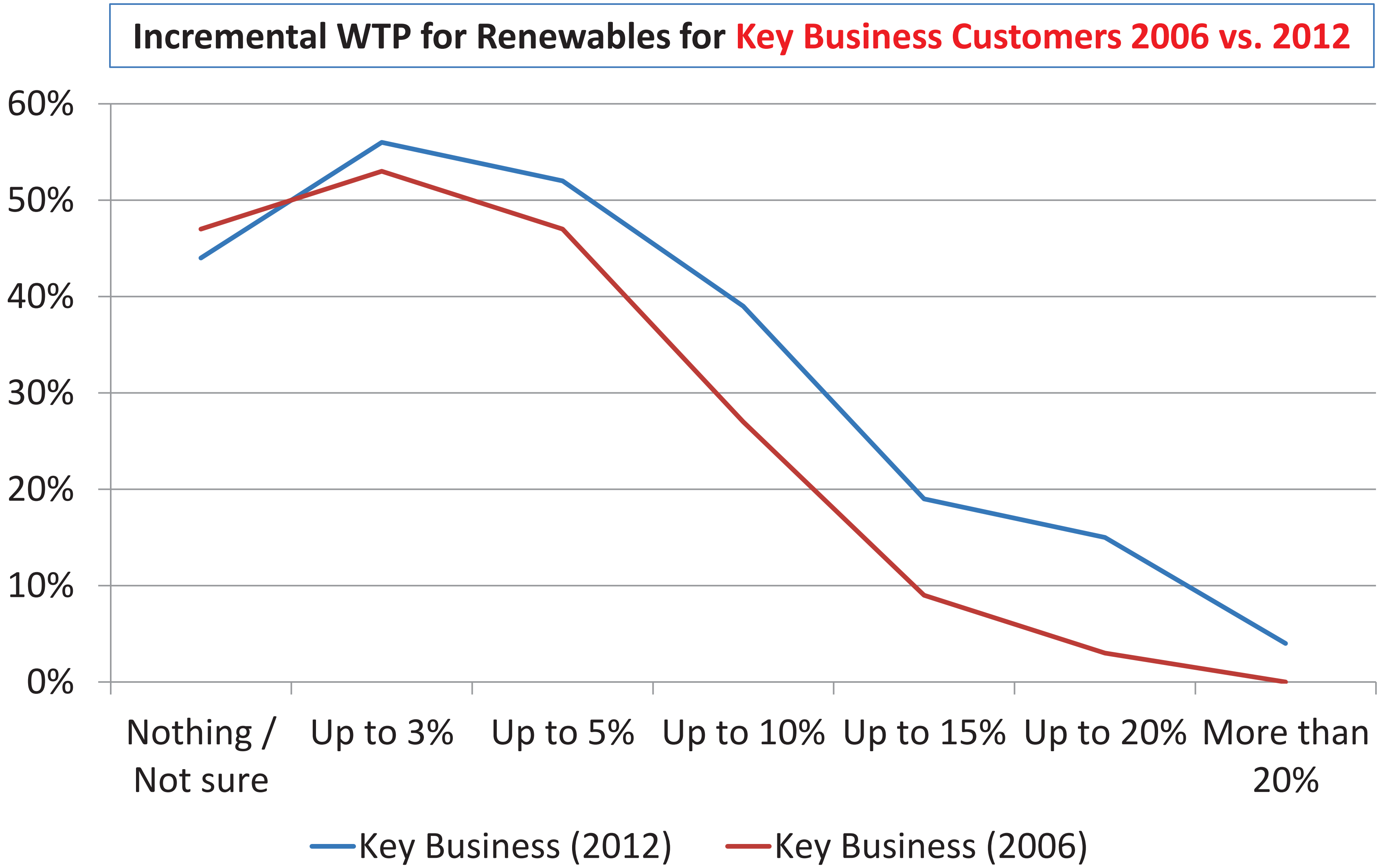
# Customers Continue To Say They Will Pay More for Renewable Resources Themselves

**Incremental WTP for Renewables for All Customer Classes 2012**




DEFINITIVE INSIGHTS

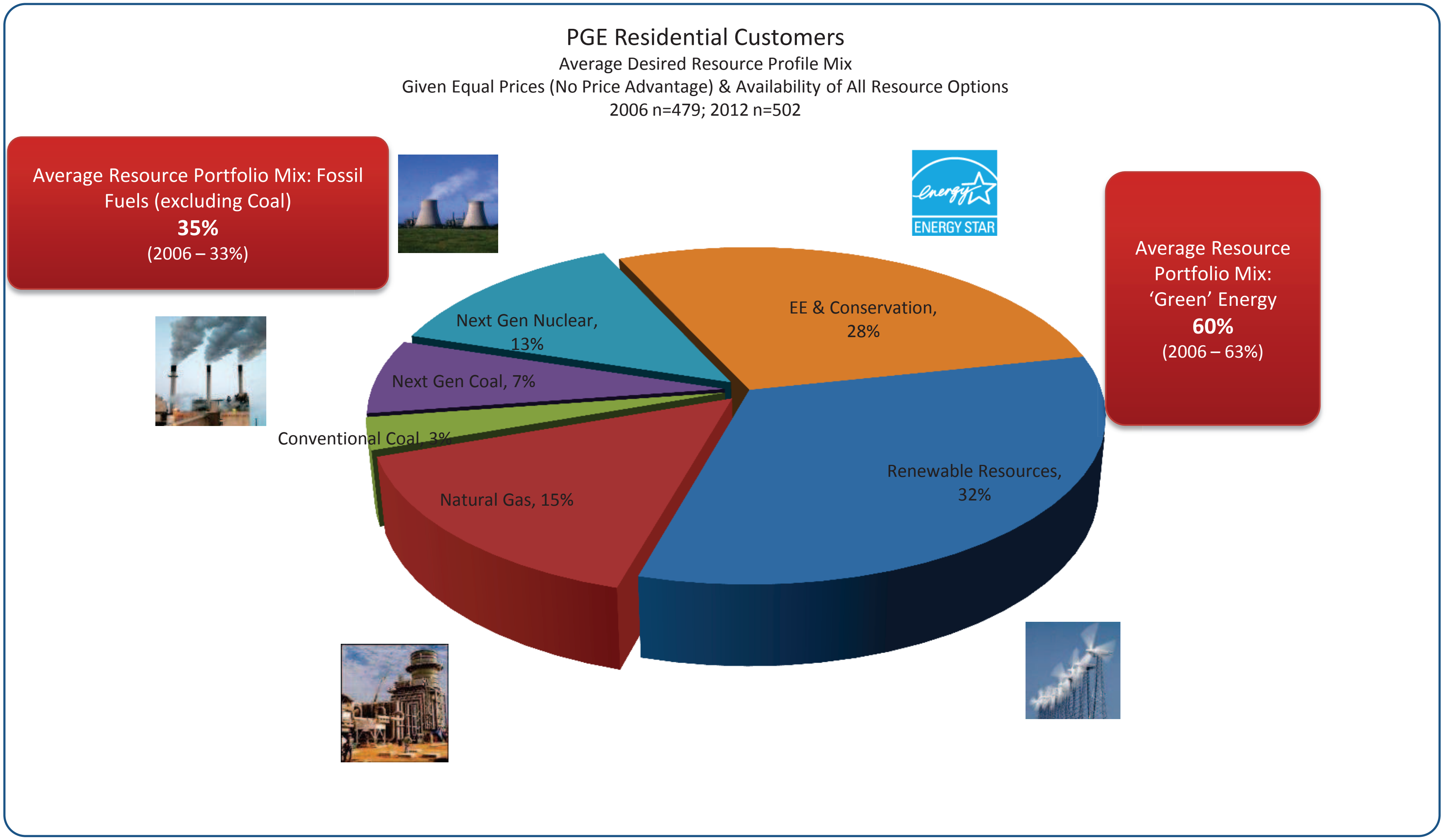
# And Key Business Customers Have Trended To Say They Will Also Pay More Since 2006




DEFINITIVE INSIGHTS

# Understanding Customer Preferences for Resource Mix

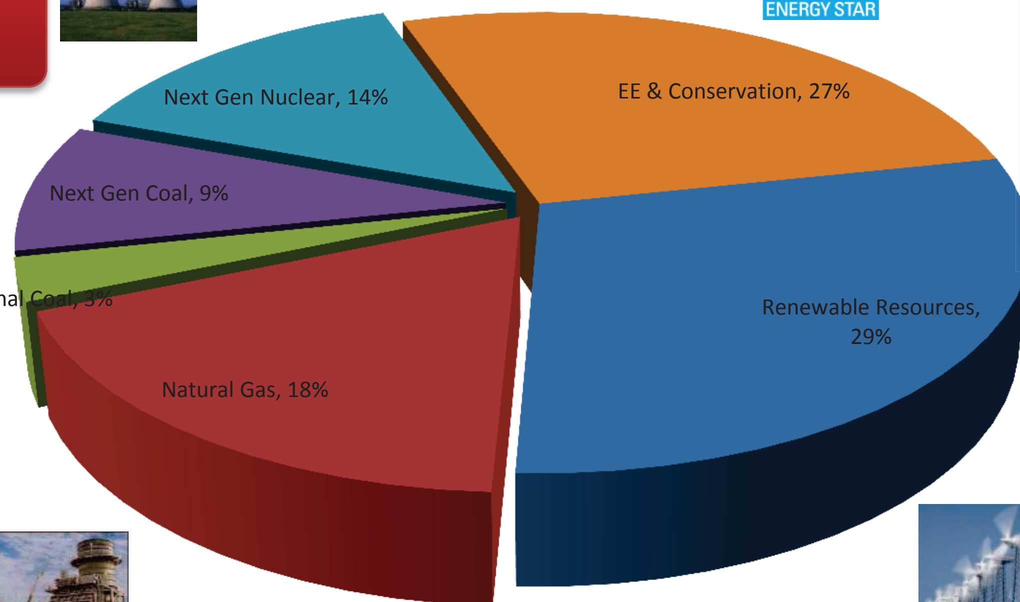
# When Residential Customers Outline Their Preferred Resource Mix , Non-Green Options Make Up 35% of The Supply



# For Business Customers, Non-Green Options Make Up 41% of the Resource Mix

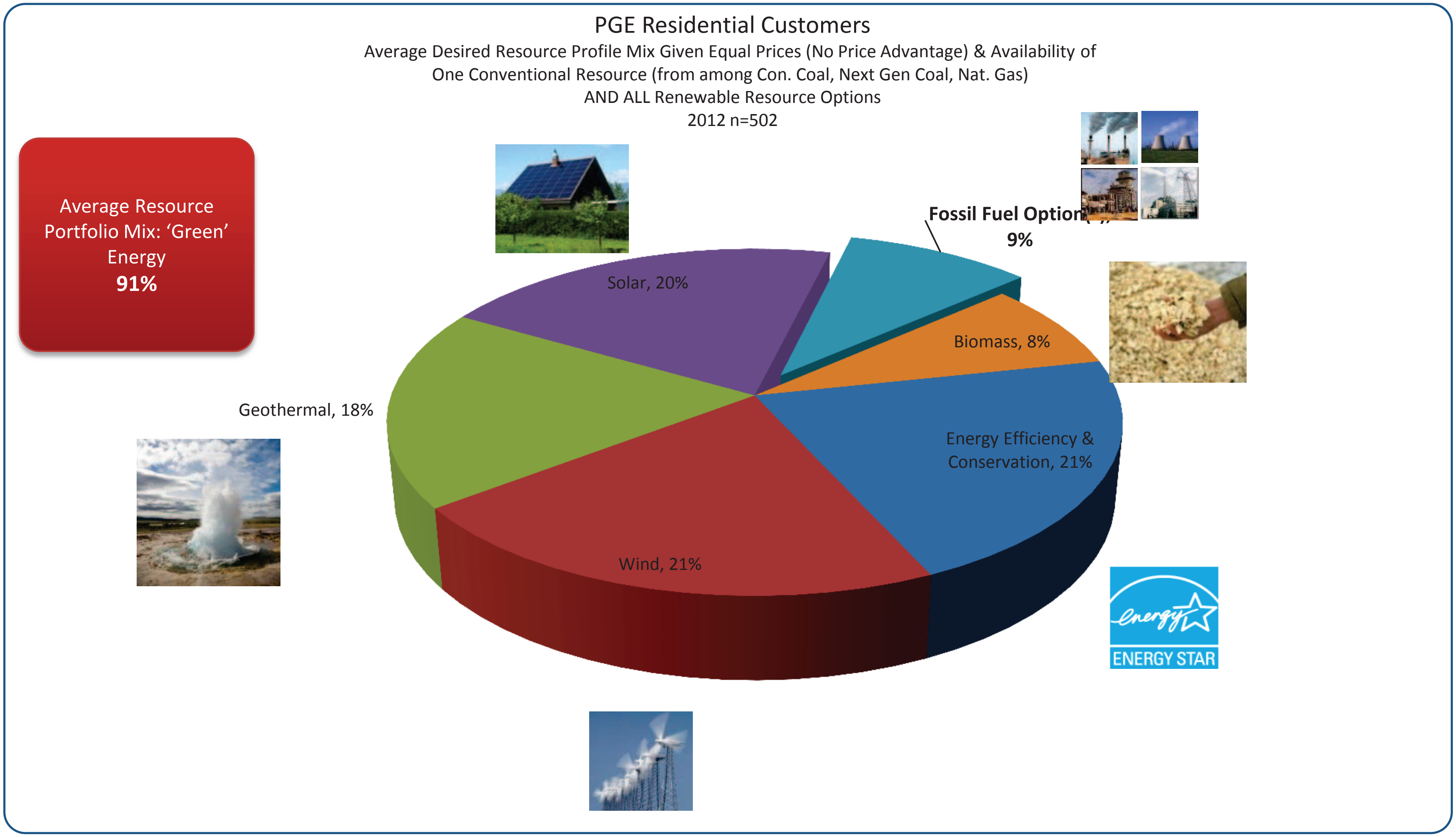
PGE Business Customers
Average Desired Resource Profile Mix
Given Equal Prices (No Price Advantage) & Availability of All Resource Options
2006 n=225; 2012 n=252

Average Resource Portfolio Mix: Fossil Fuels (excluding Coal)
**41%**
(2006 – 44%)




Average Resource Portfolio Mix: 'Green' Energy
**56%**
(2006 – 53%)

# When Residential Customers Can Choose From Among One Fossil Fuel + All Available 'Green' Options, The Fossil Options Gets 9%




Poisson Regression Results – Q44-Q53

DEFINITIVE INSIGHTS

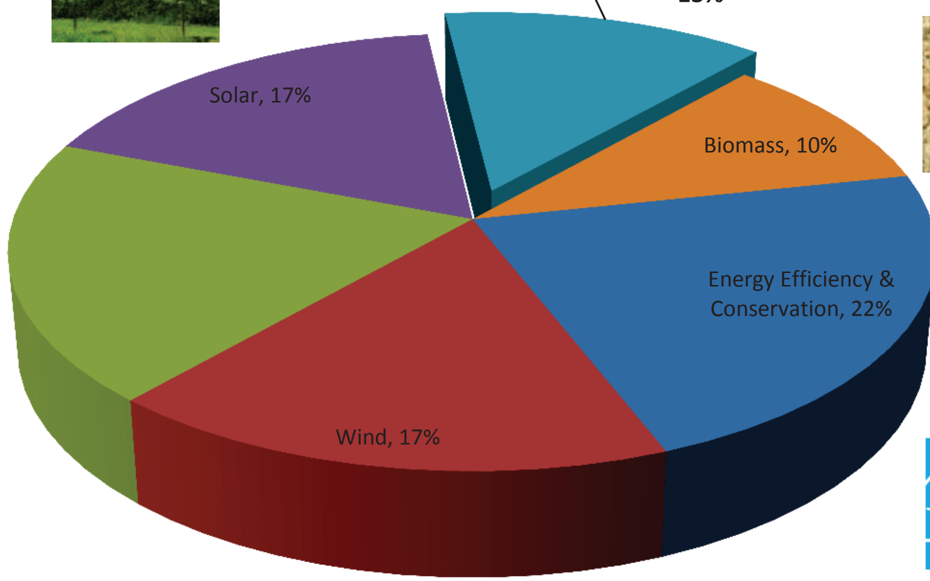
# When Business Customers Have the Same Choices Their Responses Are Very Similar

PGE Business Customers

Average Desired Resource Profile Mix Given Equal Prices (No Price Advantage) & Availability of One Conventional Resource (from among Con. Coal, Next Gen Coal, Nat. Gas) AND ALL Renewable Resource Options

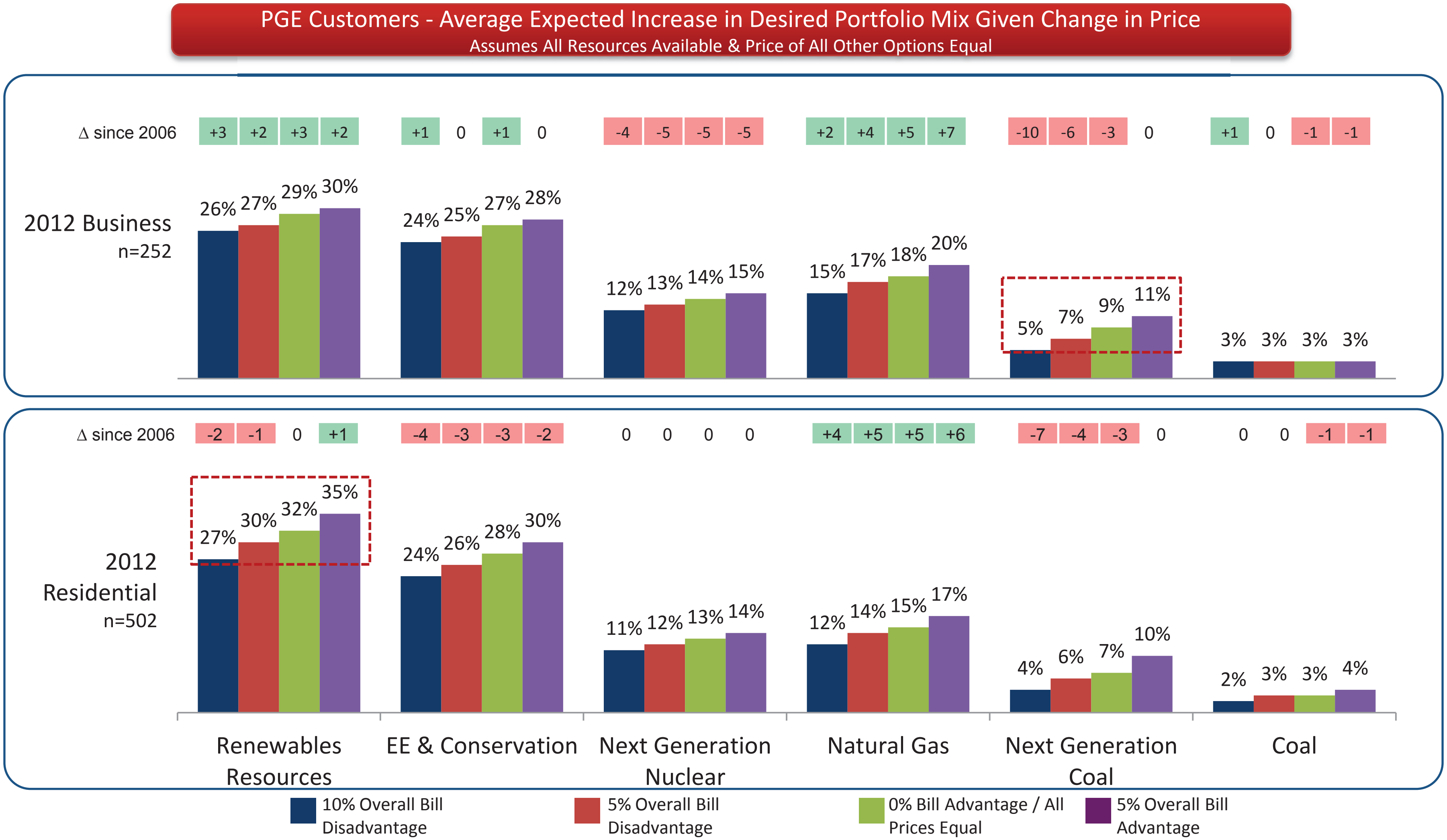
2012 n=252

Average Resource Portfolio Mix: 'Green' Energy
**87%**




Poisson Regression Results – Q44-Q53

# Customers Are Only Slightly Sensitive to Bill Impacts: When A Given Resource Would Increase Bills, Preference Share Goes Down – A Bit



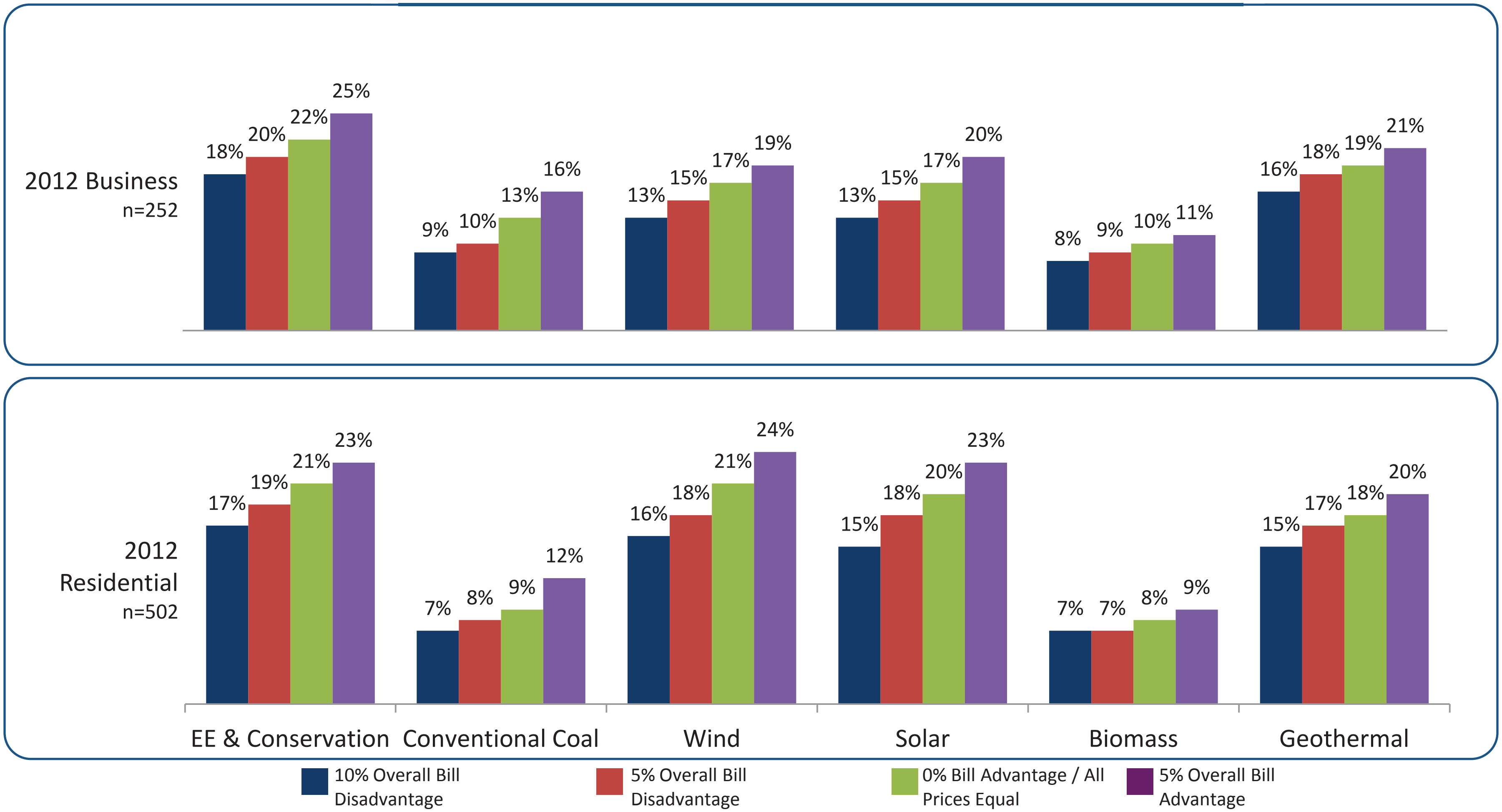

[1] *The summary measure for the relationship between the prices of each resource present in a given scenario is called "price advantage" in this analysis. The price advantage of a given resource option is dependent not on the absolute value of the prices of competing resource options, but rather the differences in these prices. That is, looking at just two energy resources priced at $100 and $150 dollars respectively, we could say that the first resource has a $50 price advantage. Similarly, if the two energy resource options were priced at $50 and $100, the first option still has just a $50 price advantage. Conversely, the second option has a $50 price* disadvantage.

DEFINITIVE INSIGHTS

A19,20,21,22,23,24,25,26,27,28,29,30,31,32,32b, 32d (2006) Q24,26,29,30,32 (2012)

# Similar – Small Levels of Price Sensitivity – Are Seen For Green Resource Options

**Average Expected Increase in Desired Portfolio Mix Given Change in Price**
Assumes All Resources Available & Price of All Other Options Equal




[1] *The summary measure for the relationship between the prices of each resource present in a given scenario is called "price advantage" in this analysis. The price advantage of a given resource option is dependent not on the absolute value of the prices of competing resource options, but rather the differences in these prices. That is, looking at just two energy resources priced at $100 and $150 dollars respectively, we could say that the first resource has a $50 price advantage. Similarly, if the two energy resource options were priced at $50 and $100, the first option still has just a $50 price advantage. Conversely, the second option has a $50 price* disadvantage.

DEFINITIVE INSIGHTS

Q44,46,48,50,52 (2012)

# So, What Will RESIDENTIAL Customers Do To Contribute to Energy Efficiency & Conservation?

DEFINITIVE INSIGHTS

# Summary: What Do RESIDENTIAL Customers Say They Will Do?

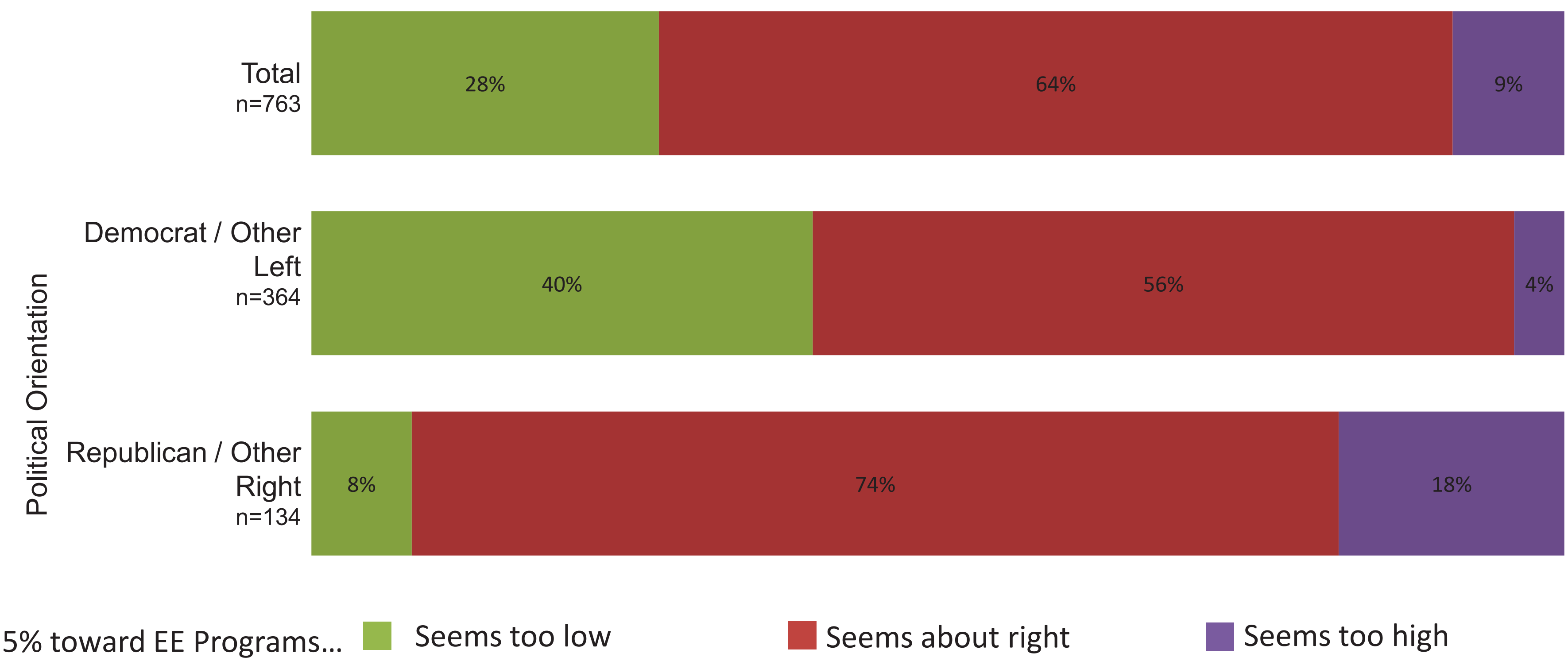
- Residential customers express support for PGE EE actions and charges (mostly) and say they are interested in pursuing EE themselves
  - This is where political differences have a big impact, however

- Residential customers say they have already done a lot, and try pretty hard to manage energy use
  - As a result, they don't think that new programs would make a lot of difference
  - In fact, they don't think that current programs (like rebate programs) make that much of a difference

DEFINITIVE INSIGHTS

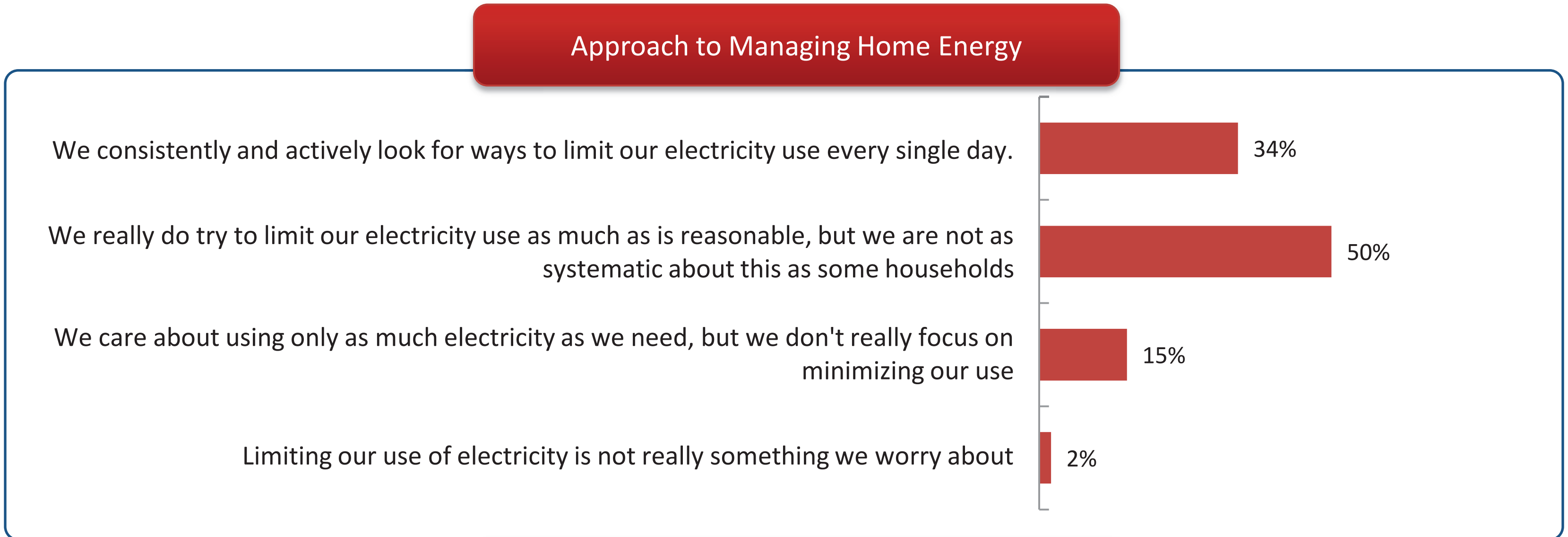
# Most Residential Customers Support EE Bill Charges

About 5% of Residential Bill Goes to EE Programs, this amount…




DEFINITIVE INSIGHTS (Q38) Currently, under Oregon law, about 5% of the average residential customer's bill goes to programs to promote greater energy efficiency. Which of the following statements best describes your thinking about this?

# And Most Say They Actively Try And Limit Their Home Energy Use on A Day-To-Day Basis; Most Say They Already Try to Purchase EE Equipment As Often As Possible





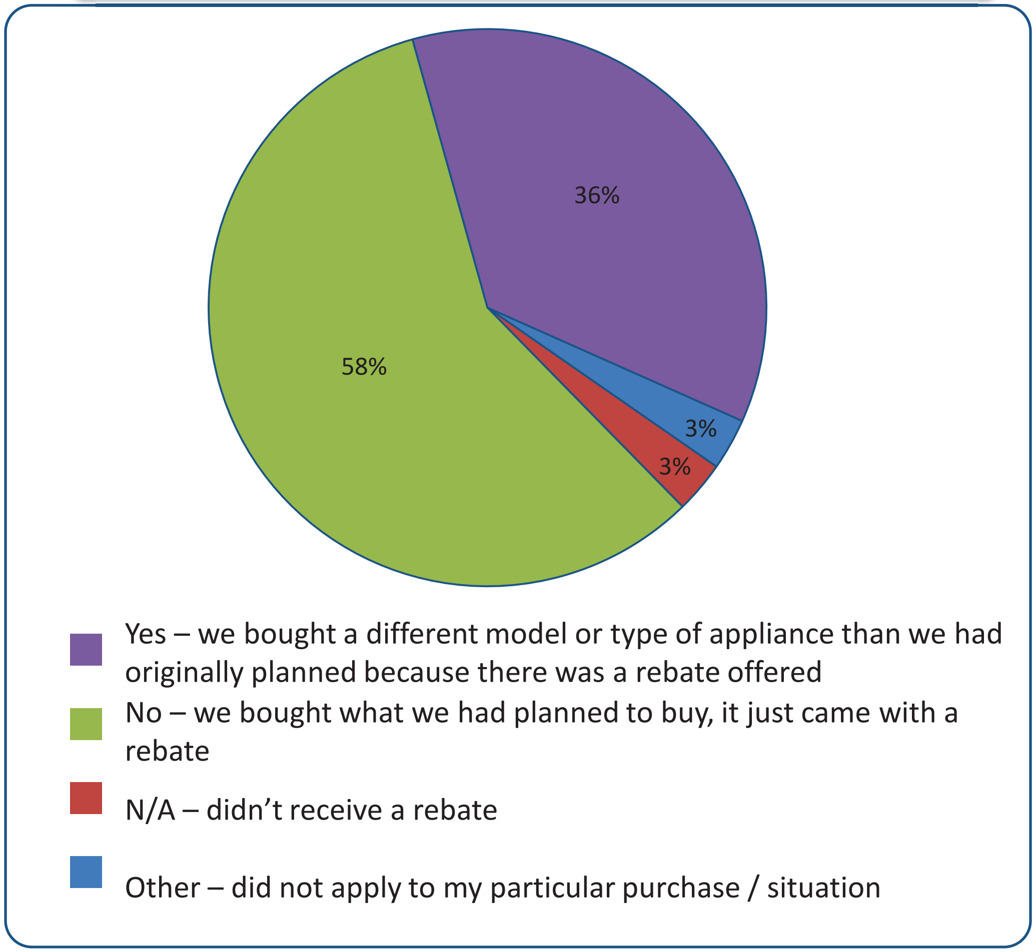
DEFINITIVE INSIGHTS

(Q8) Thinking of your entire household, which of the following best describes your household's overall approach to managing energy use around your home on a day-to-day basis?
(Q10) Which of the following best describes your household's approach to buying new appliances, light bulbs, or other electricity using devices?


28

# As A Result, Many Say That Current Programs Do Not Much Affect Their Behavior

Impact of Rebate on Purchase
(Base: those who received a rebate, or some other type of financial incentive; n=307)




DEFINITIVE INSIGHTS

(Q23) Thinking about the last rebate you received, did you purchase a different appliance or other energy-related measure than you had planned to buy specifically in order to receive the rebate?

# Summary Takeaways

- **Context for Resource Preferences**
  - All customer classes continue to say that environmental issues are a concern
- **Overall Resource Preferences**
  - All customer classes continue to express strong stated preferences for renewables and EE & conservation
- **Preferences for Resource Mix**
  - There is a preference for a resource mix that is NOT highly dependent on one or two sources
  - Stated preferences for greener options continue, even when this means 5% or 10% higher rates for everyone
- **So, What Will Residential Customers Do To Contribute to EE & Conservation?**
  - Residential customers support PGE EE efforts (mostly) and say they are interested in it themselves
  - Residential customers say they have already done a lot, and try pretty hard to manage energy use – and they think this limits how much you can incent them to do more

DEFINITIVE INSIGHTS

# *Appendix I*

## *PNUCC Memo Regarding Proposed EPA $CO_2$ Standards*

Attachment C

Bringing the *Power* of good ideas *Together.*

# Memorandum

**To:** **The Power and Natural Gas Planning Taskforce**

**From:** **Tomás Morrissey**

**Date:** **October 10, 2013**

**Subject:** **Proposed September 2013 EPA Standards for CO2 Emissions from New Power Plants**

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Background and Proposed Rule

In 2009 EPA Administrator Jackson signed a rule deeming greenhouse gases a threat to public health under section 202(a) of the Clean Air Act.[1] On September 20, 2013, the EPA proposed standards to limit CO2 emissions from new power plants.[2] Please keep in mind that the standards are proposed and may change before they are finalized.

The proposed standards are:

- New coal plants must meet one of two standards. In a one year period they must emit less than 1,100 lbs CO2/MWh on average *or* over a seven year period they must emit less than 1,050 lbs CO2/MWh on average.
    - This effectively prohibits the construction of new coal plants that do not feature carbon capture and sequestration technology.
- Larger new natural gas plants must emit less than 1,000 lbs CO2/MWh on average over a one year period. Smaller new natural gas plants must emit less than 1,100 lbs CO2/MWh over a one year period.[3]

[1] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule." Federal Register, Vol. 74, No. 239, Page 66496. December 2009.
[2] The rule can be found at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf
[3] The EPA defines a the size limit for a small plant as having "a heat input rating that is less than or equal to 850 MMBtu/h" which roughly translates to a 100 MW unit. See page 88 of the rule for more details.

101 S.W. Main Street, Suite 1605 Portland, OR 97204-3224

Attachment C

One key exemption to the proposed standards:

- The standards only "apply to a facility if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year" on a three year rolling average basis.[4]
    - This provision effectively excludes new peaking units from the proposed rules.

<u>Impact on the Northwest Power Industry</u>

These proposed rules will likely have no immediate impact on the Northwest power industry. Although the rules make it very difficult to construct new coal fired generation the Northwest is not planning any new coal builds at this time. New baseload gas units should be able to meet the 1,000 lbs CO2/MWh restriction without extra costs and new peaking units will likely be exempt from the rule. The rule will set a precedent of EPA CO2 regulation in the electric power sector. The EPA is expected to issue CO2 regulations that apply to existing power plants in upcoming years.

# *Appendix J*

## *PGE WECC Resource Expansion Details*

# *Appendix J: PGE WECC Resource Expansion Details*

Table J-1 details the long-term resource additions by area in the Western Electricity Coordinating Council (WECC). The period of the analysis is 2014-2033. All areas with an RPS standard contain a significant percentage of renewable resources in their incremental resource mix.

Table J-2 shows resources added in the WECC by technology.

**Table J-1: Resource Added by Area (Nameplate MW, 2014-2033)**

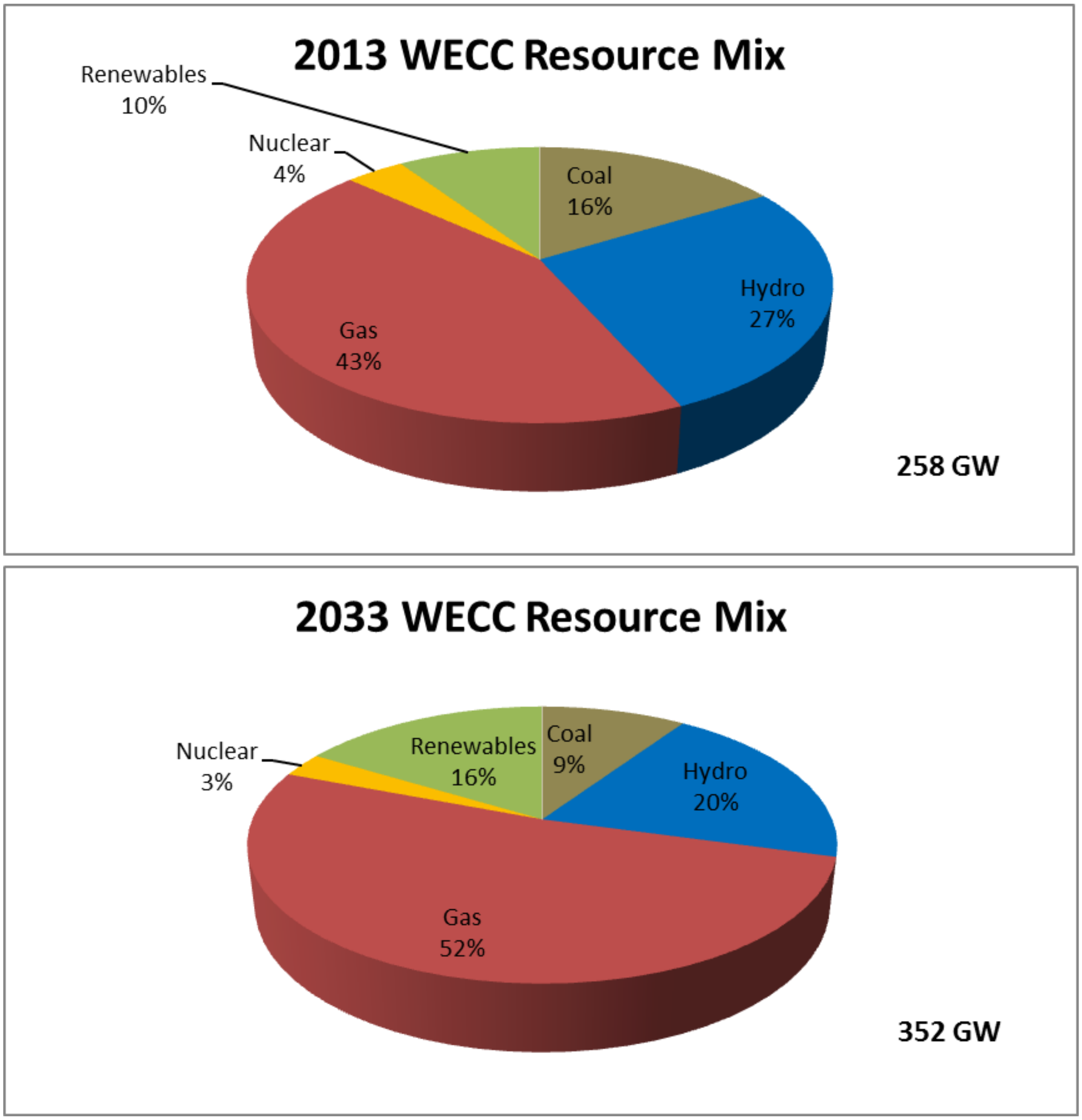
| | Aurora Selections | RPS Resources | Total | RPS Percentage |
|---|---|---|---|---|
| Arizona | (8,670) | 2,472 | (6,199) | NA |
| Canada-Alberta | 18,024 | | 18,024 | 0% |
| Canada-British Columbia | 6,920 | | 6,920 | 0% |
| California | 16,690 | 14,209 | 30,899 | 46% |
| Colorado | 3,273 | 3,342 | 6,615 | 51% |
| Idaho South | 4,550 | - | 4,550 | 0% |
| Montana | 10,074 | 421 | 10,495 | 4% |
| Nevada | 6,493 | 2,465 | 8,958 | 28% |
| New Mexico | 5,210 | 957 | 6,167 | 16% |
| Pacific Northwest | 789 | 4,215 | 5,003 | 84% |
| Utah | 695 | | 695 | 0% |
| Wyoming | (351) | 1,969 | 1,618 | NA |
| **Total** | | | **93,744** | |

**Table J-2: Cumulative Resource Additions by Technology, Nameplate (MW)**

| | MW |
|---|---|
| RPS Renewables | 30,049 |
| Other Renewables | 3,040 |
| CCCT - Gas | 74,260 |
| SCCCT/Peakers - Gas | (4,923) |
| Coal | (8,682) |
| **Total (2014-2033)** | **93,744** |

Figure J-1 shows the WECC resources by technology in 2013 and then by 2033, after the AURORAxmp resource expansion. Capacity by 2033 increased by almost 40% compared to the current levels.

**Figure J-1: WECC Resource Mix by Technology, 2013 and 2033**



Tables J-1 and J-2 and Figure J-1 summarize net resource changes. They include both additions and retirements. The summary figure of approximately 94 GW over the 20-year period ending in 2033 is the net of 110 GW of additions and 16 GW of retirements. Figure 9-2 in the IRP provides detail for both additions and retirements. Retirements are comprised of coal plants, which become subject to carbon taxes in 2023, and older, less efficient, simple cycle combustion turbines. These retirements occur primarily in the Southwest. For example, Table J-1 shows that retirements are greater than additions in Arizona over the analysis period.

Table J-3 shows the long-term annual average electricity prices resulting from our WECC expansion in AURORAxmp.

**Table J-3: WECC–Long-Term Annual Average Electricity Prices (Nominal $ per MWh)**

| | Alberta | Arizona | British Columbia | CA-NP15+ | CA-PG&E-ZP26+ | CA-SP15+ | Colorado | IdahoSouth | Mexico-BajaCANorth | Montana | Nevada North | Nevada South | NewMexico | PNW | Utah | Wyoming |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 56.95 | 34.76 | 47.11 | 40.9 | 39.24 | 40.72 | 34.91 | 34.38 | 39.05 | 31.4 | 37.56 | 37.23 | 32.88 | 33.45 | 34.66 | 30.23 |
| 2015 | 49.13 | 35.3 | 41.7 | 41.51 | 39.79 | 41.3 | 34.94 | 33.83 | 39.88 | 31.65 | 37.89 | 37.55 | 33.56 | 33.76 | 35.09 | 30.1 |
| 2016 | 46.54 | 36.5 | 42.79 | 42.67 | 40.92 | 42.48 | 36.38 | 35.19 | 40.71 | 32.73 | 39.12 | 38.79 | 34.98 | 34.89 | 36.27 | 31.35 |
| 2017 | 49.31 | 39.87 | 47.09 | 46.63 | 44.81 | 46.35 | 39.55 | 37.92 | 44.47 | 35.7 | 42.69 | 42.48 | 37.93 | 37.95 | 39.68 | 34.06 |
| 2018 | 54.1 | 43.8 | 52.83 | 50.84 | 48.99 | 50.61 | 43.29 | 41.21 | 49.27 | 39.18 | 46.93 | 46.81 | 41.43 | 41.54 | 43.61 | 37.29 |
| 2019 | 56.64 | 47.04 | 55.58 | 54.4 | 52.6 | 54.29 | 46.68 | 44.42 | 53.74 | 41.89 | 50.57 | 50.43 | 44.54 | 44.3 | 47.05 | 40.25 |
| 2020 | 58.05 | 48.54 | 57.91 | 55.34 | 53.55 | 55.37 | 47.97 | 45.3 | 55.8 | 42.3 | 50.71 | 51.35 | 46.01 | 44.8 | 48.07 | 41.15 |
| 2021 | 56.36 | 48.17 | 58.57 | 54.96 | 53.09 | 54.76 | 47.86 | 45.17 | 56.47 | 39.87 | 50.24 | 50.55 | 46.25 | 45.13 | 47.7 | 40.87 |
| 2022 | 58.29 | 51.27 | 60.87 | 58.31 | 56.36 | 57.89 | 51.13 | 47.99 | 60.89 | 41.53 | 52.25 | 53.45 | 49.28 | 47.75 | 50.49 | 43.48 |
| 2023 | 64.87 | 65.56 | 69.81 | 73.41 | 71.23 | 72.73 | 66.68 | 61.9 | 61.2 | 49.96 | 66.83 | 67.82 | 65.01 | 60.57 | 64.91 | 57 |
| 2024 | 64.16 | 67.11 | 70.79 | 75.2 | 72.95 | 74.19 | 68.81 | 64.01 | 62.78 | 50.16 | 68.33 | 69.03 | 67.08 | 63.52 | 66.37 | 58.89 |
| 2025 | 63.58 | 68.53 | 71.17 | 76.91 | 74.73 | 75.38 | 70.15 | 64.89 | 65.83 | 50.59 | 69.48 | 69.04 | 69.04 | 64.72 | 67.68 | 60.13 |
| 2026 | 63.11 | 70.17 | 71.85 | 77.55 | 75.73 | 76.42 | 72.83 | 67.07 | 64.88 | 52.16 | 70.63 | 69.58 | 73.34 | 66.28 | 69.49 | 62.63 |
| 2027 | 62.68 | 71.59 | 71.94 | 78.02 | 76.3 | 77.28 | 73.89 | 67.67 | 70.17 | 52.48 | 71.91 | 70.63 | 75.63 | 66.93 | 70.74 | 63.93 |
| 2028 | 61.73 | 73.26 | 71.97 | 78.41 | 76.66 | 77.75 | 74.74 | 68.06 | 65.79 | 52.82 | 72.35 | 70.78 | 77.92 | 67.51 | 72.26 | 65.07 |
| 2029 | 63.27 | 75.79 | 74.5 | 81.37 | 79.54 | 80.52 | 76.61 | 71.42 | 71.96 | 54.9 | 75.35 | 73.4 | 78.2 | 70.63 | 75.9 | 68.11 |
| 2030 | 64.66 | 79.04 | 75.53 | 83.26 | 81.54 | 82.76 | 79.2 | 73.43 | 82.15 | 56.58 | 77.67 | 75.45 | 79.59 | 72.77 | 78.87 | 70.81 |
| 2031 | 66.37 | 82.14 | 78.45 | 86.25 | 84.48 | 85.52 | 82.47 | 76.33 | 73.59 | 60.87 | 80.67 | 77.84 | 80.97 | 76.1 | 82.73 | 74.28 |
| 2032 | 66.96 | 84.09 | 80.48 | 88.63 | 86.84 | 87.81 | 85.1 | 78.9 | 79.54 | 60.58 | 83.29 | 80.03 | 81.24 | 78.69 | 85.4 | 77.33 |
| 2033 | 67.44 | 86.12 | 82.32 | 90.28 | 88.61 | 89.7 | 87.75 | 80.81 | 85.91 | 63.71 | 85.69 | 81.85 | 83.01 | 80.66 | 88.74 | 80.15 |

# *Appendix K*

## *PGE Load-Resource Balance Details*

# Appendix K: PGE Load-Resource Balance Details

| Figure 3-4 | Annual energy LRB | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| (MWa) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
| Coal | 639 | 639 | 639 | 639 | 639 | 639 | 639 | 256 | 256 | 256 |
| Gas | 581 | 581 | 793 | 944 | 944 | 944 | 944 | 944 | 944 | 944 |
| Hydro | 488 | 487 | 456 | 452 | 418 | 349 | 349 | 349 | 321 | 321 |
| Renewables | 179 | 237 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 |
| EE | 34 | 69 | 99 | 124 | 147 | 166 | 184 | 200 | 216 | 230 |
| Non-Hydro Contracts | 113 | 109 | 86 | 19 | 19 | 67 | 67 | 19 | 19 | 19 |
| **Total Resources** | **2,034** | **2,121** | **2,350** | **2,456** | **2,444** | **2,443** | **2,461** | **2,046** | **2,034** | **2,049** |
| **Load and Reserves** | **2,224** | **2,254** | **2,308** | **2,364** | **2,422** | **2,469** | **2,522** | **2,573** | **2,625** | **2,676** |
| **Surplus or (Deficit)** | **(190)** | **(133)** | **43** | **93** | **23** | **(26)** | **(61)** | **(527)** | **(591)** | **(627)** |

| Figure 3-5 | Winter capacity LRB | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| (MW) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
| Coal | 756 | 756 | 756 | 756 | 756 | 756 | 756 | 296 | 296 | 296 |
| Gas | 1,184 | 1,184 | 1,414 | 1,855 | 1,855 | 1,855 | 1,855 | 1,855 | 1,855 | 1,855 |
| Hydro | 1,140 | 1,130 | 1,072 | 922 | 886 | 739 | 739 | 739 | 664 | 664 |
| Renewables | 43 | 43 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| EE | 47 | 93 | 128 | 158 | 183 | 205 | 223 | 240 | 256 | 272 |
| Non-Hydro Contracts | 229 | 213 | 209 | 109 | 109 | 67 | 67 | 9 | 9 | 9 |
| Demand Response | 28 | 35 | 45 | 45 | 45 | 45 | 46 | 49 | 53 | 58 |
| DSG | 97 | 104 | 110 | 116 | 122 | 122 | 122 | 122 | 122 | 122 |
| **Total Resources** | **3,524** | **3,557** | **3,790** | **4,018** | **4,013** | **3,846** | **3,866** | **3,368** | **3,313** | **3,334** |
| **Load and Reserves** | **3,753** | **3,793** | **3,823** | **3,935** | **4,010** | **4,063** | **4,126** | **4,156** | **4,215** | **4,277** |
| **Surplus or (Deficit)** | **(229)** | **(236)** | **(32)** | **83** | **3** | **(217)** | **(261)** | **(789)** | **(902)** | **(943)** |

| Figure 3-6 | Summer capacity LRB | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| (MW) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
| Coal | 756 | 756 | 756 | 756 | 756 | 756 | 756 | 296 | 296 | 296 |
| Gas | 1,099 | 1,313 | 1,754 | 1,754 | 1,754 | 1,754 | 1,754 | 1,754 | 1,754 | 1,754 |
| Hydro | 1,028 | 1,028 | 970 | 820 | 784 | 637 | 637 | 637 | 562 | 562 |
| Renewables | 57 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 |
| EE | 46 | 90 | 124 | 153 | 177 | 198 | 216 | 233 | 249 | 265 |
| Non-Hydro Contracts | 229 | 213 | 209 | 109 | 109 | 67 | 67 | 9 | 9 | 9 |
| Demand Response | 28 | 35 | 45 | 45 | 45 | 45 | 46 | 49 | 53 | 58 |
| DSG | 97 | 104 | 110 | 116 | 122 | 122 | 122 | 122 | 122 | 122 |
| **Total Resources** | **3,340** | **3,609** | **4,039** | **3,824** | **3,819** | **3,651** | **3,670** | **3,172** | **3,117** | **3,138** |
| **Load and Reserves** | **3,632** | **3,654** | **3,721** | **3,791** | **3,870** | **3,934** | **4,012** | **4,057** | **4,131** | **4,209** |
| **Surplus or (Deficit)** | **(292)** | **(45)** | **318** | **33** | **(51)** | **(283)** | **(341)** | **(885)** | **(1,014)** | **(1,071)** |