Portland General Electric Company
Legal Department
121 SW Salmon Street • 1WTC1301 • Portland, Oregon 97204
Telephone 503-464-8544 • Facsimile 503-464-2200
portlandgeneral.com

Erin E. Apperson
Assistant General Counsel

9/27/2019

Via Electronic mail
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High St SE, Suite 100
P.O. Box 1088
Salem, OR 97301

RE: LC 73 Errata Filing

Portland General Electric Company (PGE) submits for filing Errata to the 2019 Integrated Resource Plan (IRP). Please find a list of these Errata followed by detailed descriptions of each numbered item below. This filing includes updated replacement pages in PDF format. This Errata contains the following revisions:

1. Page 24, Sentences 1-2: corrects a calculation error contributing to the statement "…we held 12 public meetings, which were attended by 221 people online and in person. We received 58 written comments…" In the 2019 IRP, PGE calculated public participation by including the sum of all meeting attendees across all meetings based on the sign-in sheets. We have reconsidered the meaningfulness of this calculation and have provided a revised count. This number reflects the level of participation more appropriately by counting the number of individual people who participated throughout our process rather than the total number of meeting attendees. Page 24, Sentences 1-2 are changed to read: "…more than 91 people participated in our public meetings online or in person. We received 52 written comments…"
2. Figure ES-3: corrects the dollar year representation of the PTC value from 2018 dollars to 2020 dollars and corrects the resulting Net Cost value. This error occurred in the calculations directly supporting this figure, Figure 7-15 (Item 8 below), and Figure 7-16 (Item 9). This error did not influence PGE's resource economic analysis or portfolio analysis.
3. Table ES-3: corrects a typographical error in reference to customer resources, which are originally labeled as "Demand Response". The label is changed to read: "Distributed Flexibility".

4. Figure 3-6: corrects the source data of the image. The original figure included data that was averaged across the years 2020-2050. Figure 3-6 is changed to include only data from the year 2040, as the figure is described in the text on page 79. This update to Figure 3-6 does not impact PGE's analysis.
5. Figure 6-8: corrects the dollar year representation of the PTC value from 2018 dollars to 2020 dollars and corrects the resulting Net Cost value. This error occurred only in the calculations directly supporting this figure and did not influence PGE's resource economic analysis or portfolio analysis.
6. Figure 6-10: corrects a typographical error in the caption to the figure. The caption incorrectly stated "…4-hour batteries…". PGE corrects this to read: "…6-hour batteries…"
7. Table 7-7: corrects a typographical error in reference to customer resources, which are originally labeled as "Demand Response". The label is changed to read: "Distributed Flexibility".
8. Figure 7-15: corrects the dollar year representation of the PTC value from 2018 dollars to 2020 dollars and corrects the resulting Net Cost value. This error did not influence PGE's resource economic analysis or portfolio analysis.
9. Figure 7-16: corrects the dollar year representation of the PTC value from 2018 dollars to 2020 dollars and corrects the resulting Net Power Price Impact. This error did not influence PGE's resource economic analysis or portfolio analysis.
10. Table 8-1: corrects a typographical error in reference to distribution-level resources, which are originally labeled as "Demand Response". The label is changed to read: "Distributed Flexibility".
11. Appendix C, Page 247, Sentence 8: corrects a calculation error contributing to the statement "In total 221 attendees have participated either over the phone or in-person and provided 58 written comments." In the 2019 IRP, PGE calculated public participation by including the sum of all meeting attendees across all meetings based on the sign-in sheets. We have reconsidered the meaningfulness of this calculation and have provided a revised count. This number reflects the level of participation more appropriately by counting the number of individual people who participated throughout our process rather than the total number of meeting attendees. Appendix C, Page 247, Sentence 8 is changed to read: "Over the 17-month public process for the development of the 2019 IRP, more than 91 people participated in our public meetings online or in person and provided 52 written comments."
12. Appendix D, Equation 4: corrects a typographical error in the subscript of the term "β_{15}" of the equation. This term in Appendix D Equation 4 is changed to read: "β_i".

13. Appendix F, Step 2: corrects the description of the second step of the analysis for distributed standby generation (DSG) in the RECAP model. The description is corrected to read: "RECAP was run through 2050 with non-spin requirements included. The difference between the capacity need identified in Step 2 and the capacity need identified in Step 1 was used to estimate the remaining need for standby capacity (expressed as conventional units)." This error occurred only in the description and did not impact analysis.
14. Section I.3.1, Sub-header Additional Items: corrects an internal document link. The sentence reading "See External Study C for the DSG study." changed to read: "See Appendix F for the DSG study."
15. Section I.4.1.1: corrects a typographical error and link reference. The last sentence of the page has an incorrect figure reference and is missing a word. The sentence in Section I.4.1.1 reading "I.4.1.1 the annual available…" changed to read "Figure I-6 shows the annual available…"
16. Figure I-6: corrects a typographical error, which mislabeled the y-axis of the charts. Figure I-6 y-axis labels changed to read: "Available Carbon-Free Generation as a Percent of Load".

Please note that the font used in PGE's 2019 IRP is temporarily unsupported in Adobe Reader. To view PDF files for PGE's 2019 IRP, please open using another application, such as a Chrome browser.

This is being filed by electronic mail with the Filing Center. It is also being served on the LC 73 service list via email only.

If you have any questions, please contact Stefan Brown at (503) 464-7805. Please direct all formal inquiries to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Erin E. Apperson
Assistant General Counsel

encls.

Page 24, Sentences 1-2

Strike Page 24, Sentences 1-2: Over the 17-month public process for the development of the 2019 IRP, ~~we held 12 public meetings, which were attended by 221 people online and in person~~. We received ~~58~~ written comments, five portfolio requests, and hosted our first community listening session to seek feedback from traditionally underrepresented groups that work within the communities we serve.

Replace Page 24, Sentences 1-2 with: Over the 17-month public process for the development of the 2019 IRP, more than 91 people participated in our public meetings online or in person. We received 52 written comments, five portfolio requests, and hosted our first community listening session to seek feedback from traditionally underrepresented groups that work within the communities we serve.

Figure ES-3

FIGURE 6-8: Derivation of net cost of 100 MWa of Washington Wind (2023 COD)

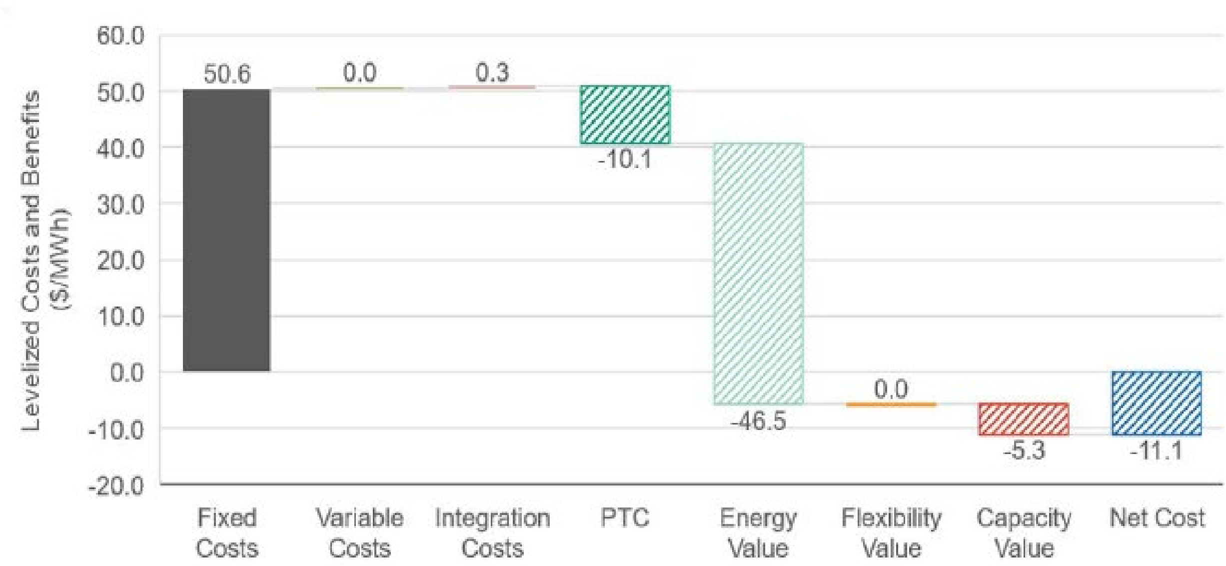


Table ES-3

TABLE ES-3: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

<u>Figure 3-6</u>

FIGURE 3-6: Average month-hour wholesale electricity price heatmaps for the Reference Case and High Renewable WECC Future in the year 2040

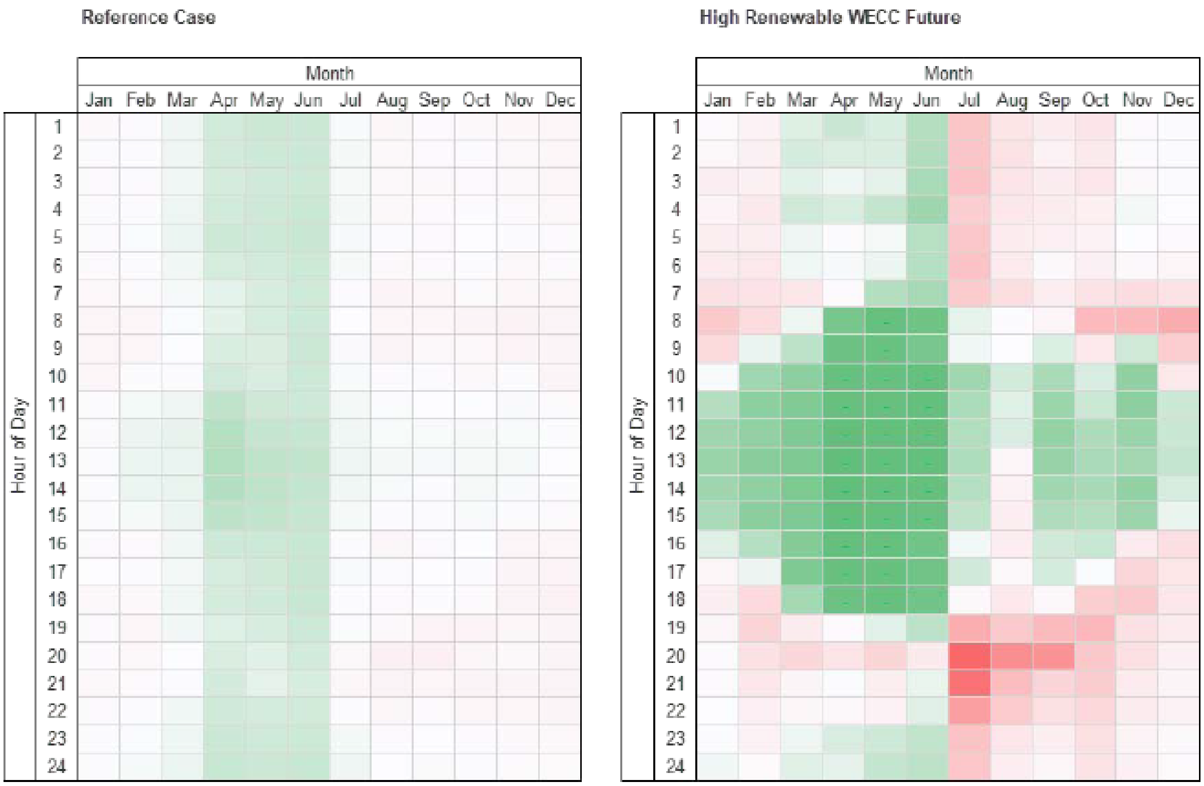
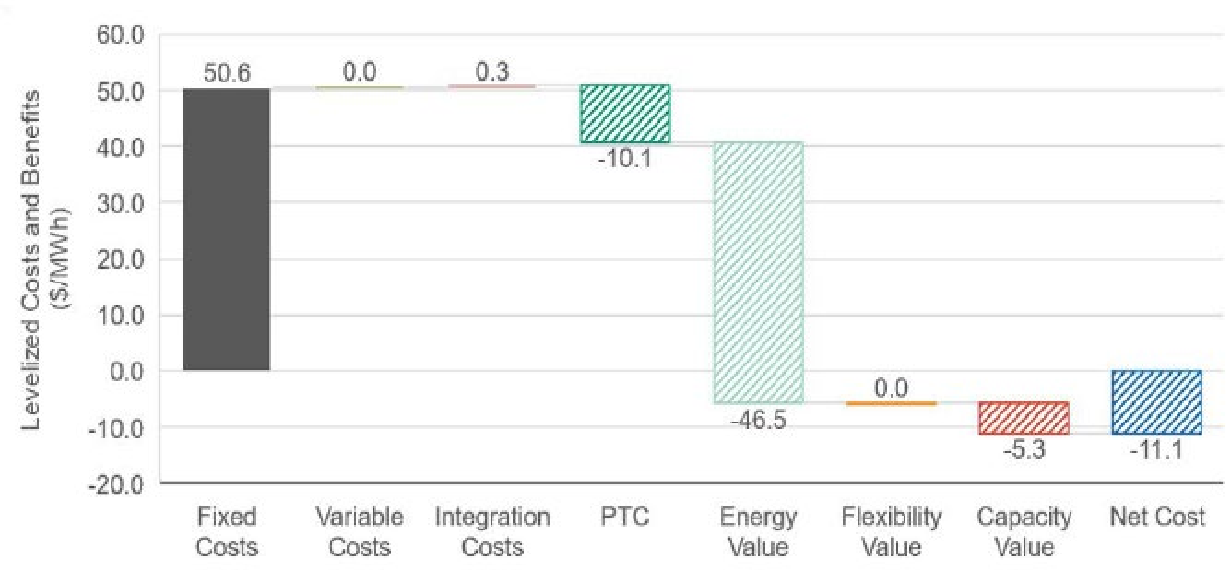


Figure 6-8

FIGURE 6-8: Derivation of net cost of 100 MWa of Washington Wind (2023 COD)



Caption Figure 6-10

Strike caption Figure 6-10 on page 170: Derivation of net cost of 4-hour batteries at 100 MW of capacity contribution (2025 COD)

Replace caption Figure 6-10 on page 170 with: Derivation of net cost of 6-hour batteries at 100 MW of capacity contribution (2025 COD)

Corrected figure shown below.

FIGURE 6-10: Derivation of net cost of 6-hour batteries at 100 MW of capacity contribution (2025 COD)

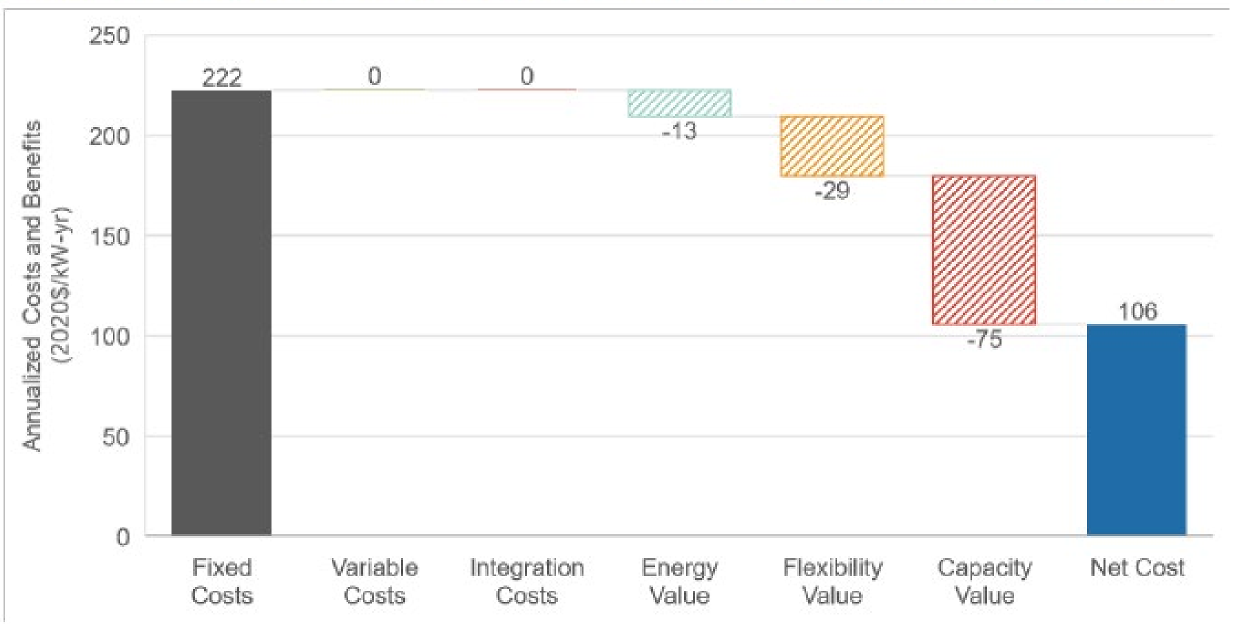


Table 7-7

TABLE 7-7: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

Figure 7-15

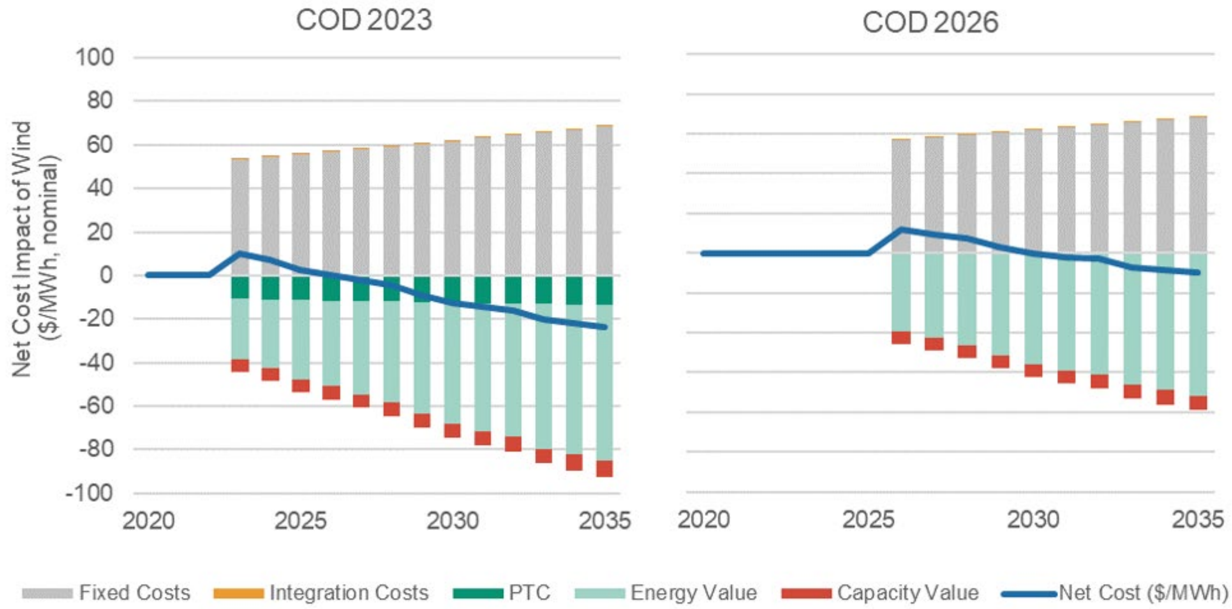

COD 2023
COD 2026
Net Cost Impact of Wind ($/MWh, nominal)
100
80
60
40
20
0
-20
-40
-60
-80
-100
2020
2025
2030
2035
Fixed Costs
Integration Costs
PTC
Energy Value
Capacity Value
Net Cost ($/MWh)

Figure 7-16

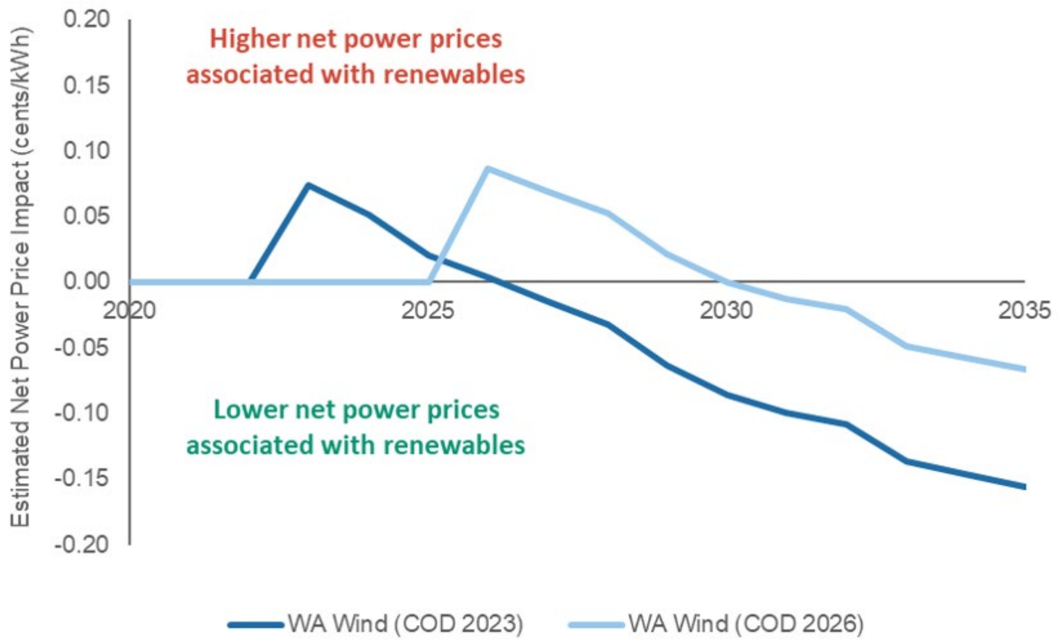

Higher net power prices associated with renewables
Lower net power prices associated with renewables
Estimated Net Power Price Impact (cents/kWh)
0.20
0.15
0.10
0.05
0.00
-0.05
-0.10
-0.15
-0.20
2020
2025
2030
2035
WA Wind (COD 2023)
WA Wind (COD 2026)

Table 8-1

TABLE 8-1: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

Appendix C, Page 247

Strike sentence Appendix C, page 247: ~~In total 221 attendees have participated either over the phone or in-person and provided 58 written comments.~~

Replace sentence Appendix C, page 247 with: Over the 17-month public process for the development of the 2019 IRP, more than 91 people participated in our public meetings online or in person and provided 52 written comments.

Appendix D, Equation 4:

$$\Delta kWh_{com,t} = \sum_{k=0}^{11}(\beta_k Month_k) + \beta_{12}\Delta OENTNA + \beta_{13}\Delta HDD55 + \beta_{14}\Delta CDD60 + \beta_{15}\varepsilon_{t-1} + \sum_{i=1}^{12}(\beta_i \omega_{12}\Delta kWh_{com,t-i}) + \varepsilon_t$$

Appendix F Step 2

Strike sentence Appendix F Step 2 on page 285: RECAP was run through 2050 with ~~the current DSG resources included, non-spin requirements included, and additional active capacity resource included based on Step 1. RECAP determined the remaining standby capacity needed (expressed as conventional units) to achieve the 2.4 hr/yr reliability metric.~~

Replace sentence Appendix F Step 2 on page 285 with: RECAP was run through 2050 with non-spin requirements included. The difference between the capacity need identified in Step 2 and the capacity need identified in Step 1 was used to estimate the remaining need for standby capacity (expressed as conventional units).

Section I.3.1, Sub-header Additional Items

Strike sentence Section I.3.1, Sub-header Additional Items on page 345: See ~~External Study C~~ for the DSG study.

Replace sentence Section I.3.1, Sub-header Additional Items on page 345 with: See Appendix F for the DSG study.

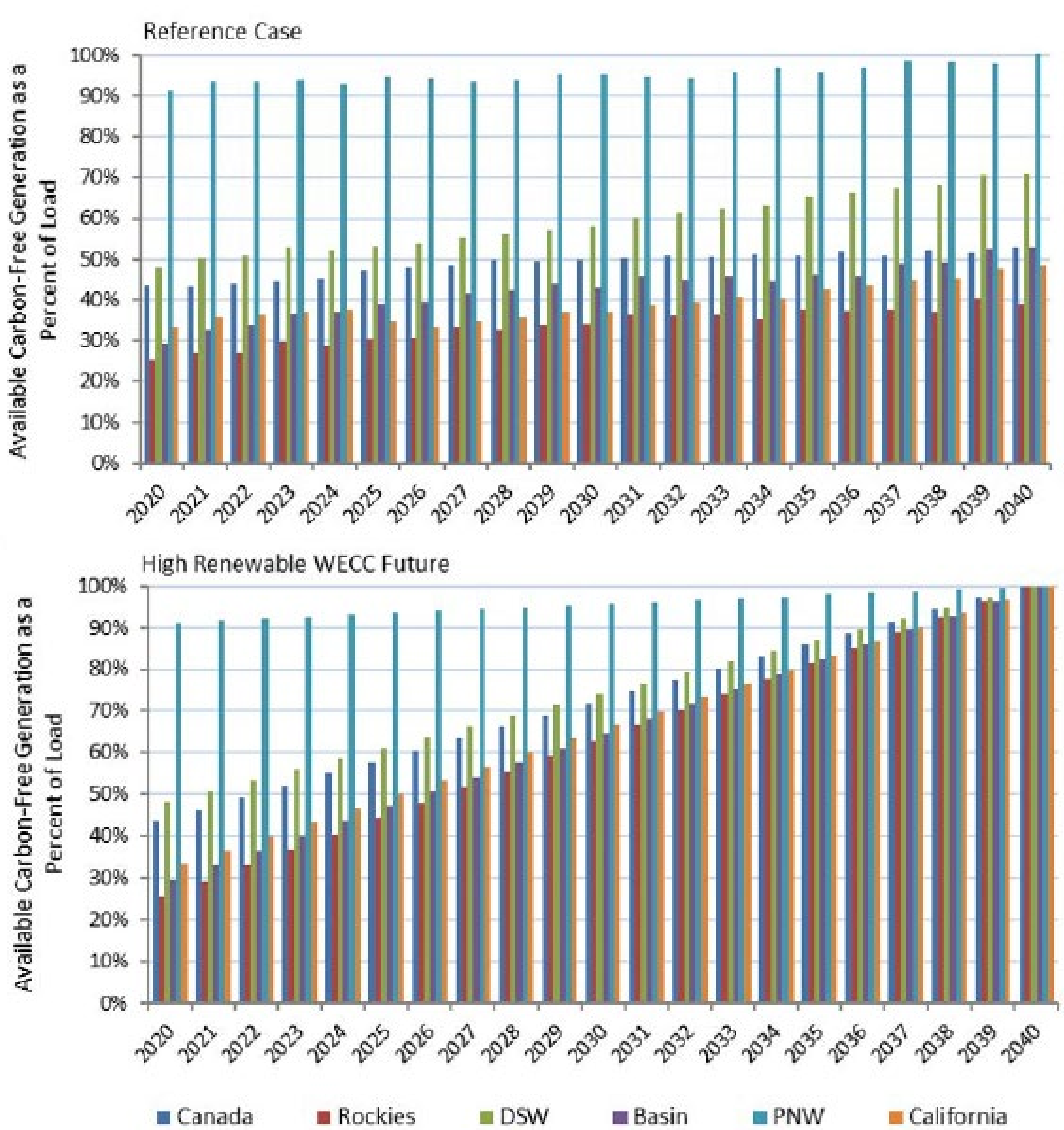
Section I.4.1.1

Strike sentence Section I.4.1.1 on page 351: ~~I.4.1.1~~ the annual available carbon-free generation as a percentage of load by region in the Reference Case and the High Renewable WECC Future.

Replace sentence Section I.4.1.1 on page 351 with: Figure I-6 shows the annual available carbon-free generation as a percentage of load by region in the Reference Case and the High Renewable WECC Future.

Figure I-6

FIGURE I-6: Annual available carbon-free generation as a percent of load per aggregate region through 2040 in the Reference Case and High Renewable WECC Future



Over the 17-month public process for the development of the 2019 IRP, more than 91 people participated in our public meetings online or in person. We received 52 written comments, five portfolio requests, and hosted our first community listening session to seek feedback from traditionally underrepresented groups that work within the communities we serve. We are grateful to everyone who chose to participate in our public process and hope those who participated will see their vital feedback reflected in our plan. While we received generally positive feedback about our efforts to engage stakeholders that traditionally participate in our process, we were much less successful in bringing new perspectives into our process. This will be an area of continued focus for PGE as we work to engage the communities we serve in our planning and decision-making processes.

To address both the evolving energy landscape and the feedback that we heard throughout our process, we designed and implemented the 2019 IRP with a focus on four key themes: decarbonization; customer decisions; uncertainty and optionality; and technology integration and flexibility. These themes encompass some of the most pressing questions facing our industry today and in the coming decades.

- **Decarbonization.** We are committed to enabling local transformation to a clean energy economy. By 2050, we will reduce our greenhouse gas (GHG) emissions by more than 80 percent and help decarbonize other sectors in the economy by enabling the adoption of new clean electric technologies, like EVs. To support these goals, we considered decarbonization and the clean energy transition through several new innovative analyses within the IRP, including our Decarbonization Study[2] and related Decarbonization Scenario,[3] carbon pricing reflective of a potential cap and trade program in Oregon,[4] a scoring metric reflecting portfolio performance in a carbon-constrained future,[5] and incorporation of market-based EV forecasts throughout our analysis.[6] These components of our plan help to ensure that PGE will continue to drive GHGs out of our energy economy and that we will be well positioned to serve our customers in a clean energy future.
- **Customer decisions.** Increasingly, customer decisions around their energy use and the source of their energy are impacting the electricity sector, including long-term planning. In the 2019 IRP, we address customer decisions through a comprehensive study (the Navigant "DER Study") of customer adoption of DERs and customer participation in distributed flexibility programs (including demand response and dispatchable customer storage).[7] We also tested sensitivities related to customer participation in voluntary renewable programs.[8] Our goal in these exercises is to ensure that our plans are robust across a range of potential customer

2 The Decarbonization Study can be found in External Study A. Deep Decarbonization Study.

3 See Section 7.4.1 Decarbonization Scenario.

4 See Section 3.2.2 Carbon Prices.

5 See Section 7.2.1 Scoring Metrics.

6 See Section 4.1.3.1 Electric Vehicles.

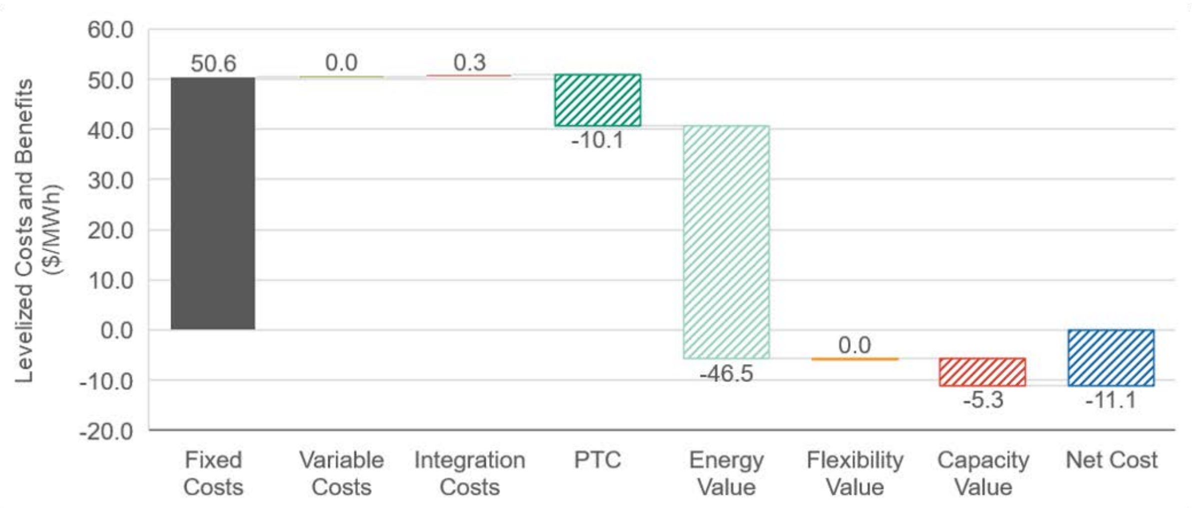
7 Information from the DER Study is referenced in Chapter 4. Resource Needs and Chapter 5. Resource Options. The study can be found in External Study C. Distributed Energy Resource Study.

8 See Section 4.7.2 Voluntary Renewable Program Sensitivities.

The levelized costs also highlight the benefits of near-term renewable action to qualify for federal tax credits. Wind projects that come online by December 31, 2022[13] may qualify for the federal production tax credit (PTC) at the 60 percent level. The PTC steps down to the 40 percent level for projects that come online the following year and then goes away. At the 60 percent level, we find that the PTC lowers the cost of wind by approximately 20 percent, providing an incentive of about $170 million to pursue 150 MWa of wind in the near-term, rather than waiting until 2025 or later. The federal investment tax credit (ITC) provides a similar incentive for solar. The ITC scales down from 30 percent to 10 percent for projects that come online after December 31, 2023.[14] We estimate that the availability of the 30 percent ITC reduces the cost of solar and solar plus storage by approximately 16 percent relative to the 10 percent ITC, providing an additional incentive to acquire renewable resources prior to 2025.

In addition to cost, we analyzed the various benefits that renewable resources bring to the system and compared them to alternative ways of meeting customer needs. We found that by helping to meet both our energy and capacity needs, wind resources are expected to bring more benefits than costs over their lifetime (see Figure ES-3). In the Reference Case, a 150 MWa Washington Wind resource that qualifies for the 60 percent PTC saves about $180 million over its lifetime relative to a strategy of relying on the market for energy and a simple-cycle combustion turbine for an equivalent amount of capacity.

FIGURE ES-3: Costs and benefits of Washington Wind resource that comes online by December 31, 2022



While the long-term benefits of pursuing near-term renewables are compelling, our stakeholders have raised questions about whether today's customers should be paying for resources that will benefit customers in future years. To address this question of intergenerational equity, we estimated

13 Our analysis considers such a project to have a 2023 online date.

14 These projects come online in 2025 in our analysis because we assume that projects that would come online in 2024 would be accelerated to December 31, 2023 to qualify for the higher level of tax incentive.

between 238 and 299 MW in the portfolios that include storage and between 279 MW and 347 MW in the portfolios that add thermal units. Remaining capacity needs are met with the Capacity Fill resource described in Section 7.1.1.1 Resource Adequacy.

We designed an additional portfolio, the Mixed Full Clean portfolio, to capture the most common elements across the best performing portfolios. The Mixed Full Clean portfolio met all of the screening criteria and performed among the best performing portfolios on the basis of the traditional cost and risk metrics—making it our preferred portfolio. In this portfolio, we meet our resource needs (after accounting for DERs and potential capacity contracts) with a combination of renewable resources and energy storage. Specifically, we add 150 MWa of additional wind in 2023 that qualifies for the 60 percent PTC and approximately 250 MW of energy storage by 2025 that has a duration of at least six hours. Table ES-3, Table ES-4, and Table ES-5 summarize the cumulative components of the preferred portfolio in more detail.

TABLE ES-3: Cumulative customer resource additions in the preferred portfolio

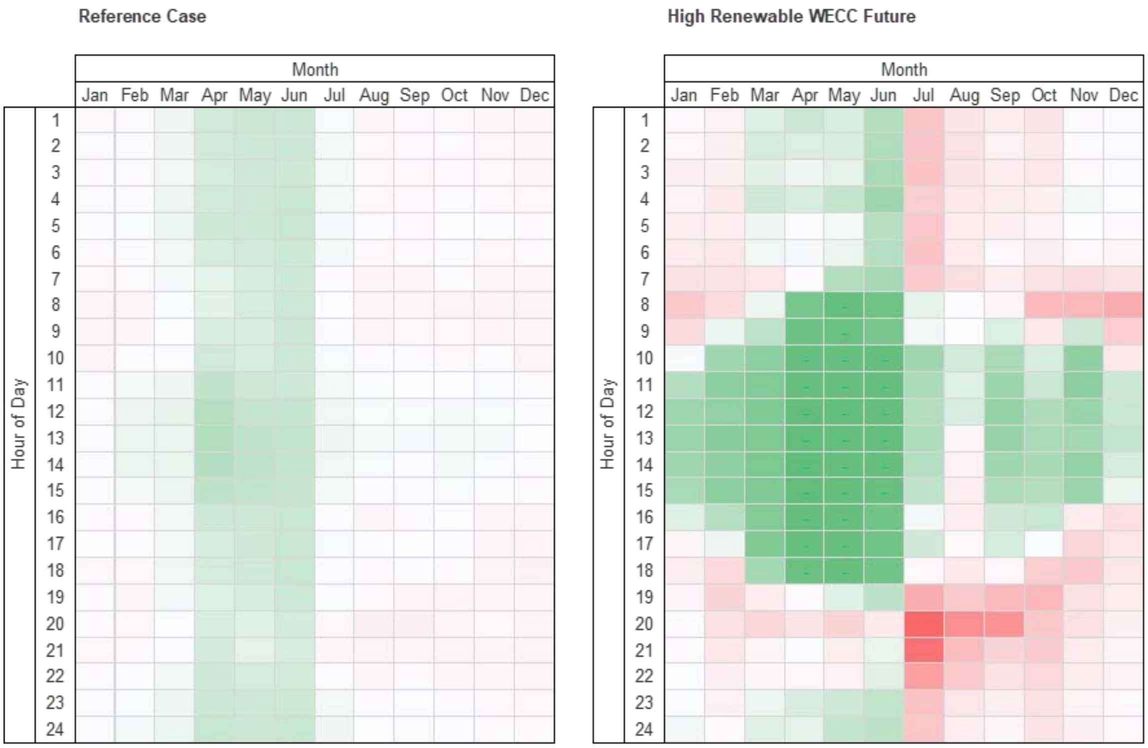
	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

TABLE ES-4: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

FIGURE 3-6: Average month-hour wholesale electricity price heatmaps for the Reference Case and High Renewable WECC Future in the year 2040



In the development of the market price futures that ultimately inform PGE's risk metrics, PGE considered the High Renewable WECC Future in combination with the Gas and Carbon Price Futures and hydro conditions. In addition, the High Renewable WECC Future also flows into the High Tech Future scoring metric described in Section 7.2.1 Scoring Metrics.

3.2.4 Pacific Northwest Hydro Conditions

Hydro generation in the Pacific Northwest strongly influences electricity prices. In the 2016 IRP, PGE considered one hydro condition (reference) across the gas and carbon forecasts and examined critical hydro conditions under reference gas and carbon prices. PGE expanded the treatment of hydro conditions in the 2016 IRP Update by considering three hydro conditions across the gas and carbon cases, and retained this methodology for the 2019 IRP. The low and high hydro conditions were modeled as +/- 10 percent (approximately one standard deviation) of annual Pacific Northwest energy production compared to reference.

Low and High Hydro Conditions were included in the analysis of portfolio performance across risk metrics. They were not considered in portfolio construction.

3.2.5 Electricity Market Price Futures

Consideration of the electricity market price drivers described in the previous sections resulted in 54 distinct hourly price streams for each year through 2050. Figure 3-7 shows the average annual prices across the 54 Market Price Futures.

FIGURE 6-8: Derivation of net cost of 100 MWa of Washington Wind (2023 COD)

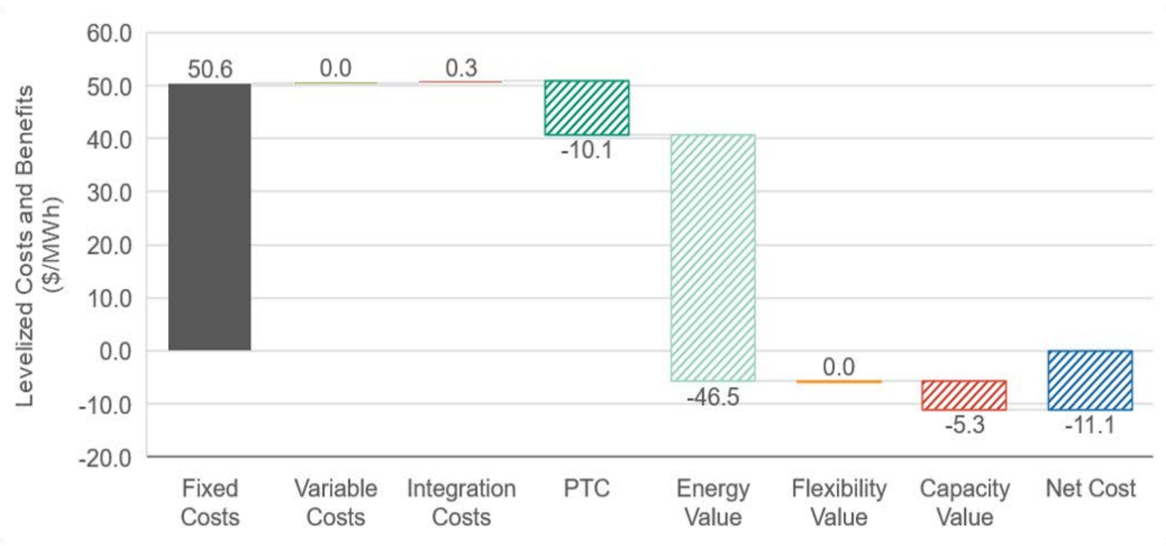
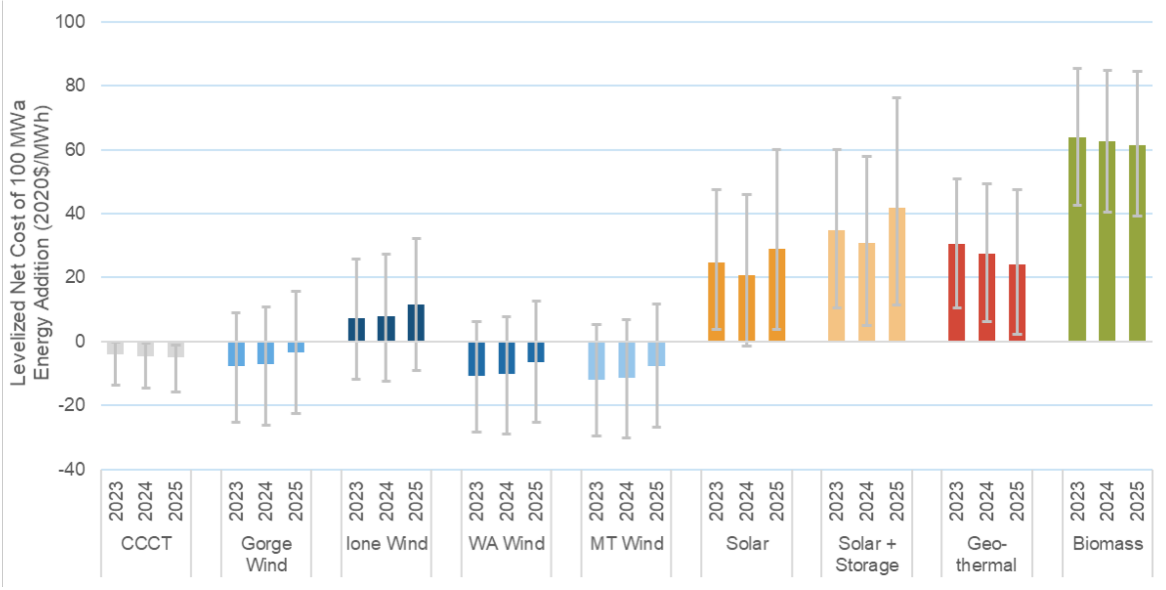
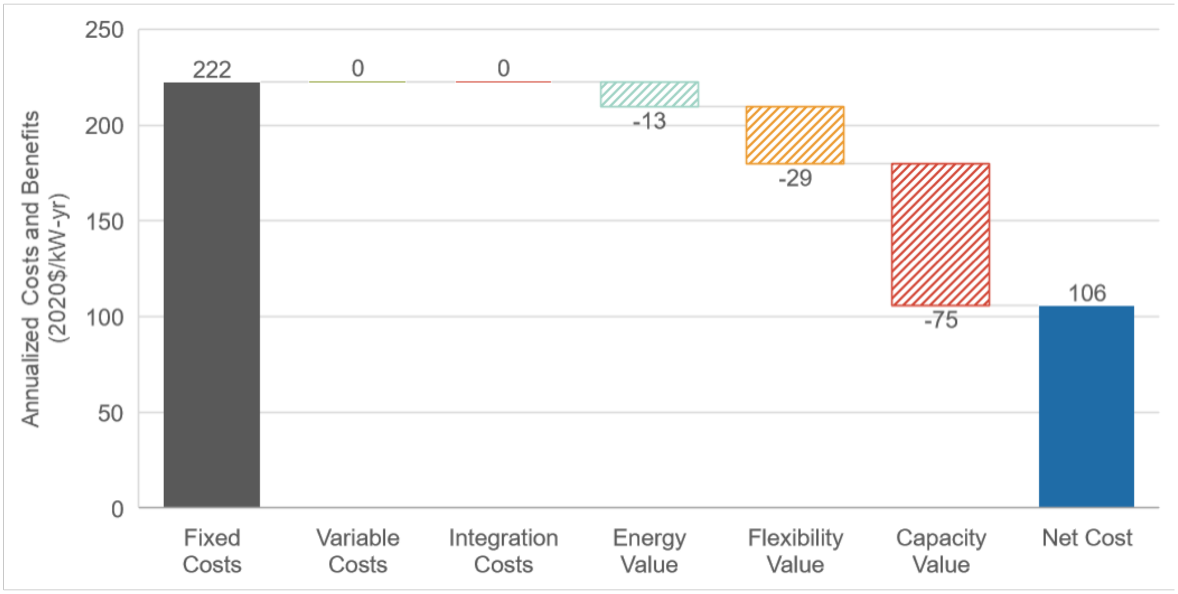


FIGURE 6-9: Net costs of energy resource options by COD



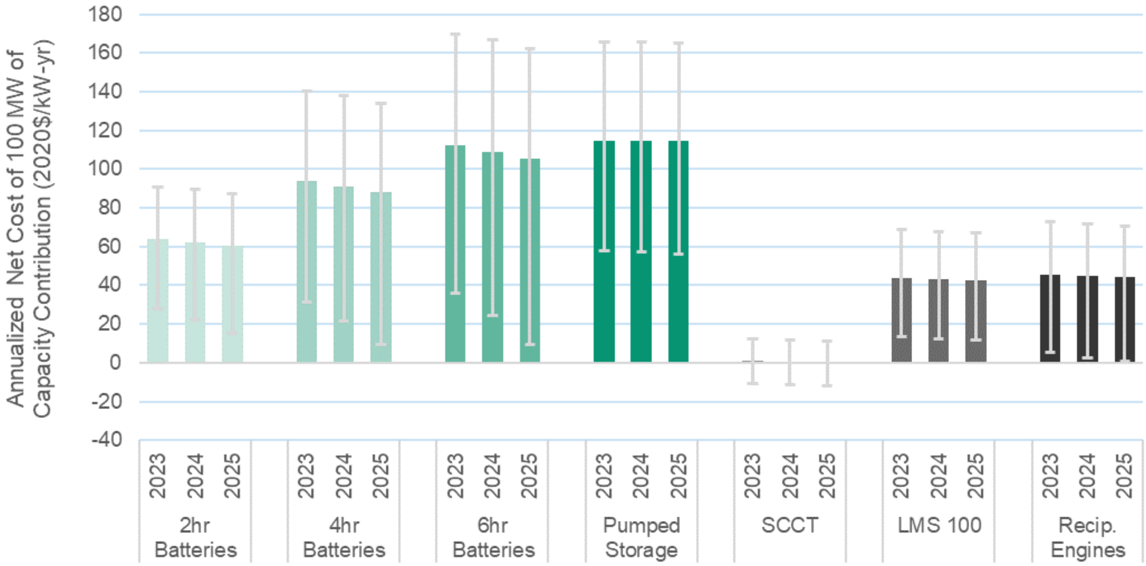
The derivation of net costs is also shown for a capacity resource (a 6-hour battery) under Reference Case conditions in Figure 6-10. The 6-hour battery has a positive net cost ($106/kW-yr) because the sum of its anticipated annualized energy value, flexibility value, and capacity value does not outweigh its annualized fixed costs. In other words, the net cost analysis identifies a $106/kW-yr premium for securing 100 MW of capacity from 6-hour batteries rather than the proxy capacity resource (an SCCT) under Reference Case conditions.

FIGURE 6-10: Derivation of net cost of 6-hour batteries at 100 MW of capacity contribution (2025 COD)



The annualized net costs across the capacity resource options are shown in Figure 6-11. The net costs reflect the value of each resource if enough of the resource is added to the portfolio to provide 100 MW of capacity contribution. The error bars indicate uncertainties in fixed and variable costs as well as energy value.

FIGURE 6-11: Net costs of capacity resource options by COD



The net cost analysis highlights the high degree of uncertainty in resource economics for capacity resources. While the net cost of batteries is considerably higher than the SCCT in the Reference Case, the bounds of uncertainty encompass a scenario in which 4-hour batteries and 6-hour batteries are cost-competitive relative to an SCCT by 2025. The futures in which batteries are more costselected in the Mixed Full Clean portfolio and the resulting portfolio performance are summarized in the following section.

7.3 Preferred Portfolio

The near-term additions in the Mixed Full Clean portfolio are shown in Figure 7-12. Table 7-7 through Table 7-9 provide the complete list of resources encompassed within the Mixed Full Clean portfolio in each of the Need Futures, including customer resources.

FIGURE 7-12: Near-term additions in the preferred portfolio

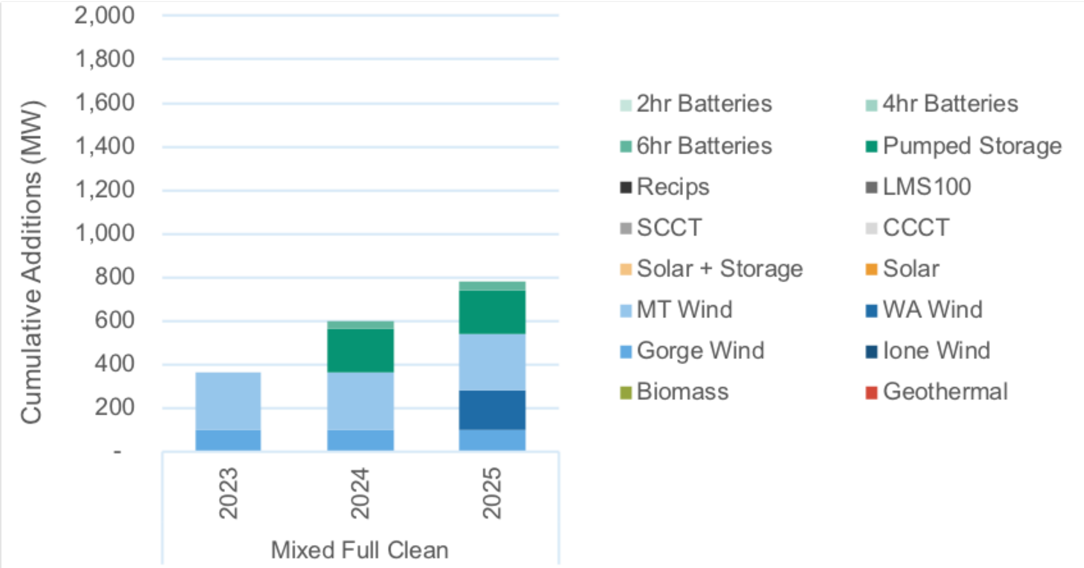


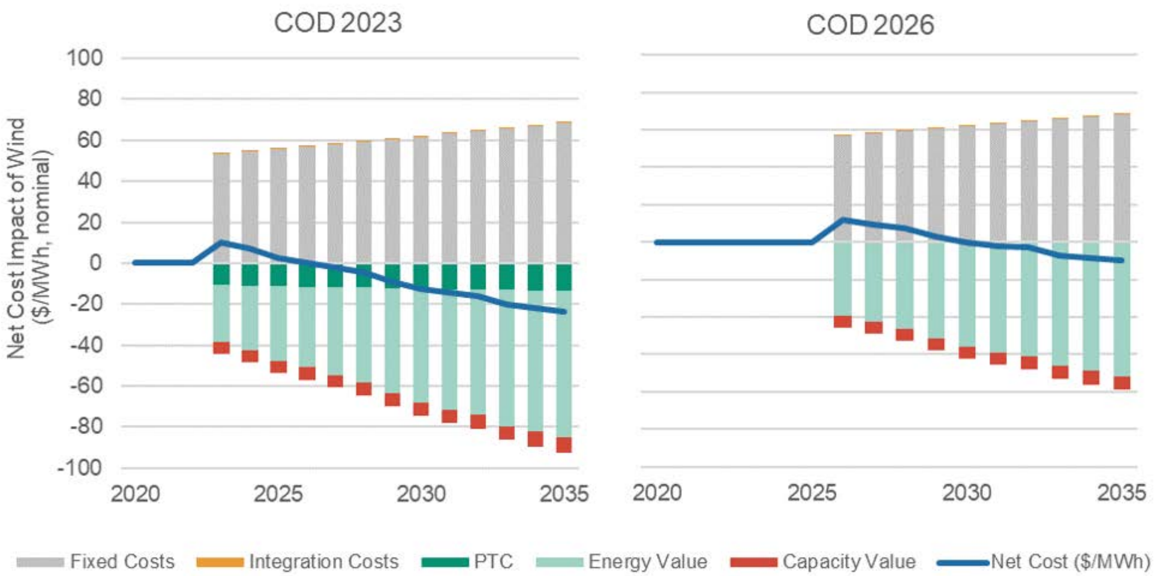
TABLE 7-7: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

While the long-term benefits of pursuing near-term renewables are compelling, some stakeholders have raised questions about whether today's customers should be paying for resources that will benefit customers in future years. To address this question of intergenerational equity, we estimated the potential average impact to power prices between 2021 and 2035 of pursuing renewables in the near term. This analysis explored the expected annual costs and benefits over time of a renewable addition size consistent with the preferred portfolio (150 MWa of Washington Wind with COD 2023 to qualify for the 60-percent PTC) and the same sized renewable addition in 2026. Both additions were effectively modeled as PPAs with prices that escalate with inflation. In other words, fixed costs and PTC impacts were levelized over the life of the project. The resulting annual net cost impacts for the additions (in $/MWh generated) are summarized in Figure 7-15.

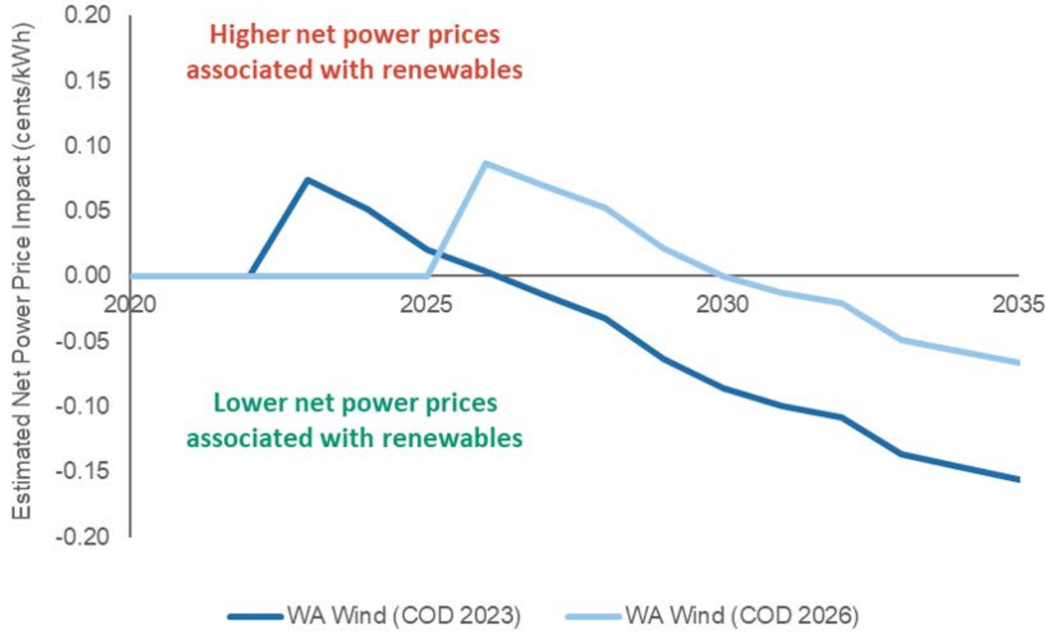
FIGURE 7-15: Annual net cost impact of Washington Wind additions



To estimate the annual net impacts to retail power prices associated with the renewable additions (in cents per kWh of sales), the resulting net costs were scaled up to the resource addition size of 150 MWa and divided by the retail sales forecast in each year. This analysis, which is shown for each year and each renewable addition in Figure 7-16, demonstrates that renewable action is expected to cause a small net increase in power prices in the first years of a project, but that the availability of the PTC decreases the magnitude of these increases, shortens the period over which the increases are expected, and results in larger net reductions to power prices sooner, relative to deferring renewable action.

More specifically, the analysis indicates that pursuing near-term wind is expected to cause a small net increase in average power prices between 2023 and 2026 (approximately 0.04 cents/kWh) but is expected to lower rates beginning in 2027, relative to a strategy of meeting customer energy and capacity needs without the renewable addition. Waiting until 2026 for the same wind addition would result in slightly larger estimated power price impacts due to the unavailability of federal tax credits (averaging approximately 0.05 cents/kWh between 2026 and 2030) and would not result in net reductions to power prices until 2031. The exact impacts to rates and timing of these impacts will depend on the cost, performance, and ownership structure of acquired resources, as well as future market conditions.

FIGURE 7-16: Estimated net impacts to retail power prices of Washington Wind additions



7.3.2 Contribution to Meeting Needs

The Mixed Full Clean portfolio will allow PGE to address near-term needs while providing adequate flexibility to respond as conditions evolve in the future. Figure 7-17 shows how the Mixed Full Clean portfolio meets PGE's energy and capacity needs in 2025. The Mixed Full Clean portfolio adds new long-term resources to meet just under 50 percent of PGE's total capacity needs in 2025 in the Reference Case, with the remainder of needs assumed to be met through other means, including, but not limited to contracts for capacity from existing resources in the region. Of the capacity added from new resource additions, approximately half is provided by new renewables and the rest is provided by energy storage. The new renewable and storage resource additions in the preferred portfolio meet approximately 40 percent of the Reference Case energy shortage in 2025, leaving 60 percent of the energy shortage to be served by other means. In the IRP, this portion of our energy needs are met by market purchases, but other resources could contribute to meeting these needs, including, but not limited to energy associated with additional contracts or customer participation in voluntary renewable programs. The preferred portfolio provides adequate flexibility in energy and capacity needs to accommodate resource needs that are lower than expected, as demonstrated by the Low Capacity Need and 10th Percentile Energy Shortage lines in Figure 7-17.[177] However, additional resources could be required to meet needs that are higher than expected, as shown by the High Capacity Need and 90th Percentile Energy Shortage lines in Figure 7-17.

[177] Distributed Flexibility encompasses all existing and incremental demand response, dispatchable customer storage, and dispatchable standby generation in the Reference Case. It appears below the axis because these resources are already accounted for in the determination of the identified capacity needs.

8.1 Key Elements of the Preferred Portfolio

The Mixed Full Clean portfolio, PGE's preferred portfolio, meets customer needs through three types of actions described below:

- **Customer Actions.** The Mixed Full Clean portfolio incorporates all cost-effective energy efficiency and forecasts for customer participation in a broad suite of demand response and dispatchable customer resource programs. Table 8-1 summarizes the impact of these actions.

TABLE 8-1: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Distributed Flexibility†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

- **Renewable Actions.** The Mixed Full Clean portfolio incorporates a 150 MWa renewable addition in 2023. This addition allows us to leverage federal tax credits to secure low-cost renewables to meet our near-term energy and capacity needs while making steady progress toward meeting long-term RPS needs and GHG goals. Table 8-2 summarizes renewable additions in the preferred portfolio.

TABLE 8-2: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

Appendix C. 2019 IRP Public Meeting Agendas

PGE manages IRP development through a collaborative, interactive process with an active customer and public stakeholder group. All IRP meetings are open to the public and are hosted at least once per quarter. Before we began work on the 2019 IRP, we engaged stakeholders in a conversation around values. We heard that affordability, sustainability, and transparency are paramount to many of our stakeholders as they engage in the IRP process. We kept those values in mind throughout our process and took tangible steps to improve our process to be responsive to what we heard. Specifically, we shared draft information more frequently as the analysis unfolded; we requested feedback on specific design questions; we invited stakeholders to submit informal comments throughout the process; and we modeled specific portfolios requested by stakeholders. In the process of creating the 2019 IRP PGE hosted thirteen roundtable and technical meetings. Over the 17-month public process for the development of the 2019 IRP, more than 91 people participated in our public meetings online or in person and provided 52 written comments. Public stakeholders had opportunity to submit comments anytime during IRP development via email, over the phone, or at meetings. As we moved through analysis for the 2019 IRP, PGE specifically requested stakeholders submit portfolios to be included in the 2019 modeling considerations; five unique portfolio requests were received. This feedback helped inform our resource plan.

PGE makes all meeting materials available on the IRP webpage and advertises public meeting dates there as well. The interests and values shared with us are incorporated into our final IRP and a summary of the comments we received are posted to our 2019 IRP webpage.

This summary of our meeting dates and topics hosted in support of the 2019 IRP are a simplified snapshot of the dedication of a group of individuals from the community who have put in time to advocate for their communities and to educate us. We have attempted to incorporate what we have heard and plan to continue to engage and evolve through this 2019 IRP and into future IRP development.

August 24, 2017, Roundtable 17-3

- Resource Cost Studies Update
- Resource Cost & Levelization
- Scoring Metrics Discussion
- Decarbonization Study
- IRP Scheduling/Planning

February 14, 2018, Roundtable 18-1 (Day 1 – 2019 IRP Kickoff)

- 2019 IRP
- Portfolio Construction
- Futures and Uncertainties
- Flexibility Assessment Methodology
- Decarbonization Study

EQUATION 3: Residential customer count

$$\Delta^2 CC_{res,t} = \beta_0 + \beta_1 \times \Delta^2 POP_{OR} + \epsilon_t$$

Where:

- $\Delta^2 y = (y_t - y_{t-1}) - (y_{t-1} - y_{t-2})$, representing a second-order difference
- POP_{OR} = Oregon population
- ε_t = error term

D.1.3.2 Commercial Model

The commercial energy deliveries model, shown in Equation 4, is a monthly model that establishes a relationship of commercial energy deliveries to Oregon total non-farm employment and heating and cooling degree days.

EQUATION 4: Commercial energy deliveries

$$\Delta kWh_{com,t} = \sum_{k=0}^{11}(\beta_k Month_k) + \beta_{12}\Delta OENTNA + \beta_{13}\Delta HDD55 + \beta_{14}\Delta CDD60 + \beta_{15}\varepsilon_{t-1} + \sum_{i=1}^{12}(\beta_i \omega_{12} \Delta kWh_{com,t-i}) + \varepsilon_t$$

Where:

- $\Delta y = (y_t - y_{t-1})$, representing a first-order difference
- OENTNA = Oregon total non-farm employment
- HDD55 = Heating degree day with 55° F setpoint
- CDD60 = Cooling degree day with 60° F setpoint
- ε_t = error term

D.1.3.3 Industrial Model

The industrial model is a monthly model that includes gross domestic product as a driver of energy deliveries (Equation 5).

EQUATION 5: Industrial energy deliveries

$$\Delta kWh_{ind,t} = \sum_{k=0}^{11}(\beta_k Month_k) + \beta_{12}\Delta GDPR + \beta_{13}\Delta kWh_{ind,t-1} + \beta_{14}\varepsilon_{t-1} + \varepsilon_t$$

APPENDIX F. Dispatchable Standby Generation Study

PGE's Dispatchable Standby Generation (DSG) program offers access to a fleet of customer-located diesel generators that provide non-spinning reserves to PGE's system. A summary of the existing program is provided in Appendix E. Existing and Contracted Resources and a detailed discussion of the program was provided in Section 7.14 of PGE's 2016 IRP.[205]

In the 2019 IRP Action Plan (Chapter 8), PGE recommends continued expansion of the DSG fleet as a cost-effect action to meet the system's non-spin needs. In order to assess future megawatts of DSG needed, PGE performed a DSG study using the same methodology as used by Energy + Environmental Economics, Inc. (E3) in the 2016 IRP.

As discussed in Section 4.3 Capacity Adequacy, PGE's capacity adequacy assessment is based on an adequacy measure of the ability to serve the hourly load plus required operating reserves (spinning and non-spin). For the DSG study, PGE used a two-step Renewable Energy Capacity Plannig (RECAP) process to separate the "standby" capacity need (non-spin) from the "active" capacity need (load and spin) for the Reference Need Future:

1. RECAP was run through 2050 with the current DSG resources excluded and non-spin requirements removed. RECAP determined the capacity needed to achieve the annual reliability metric for each year (2.4 hours per year). This determined the need for active capacity, expressed as conventional units (defined as 100-MW units with a five percent forced outage rate).
2. RECAP was run through 2050 with non-spin requirements included. The difference between the capacity need identified in Step 2 and the capacity need identified in Step 1 was used to estimate the remaining need for standby capacity (expressed as conventional units).

PGE converted the conventional units to the equivalent DSG capacity to calculate the targeted fleet capacity for 2021-2050. Table F-1 illustrates the current DSG fleet capacity,[206] the targeted total fleet capacity, and the fleet deficit. The Action Plan (discussed in Chapter 8) includes DSG actions to meet the targeted DSG fleet capacity.

TABLE F-1: DSG fleet capacity, MW (meter)

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Current Fleet Capacity	128	128	128	128	128	128	128	128	128	128
Targeted Fleet Capacity	**134**	**134**	**136**	**137**	**137**	**142**	**149**	**156**	**161**	**166**
Deficit (Target - Current)	6	6	9	9	9	14	22	28	33	38

[205] See PGE's 2016 Integrated Resource Plan, Volume 1, Section 7.1.4 (filed Nov. 15, 2016).

[206] As of December 2018.

Hydro

The Clackamas, Pelton, and Round Butte projects were modeled with the same monthly sustained maximum capacity values used in the 2016 IRP. For the Company's Mid-C resources, E3 built monthly probability distributions using PGE's monthly dependable capacities, historic hydro conditions, and Northwest Power and Conservation Council (NWPCC or the Council) data relating hydro conditions to peaking capability. Small, run-of river projects and contracts were included with either their monthly average energy, historic generating profile, or no capacity value on a case-by-case basis.

Market Capacity

The market capacity assumptions in RECAP represent the long-term planning assumption for the quantity of capacity available under constrained conditions. For the 2019 IRP, there are low, reference, and high values by season and by on-peak and off-peak hours. The values for winter and summer on-peak hours are based on the regional capacity study prepared for PGE by E3, as discussed in Section 2.4.2.1. E3's study is provided in External Study E. For the spring and fall on-peak hours, the values are based the 2016 IRP assumption of 200 MW (or, if larger, the E3 assumption for summer on-peak). For all seasons, the off-peak assumption is 999 MW.

Utility Storage

Utility-scale battery and pumped hydro storage resources were evaluated in RECAP based on profiles created from an optimization of charge and discharge based on PGE's loss-of-load profile. The optimization was calculated with a program outboard of RECAP.

Additional Items

The following summarizes additional inputs or requirements:

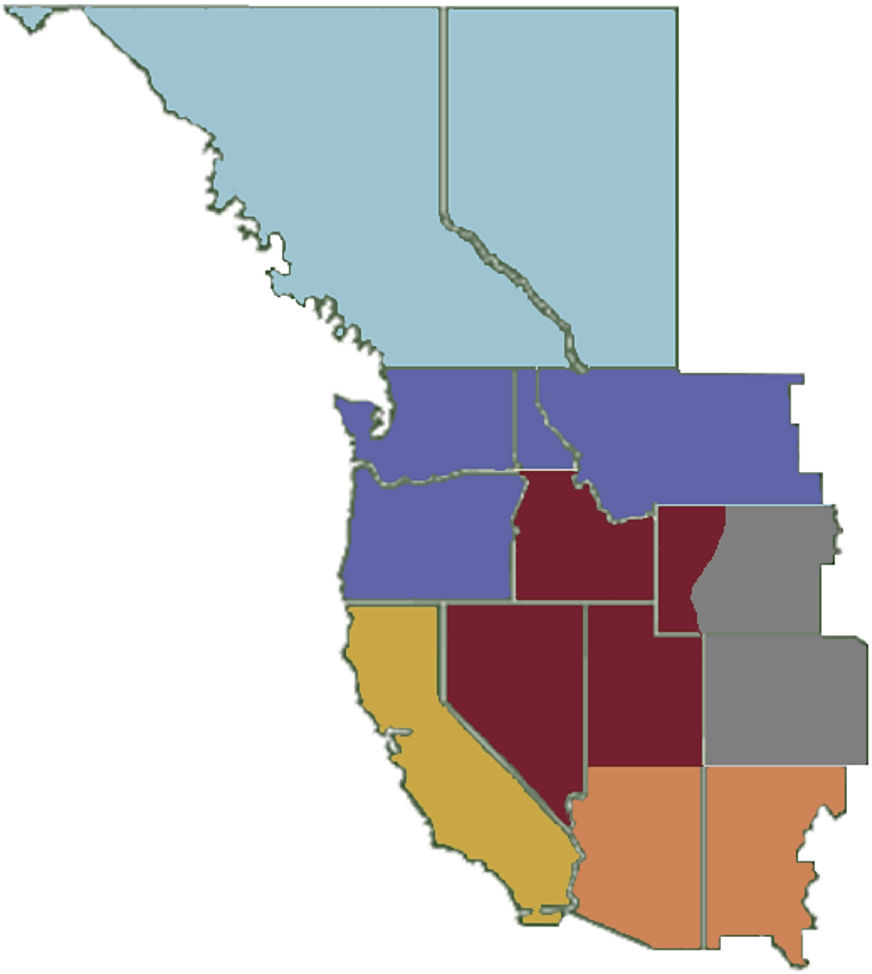
- Thermal resources are represented in RECAP by their capacities associated with monthly average temperatures and forced outage rates.
- Dispatchable standby generation (DSG) resources are represented based on their conventional unit equivalence for the total targeted fleet capacity (existing plus recommended acquisitions). See Appendix F for the DSG study.
- QF contracts reflect those executed as of December 18, 2018.
- Additional executed contracts are modeled based on their resource type and contract terms.
- Operating reserve requirements are based on WECC BAL-002 spinning and supplemental (non-spin) reserves (approximated as six percent of load).

I.3.2 Loss-of-Load Expectation and Capacity Need

From the resource input data described above, RECAP creates a resource probability distribution curve for each month, day-type, and hour. For variable resources, distinct distributions are also generated by load level within each month, day-type, and hour. The model then combines the load and resource distributions via the convolution method to create a distribution representing the probability that the load plus reserves exceeds the available resources (variable, customer side, hydro, thermal, contracts, and market capacity) in each month, day-type, or hour.

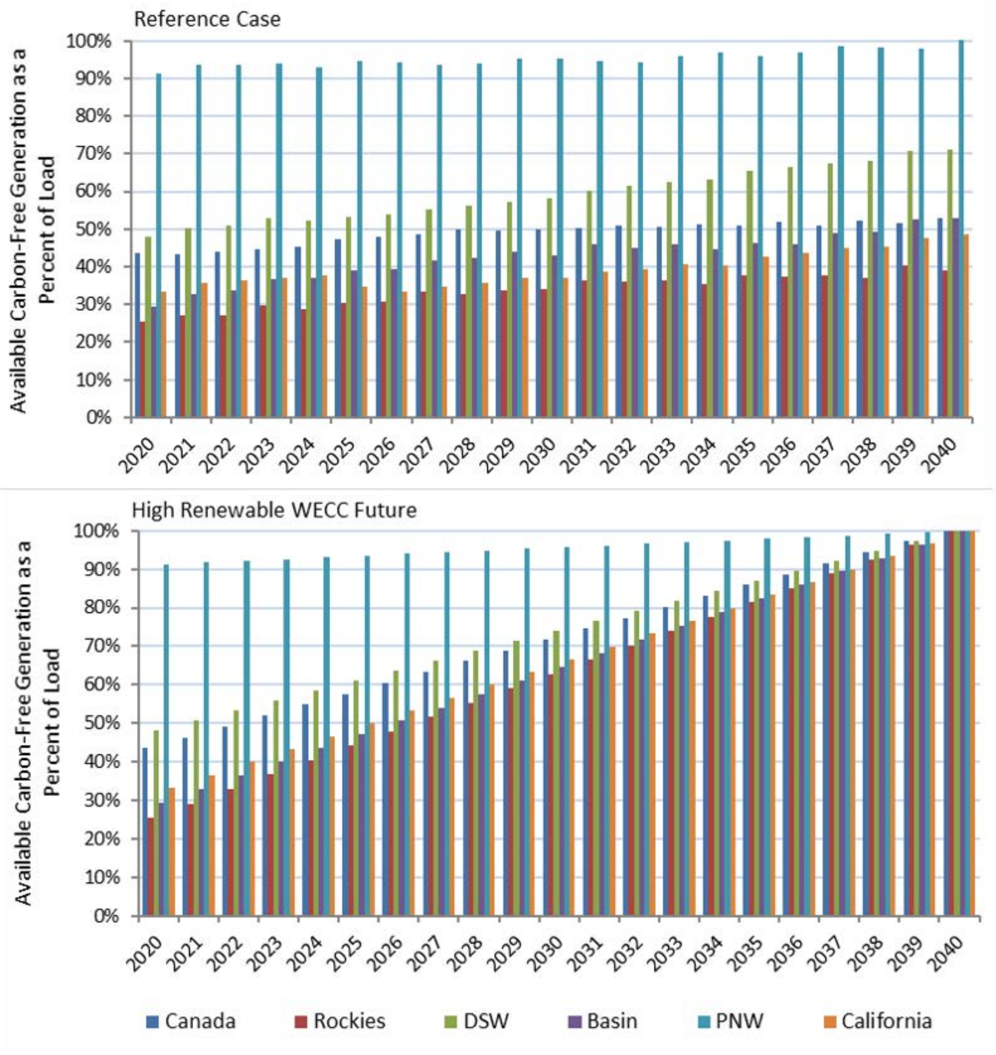
FIGURE I-5: Aurora zone assignments per aggregate WECC region and corresponding color-coded geographical mapping

WoodMac Zone	Region
WECC_Alberta	Canada
WECC_BritishColumbia	Canada
WECC_Montana	PNW
WECC_PNW_IdahoSouthwest	PNW
WECC_PNW_LowerColumbia	PNW
WECC_PNW_OregonWest	PNW
WECC_PNW_Spokane	PNW
WECC_PNW_WashingtonCentral	PNW
WECC_PNW_WashingtonWest	PNW
WECC_Colorado East	Rockies
WECC_Colorado West	Rockies
WECC_Wyoming-RMPA	Rockies
WECC_NevadaNorth	Basin
WECC_NevadaSouth	Basin
WECC_PNW_IdahoEast	Basin
WECC_Utah	Basin
WECC_Wyoming-NWPP	Basin
WECC_BajaNorth	California
WECC_CA_BANCTID	California
WECC_CA_IID	California
WECC_CA_LADWP	California
WECC_CA_PGandE_North	California
WECC_CA_PGandE_ZP26	California
WECC_CA_SCE	California
WECC_CA_SDGE	California
WECC_COB	California
WECC_IPP	California
WECC_Arizona	DSW
WECC_FourCorners	DSW
WECC_NewMexico	DSW
WECC_Palo Verde	DSW



For each aggregate region, the Wood Mackenzie wind and solar additions per year for all represented zones were summed to create regional resource ratios. These ratios were utilized to assign the mix of wind and solar per region in a linear growth trajectory from 2020-2040. For example, the renewable expansion in the region of California had a higher percentage of solar than wind, whereas the PNW region renewable expansion contained a higher percentage of wind than solar. Figure I-6 shows the annual available carbon-free generation as a percentage of load by region in the Reference Case and the High Renewable WECC Future.

FIGURE I-6: Annual available carbon-free generation as a percent of load per aggregate region through 2040 in the Reference Case and High Renewable WECC Future



I.4.1.2 Carbon Pricing

Carbon pricing scenarios were designed to simulate carbon programs in Oregon and Washington beginning in 2021 that, while independent, were modeled as having the same carbon prices as California. As such, carbon pricing reflects the GHG allowance price forecasts provided by the California Energy Commission (CEC) for existing policy. PGE applied the 2017 CEC prices, which were published in January of 2018.[213] The CEC forecasts have been updated since the IRP input data was locked-in. For reference, Figure I-7 below compares the 2017 CEC pricing to the preliminary 2019 prices.[214]

---

[213] Revised 2017 IEPR GHG Price Projections, published 1/16/2018. http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm. 2017 IEPR Deflator Series, using Moody's Analytics, June 2017 GDP Deflator and CPI Forecast.

[214] Preliminary 2019 IEPR GHG Price Projections, published 2/5/2019. Staff Report: Initial Statement of Reasons, September 4, 2018, https://www.arb.ca.gov/regact/2018/capandtrade18/ct18isor.pdf.