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

Erin E. Apperson
Assistant General Counsel
erin.apperson@pgn.com

January 29, 2021

Via Electronic Filing

Oregon Public Utility Commission
Attn: Filing Center
201 High Street Southeast Suite 100
Post Office Box 1088
Salem, Oregon 97301

Re: **LC 73 – Portland General Electronic Company, 2019 Integrated Resource Plan**

Attention Filing Center:

Enclosed for filing in the above-captioned docket is Portland General Electric Company's Integrated Resource Plan (IRP) Update.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Assistant General Counsel

EEA: dm
Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Integrated Resource Plan.	**PORTLAND GENERAL ELECTRIC COMPANY'S** **IRP UPDATE**

Portland General Electric Company (PGE) submits the enclosed 2019 Integrated Resource Plan Update (IRP Update) to the Public Utility Commission of Oregon (OPUC or Commission) pursuant to Commission Order No. 20-152; Guideline 3(f) and 3(g); and Oregon Administrative Rule (OAR) 860-027-0400(8). The IRP Update includes the following items:

- Status updates on acknowledged actions, enabling analyses, and other requirements from OPUC Order No. 20-152;
- Updated load forecast, including customer demand impacts from COVID-19;
- Resource updates for bilateral contracts, PURPA Qualifying Facilities (QF), voluntary renewable programs, and regional capacity;
- Capacity need, energy position, renewable portfolio standard (RPS) position updates, and sensitivities;
- Updated capacity contribution values, notably capturing the impact of a material increase in solar resources in the resource portfolio;

- New capacity adequacy model (Sequoia) with dispatch optimization and process efficiency improvements;
- Updated gas price forecasts, carbon price forecasts, and wholesale electricity market price forecasts;
- Incorporation of all Production Tax Credit (PTC) extensions as of December 27, 2020;
- Interconnection costs; and
- Updated portfolio analysis capturing the updated information.

The IRP Update does not propose any changes to the acknowledged 2019 IRP action plan.

PGE respectfully requests that the Commission acknowledge this IRP Update so that we can include the updated inputs in the May 1 avoided cost update filing. This motion is consistent with PGE's request for acknowledgment of the 2016 IRP Update, which the Commission acknowledged.[1] Allowing PGE to update its avoided costs on May 1 consistent with this IRP Update will allow for greater accuracy in the calculation of avoided costs by using more up-to-date information.

PGE's IRP Update is filed consistent with applicable Commission orders and rules and should be acknowledged so that PGE's avoided cost price update is based on the best available assumptions and forecasts.

Dated this 29th day of January, 2021.

Respectfully submitted,

Erin Apperson, OSB No. 175771
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8544 phone
(503) 464-2200 fax
erin.apperson@pgn.com

[1] See Order No. 18-145.

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1. Introduction

The Oregon Public Utility Commission (OPUC or Commission) acknowledged, with conditions and additional directives, Portland General Electric Company's (PGE or Company) 2019 Integrated Resource Plan (IRP) on March 16, 2020.[2]

An IRP Update addresses specific inputs that may have changed since the most recent IRP was acknowledged, without attempting to fully revise the IRP. This IRP Update refreshes the analysis filed with the 2019 IRP and provides status reports on actions and requirements flowing from the Commission Order. PGE submits this 2019 IRP Update, in compliance with Oregon Administrative Rule (OAR) 860-027-0400(8) and IRP Guidelines 3(f) and 3(g), to inform the Commission of the Company's actions since acknowledgment and provide a more current assessment of key resource needs, costs, and value to customers, among other things. In doing so, we affirmed that the identified path forward remains the best course for our customers even in the face of changes in the environment this year. We do not propose any change to the acknowledged 2019 IRP action plan.

PGE respectfully requests that the Commission acknowledge this IRP Update so we can include the updated inputs in the May 1 avoided cost update filing. This is consistent with PGE's request for acknowledgment of the 2016 IRP Update, which the Commission acknowledged.[3] Allowing PGE to update its avoided costs on May 1 consistent with this IRP Update will allow for greater accuracy in the calculation of avoided costs by using more up-to-date information.

The year since the Commission acknowledged our 2019 IRP has been extraordinarily challenging. Our customers, employees, regulators, and process participants have faced severe tragedies and daily stress due to the COVID-19 pandemic, economic hardship, the ongoing struggle against systemic racial injustice, the worsening climate crisis, and destructive wildfires. The energy industry, already undergoing profound change, is once again adapting to rapidly evolving needs, priorities, operating constraints, and possibilities.

There was positive movement as well. In 2020, Oregon took a significant step forward in addressing the climate crisis with the Governor's Executive Order No. 20-04. At the Federal level there have been extensions to renewable tax credits with potential to further benefit our customers and the environment, the latest arriving as recently as December 27, 2020. PGE also announced its commitment to new and ambitious climate goals that aim to accelerate our progress and achieve companywide net zero greenhouse gas emissions by 2040 and an interim power supply goal of 80% greenhouse gas emissions reduction by 2030.[4]

[2] Order No. 20-152 – available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf.
[3] See Order No. 18-145.
[4] PGE Climate Goals are available at: https://portlandgeneral.com/about/energy-future/climate-goals?_ga=2.25526461.1880550217.1605717397-1462291631.1589305875

PGE is in the unique position to optimize the electric system for customers' benefit as the industry evolves. Reliability and affordability remain the foundation of our role in supporting customers, Oregon's economy, and the overall advancement of society. Integrated resource planning is a key component of our efforts to integrate the delivery of affordable, cost-effective customer choices with our approach to decarbonization and our role of ensuring reliability, resiliency, and access for all through a smarter grid. In this IRP Update, we provide updates on our progress in several areas, including expansion of flexible load resources through accelerated enrollments in current programs, additional offerings around storage and electric vehicles (EVs), and innovative pilots in the Smart Grid Test Bed (**2.1.2 Distributed Flexibility**). We also discuss growing customer participation in our voluntary renewables program offerings (**Section 2.3.7 Voluntary Renewables Programs**).

Additionally, we refreshed our analysis to incorporate recent PTC updates (**6. Portfolio Analysis**) and customer demand impacts from COVID-19 (**3.1.1 Near Term Load Forecast and COVID-19**). We also included a need assessment update, updated long-term load forecast and updated energy position, capacity need, and RPS need (**3.Need and Position Assessments**). We updated short- and long-term natural gas price forecast, carbon price forecast, and the resulting wholesale electricity market price forecasts (**4. Wholesale Market Electricity Prices**). We updated resource costs to include interconnection costs and provided updated capacity contribution values and a refreshed cost of capacity (**5. Resource Economics).** Finally, we provided updated portfolio analysis (**6. Portfolio Analysis).** The 2019 IRP Update does not introduce new methodologies addressing EO 20-04, but PGE looks forward to expanded analysis and methodologies in the 2022 IRP process. Work is already underway to incorporate the OPUC workplan for EO 20-04 into the next IRP and we look forward to working closely with Staff and participants on implementation of the workplan as we develop the 2022 IRP.

While there were many unforeseeable developments marking this past year, we intend this IRP Update to be responsive to those that are essential to assessing the continued reasonableness of the action plan. This update has not resulted in any recommended changes to the acknowledged action plan from the 2019 IRP. We continue to find that the recommended actions are in the long-term interest of our customers, providing the best path forward to ensure system reliability and continued progress toward delivering a clean, affordable, and smart energy future for Oregon.

The Company looks forward to continuing to engage with the Commission and process participants in future meetings, roundtables, and technical forums. The time, extra effort, flexibility, and engagement of our new and long-standing participants and Commission Staff is appreciated and has helped foster and increase the level of engagement we strive for in our public process.

2. Status Reports on Acknowledged Actions and Order Requirements

2.1. Customer Actions

2.1.1. Energy Efficiency

Order No. 20-152 acknowledged PGE's target to acquire all cost-effective energy efficiency (approximately 157 MWa by 2025), with the following modifications agreed to by Staff and PGE and accepted by the Commission.

> Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.
>
> Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.
>
> Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and to consider adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.[5]

PGE provides the following updates:

- PGE and Energy Trust have been coordinating on the development of the next long-term energy efficiency forecast for IRP planning. PGE provided updated avoided cost and load inputs and requested additional forecasts based on load and cost scenarios. Energy Trust planning staff and PGE met in September 2020 to discuss the upcoming forecast, scenarios, and potential methods to incorporate incremental energy efficiency beyond the baseline forecast.

- PGE and Energy Trust have had initial discussions about the Commission's request to hold a workshop on data center energy efficiency opportunities. PGE will work with Energy Trust, Staff, and participants to schedule and hold a workshop before filing the 2022 IRP.

- Energy Trust and PGE are working to acquire all cost-effective and reasonable energy efficiency and will continue to monitor potential impacts from COVID-19 on near-term energy efficiency acquisitions. An updated long-term energy efficiency forecast will be incorporated in the 2022 IRP.

[5] Order No. 20-152 at 22.

2.1.2. Distributed Flexibility

Distributed Flexibility (or Flexible load) is a cornerstone of PGE's commitment to decarbonization while maintaining reliability and affordability. Flexible load can provide a range of essential grid services and it can help PGE meet the challenges of supporting a future where variable renewable resources provide the bulk of the energy supply. Additionally, if designed with the customer in mind, flexible load programs can address issues of equity and environmental justice. Through our pilots, programs, new web platform, and our digital consumer roadmap, PGE is exploring new ways of improving the customer experience, maximizing participation, and integrating resources effectively into operations.

As customer and communications technologies advance and economics improve, distributed flexibility is becoming a more critical component of PGE's resource portfolio. Order No. 20-152 acknowledged PGE's action item to seek to acquire all cost-effective and reasonable distributed flexibility. In PGE's 2019 IRP action plan, the estimated amount of cumulative distributed flexibility resources for 2025 was 211 MW summer demand response (DR), 141 MW winter DR, 137 MW dispatchable standby generation, and 4 MW dispatchable customer storage.

The subsections below provide a brief update on recent distributed flexibility activities. Additionally, information about the recently filed Flexible Load Plan is provided in **Section 2.3.1**.

In reply to Staff's Memo in LC 73, PGE agreed to provide information regarding trends in sales by customer class and 2015-2019 behind-the-meter photovoltaic (PV) installments; this was accepted by the Commission.[6,7] PGE discussed customer class demand trends in the October 2020 Roundtable and information is also provided in **Appendix B**. Annual quantities of behind-the-meter solar on the system from 2015-2019 are provided in **Appendix C**.

Flexible Load installation trends

PGE has continued to make progress across several planning and programmatic areas pertinent to developing a portfolio of distributed flexibility. **Figure 1** below shows historical DR resource acquisition levels across PGE's portfolio of activities covering the period 2015 to 2019.[8]

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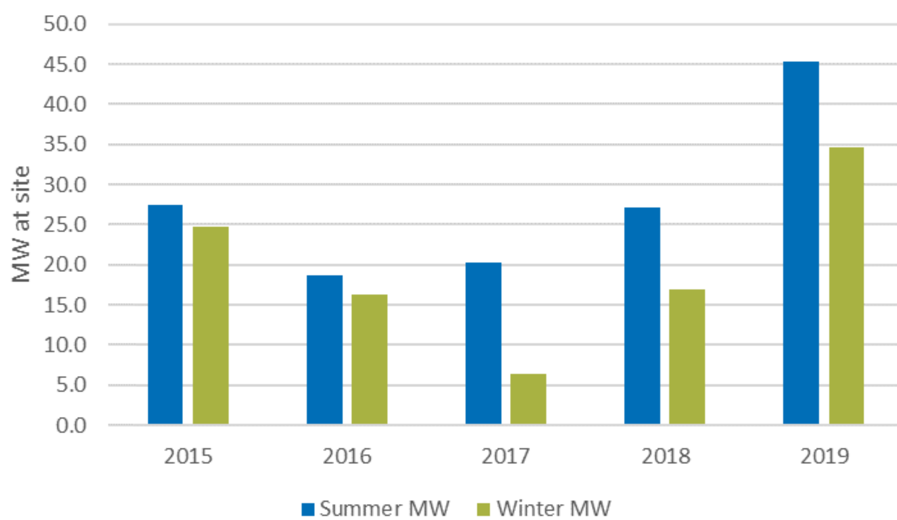
[6] See LC 73, PGE's Response to Staff Memo at 14.

[7] Order No. 20-152 at 22.

[8] Note that the downward trend in 2016 and 2017 are due in part to movement of customers to direct access, and PGE transitioning the Energy Partner pilot due to underperformance by a previous implementation vendor. Energy Partner is a non-residential offering that incentivizes customers to modify energy demand during utility-defined peak periods. To learn more visit: https://portlandgeneral.com/save-money/save-money-business/energy-partner

FIGURE 1. PGE HISTORICAL CUMULATIVE DEMAND RESPONSE ADOPTION BY SEASON



As can be seen from **Figure 1**, PGE has steadily increased the amount of enrolled DR in our portfolio from 2017 to 2019. This increase in DR enrollments and associated MW in the portfolio is the result of concerted efforts to adjust current approved pilots based on implementation experience and third-party evaluation, the addition of new product offerings, and efforts to scale these pilots. In particular, the following updates have played a significant role in growing the DR resource:

- Energy Partner contract changeover and aggressive outreach efforts to diversify the types of commercial and industrial loads enrolled by the program.
- Flex residential pricing pilot received Commission acknowledgment[9] to scale beyond the initial 14,000 pilot enrollment cap and offer an optional (opt-in) peak time rebate (PTR) program to all eligible Schedule 7 customers. Enrollment through year-end 2020 in the Flex PTR offering is greater than 90,000 residential customers.
- Expanded the Connected Savings residential thermostat pilot based on success of early evaluation results, including adding delivery channels and additional qualifying models, to enroll more than 25,000 customers.

Progress has continued throughout 2020, even amid the many challenges to customer-facing programs brought on by the COVID-19 global pandemic. The economic recession and customer disruption stemming from the COVID-19 pandemic led to a reduction in DR installations in 2020 (compared to goals) due to a combination of factors, such as reductions in new sales opportunities as well as eliminations of on-site direct install measures. The pause on direct install

[9] See Docket No. ADV 920, Advice No. 19-03, available at: https://edocs.puc.state.or.us/efdocs/UBH/adv920ubh12524.pdf

from the beginning of the pandemic through mid-October was a main factor reducing winter achievement, given that the direct install channel is an important way to secure electric furnace or heat pump participation in our programs. We developed a Virtual Install assistance offering in late June to make up for this loss. As of December, we have reverted to solely offering Virtual Install assistance given the surge in Coronavirus cases nationwide. In addition, there was a reduction in Energy Partner summer DR nominations for 2020 due to COVID-19 forced closures. PGE is not considering these as permanent reductions to our DR capacity but will continue to monitor economic trends as the impacts persist into 2021 and beyond.

PGE is closely monitoring the progress to the 2019 IRP goals for the year 2025 of 211 MW of summer DR and 141 MW of winter DR, and will continue to adjust based on market changes, program evaluations, and continued engagement with Staff and participants. PGE is exploring the feasibility of the following customer offerings and market strategies to help meet interim targets and continue to grow the Flexible Load portfolio:

- Non-residential customer energy storage,
- Single family water heater,
- High-voltage thermostats for baseboard electric resistance heat customers,
- Supporting regional efforts related to building energy codes and appliance standards, and
- Developing new construction offerings and product bundling strategies.

PGE looks forward to engaging with participants as we continue to learn from our current pilot offerings and develop additional products that help advance our reliability, system flexibility and decarbonization goals and meet our customer's evolving expectations.

Resource-specific updates and new flexible load initiatives

The following section provides further detail and updates by resource and programmatic area concerning activities currently in flight. These combined efforts add significant depth and learnings opportunities to PGE's longstanding experience with DR programs.

Smart Grid Test Bed

The PGE Smart Grid Test Bed (SGTB) was developed in response to OPUC Order No. 17-386[10] from the 2016 IRP and approved under Order No. 19-425[11] in conjunction with the Demand Response Review Committee (DRRC). The SGTB is an innovative effort to understand the pathways to scale distributed flexibility resources, and help move PGE beyond pilot

[10] Available at: https://apps.puc.state.or.us/orders/2017ords/17-386.pdf
[11] Available at: https://apps.puc.state.or.us/orders/2019ords/19-425.pdf

demonstrations of DR. The SGTB officially launched in September 2019, and so far, has met its aggressive goal of 66% residential sector participation across PGE's approved DR pilot offerings.

PGE plans to continue launching field pilots of new and important technologies through the SGTB in 2021, including line voltage thermostats and controls for ductless heat pumps and heat pump water heaters. All three of these technologies are expected to help provide more winter DR resource. In particular, if the line voltage thermostat proves successful, this would be very promising given the high amount of electric resistance heating in multifamily settings in PGE's territory that is currently incompatible with PGE's existing thermostat offerings. PGE has had discussions with Energy Trust of Oregon about a joint pilot for line voltage thermostats and will continue to look for opportunities that can help achieve scale for this, and other, smart grid technologies.

UM 1856 energy storage pilot initiatives – customer-sited installs

In response to HB 2193,[12] PGE proposed a series of battery storage pilots under UM 1856 and received Commission approval under Order No. 18-290 for a residential storage pilot and non-residential microgrid pilot projects.[13] PGE reports the following activity and expected in-service dates for the customer-sited portions of UM 1856 activity:[14]

- **Beaverton Public Safety Center:** In-service as of November 2020, this installation is a combined solar (300 kW), battery energy storage (250 kW), and diesel generator (1,000 kW) microgrid for a new, resilient building for Beaverton's Emergency Management Department and Police Department.
- **Anderson Readiness Center:** With an expected in-service date during late Q4 2021, this installation is a combined solar, battery energy storage (500 kW), and diesel generator microgrid for an Oregon National Guard building.
- **Residential Smart Battery Pilot:** Active as of August 1, 2020, we launched a five-year pilot to incentivize the installation and connection of 525 customer-owned residential energy storage batteries (up to 4 MW/8 MWh in total) that PGE will dispatch as a virtual power plant made up of small units that can be operated individually or combined to serve the grid, adding flexibility.

Electric Vehicle (EV) Smart Charging

EV adoption is expected to accelerate and drive additional demand for electricity as a fuel source. PGE understands that we must take a leadership role in enabling this rapid transformation of the transportation sector. As the fuel providers in an electric transportation ecosystem, the electric

[12] Available at: https://olis.leg.state.or.us/liz/2015R1/Measures/Overview/HB2193
[13] See: https://apps.puc.state.or.us/orders/2018ords/18-290.pdf
[14] More information on these and other related activities is available via PGE's Annual Energy Storage update. See: https://edocs.puc.state.or.us/efdocs/HAD/um1856had151753.pdf

utility's role in ensuring customers have access to electric fuel will continue to grow and be more integral to our customers' lives. Electric utilities must make the right investments to ensure that our communities are positioned to effectively and equitably transition to electric fuel; and do so in a timely manner that creates value for our customers and the electric grid. The IRP plans for this new load by including forecasted EV load incremental to its econometric load forecast.[15] Future EV growth may present new challenges if consumer charging coincides with system peak load. However, by working proactively with our customers PGE will be able to integrate these resources as a grid-connected flexible load. We recently launched our residential smart charging program that aims to enroll up to 5,000 residential customers over three years in order to ensure efficient integration into the grid of these important new customer loads.[16] Participating customers will receive a cash rebate to offset the cost of a networked level 2 home charger that is capable of curtailing charging during event periods (known as direct load control). Customers will also have the opportunity to enroll in a time-of-use rate to incentivize off-peak charging behavior.

2.2. Capacity and Renewable Actions

Order No. 20-152 acknowledged PGE's proposed renewable and capacity procurement action items subject to addition conditions related to request for proposals (RFP) design and updated demonstrations of need. In its 2019 IRP, PGE proposed procuring existing capacity resources through bilateral negotiations as one component of its capacity action. The Commission supported this action to secure existing resources, but also noted the role that new capacity resources may have in reducing long-term capacity costs.[17] In addition, the Commission acknowledged PGE's proposed action items to procure approximately up to approximately 150 MWa of renewable resources that contribute to meeting PGE's capacity needs by the end of 2024[18] and to procure sufficient non-emitting capacity resources to meet PGE's remaining 2025 capacity need. As a condition of its acknowledgment, the Commission called upon PGE to continually re-evaluate its needs in light of the pandemic's uncertain economic environment and to demonstrate through RFP design process that PGE would optimize the procurement of capacity and renewable resources whether through one or multiple solicitations.[19]

In **Section 2.2.2**, PGE provides updates on the expected RFP design and timing. Updated resource need and position assessments are provided in **Section 3**. As detailed in that section, PGE continues to face 2025 capacity needs, although the magnitude of that demand has been reduced through resource actions.

[15] See 2019 IRP, Section 4.1.3.1.
[16] Portland General Electric Company (PGE) Advice No. 20-18, NEW Schedule 8, Residential Electric Vehicle Charging Pilot, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=22516
[17] See Order 20-152 at 25.
[18] See Appendix Section 8.8.1 for more detail.
[19] See Order 20-152 at 26.

2.2.1. Bilateral Negotiations

In addition to the items discussed below, PGE continues to evaluate and monitor our capacity needs and remains engaged with owners of existing regional resources to determine the availability and suitability of capacity offerings to help meet PGE's system needs. PGE looks forward to continuing to provide updates to the Commission regarding its bilateral negotiation efforts.

Douglas PPA

Through bilateral negotiations, PGE and the Public Utility District No. 1 of Douglas County, Washington (Douglas) reached an agreement that allows us to collaborate in optimizing resources to support clean energy for our customers. A cost-competitive power purchase agreement (PPA) was executed in May 2020 to secure capacity from existing resources to partially meet PGE's forecasted capacity deficits from 2021 through 2025. Under the contract between PGE and Douglas (Douglas PPA), PGE will purchase surplus capacity, energy, ancillary services, and environmental attributes associated with the Douglas and Public Utility District No. 1 of Okanogan (Okanogan) resource portfolios.[20] Additionally, PGE will manage load supply and wholesale market services for Douglas and Okanogan.[21]

2.2.2. IE Docket and RFP Process

Following the information made available in this IRP update, PGE will start the process of conducting a competitive solicitation for capacity and renewable resources. PGE has not altered its proposed procurement action plans and will continue with available bilateral procurement opportunities. Any bilateral procurement will be joined by competitive procurement for up to approximately 150 MWa of renewable resources and non-emitting capacity resources to address PGE's 2025 forecasted capacity shortfall.

Since acknowledgment of the 2019 IRP, PGE has considered how to best meet the Commission's direction to optimize capacity and renewable procurement across one or multiple solicitations.[22] Currently, PGE expects to propose a single solicitation for renewable and non-emitting capacity resources that will naturally identify that portfolio of resources best suited to meet PGE's resource needs.

Since the Commission acknowledged the 2019 IRP, PGE has updated the expected timing of the competitive solicitations proposed to meet the 2019 IRP Action Plan items. Concurrently with

[20] The resource portfolios include: the Wells Project, shares of the Rocky Reach Project, a portion of the Nine Canyon Wind Farm, and PPAs from BPA and Avista. Environmental attributes are only received for Douglas' and Okanogan's shares of the Wells and Rocky Reach Projects.
[21] Douglas will continue to operate its Balancing Authority Area (BAA) and the PPA contains safeguards addressing possible situations where the Douglas and/or Okanogan portfolios are insufficient to address their own needs.
[22] See Order 20-152 at 26.

the review of the 2019 IRP Update, PGE will collaborate with OPUC Staff to recommend an Independent Evaluator (IE) for Commission consideration. Upon selection of an IE, PGE intends to share its proposed RFP design for participant review, Commission consideration and approval as a continuation of the IE selection docket.[23]

PGE will seek Commission RFP approval and launch its solicitation process in 2021. By adopting a measured pace that meets the Commission's procedural requirements,[24] PGE will monitor and respond to any important changes relative to resource need or state and federal policy. PGE looks forward to working with Staff, participants, and the Commission to advance these important resource procurement processes.

2.3. Enabling Analyses, Studies, and Additional Requirements

This section provides status updates on analyses, studies, and additional requirements from Order No. 20-152. As described below, PGE has made substantial progress in these activities and we will continue to share the results of our efforts with parties in the IRP Roundtable process.

2.3.1. Flexible Load Plan

Order No. 20-152 highlighted the importance of PGE's Flexible Load Plan (FLP) in advancing participants' understanding of the company's approach to evaluating demand-side resources as a comparable resource to supply-side capacity.[25]

PGE submitted a draft of the FLP to Staff for review and comment on June 19, 2020 and a second draft on October 1, 2020. The final FLP was filed on December 24, 2020, docketed as UM 2141.[26]

The FLP covers aspects of program planning and long-term resource planning. Part of the FLP's intent is to highlight PGE's approach to evaluating distributed flexibility in a holistic manner within the IRP portfolio analysis. To advance toward this long-term vision, PGE will need to develop more refined tools for calculating potential based on specific resource attributes of flexible loads, as well as integrate new approaches to quantifying locational value of distributed energy resource (DER) and flexible load adoption. PGE's new distributed resource planning (DRP) team will lead this integration, working closely with the IRP team and other departments as necessary. PGE expects the FLP to be an evolving document, especially as it pertains to participants' understanding of how DR and Flex Loads are treated within the IRP context. We anticipate that FLP workshops and Commission review will also inform this evolution, and we look forward to continuing the discussion with participants during the next IRP cycle.

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[23] PGE will follow the procedure identified in the recently updated Competitive Bidding Rules. See OAR 860-089-0250.

[24] *Id*.

[25] See Order No. 20-152 at 21.

[26] See: https://edocs.puc.state.or.us/efdocs/HAS/um2141has132229.pdf

The FLP identifies multiple areas for closer integration and coordination across existing pilot efforts. Continued progress along these lines will provide increased insight and shared understanding for Staff and participants as to how PGE aims to approach distributed flexibility as a resource in the IRP context. Specifically, PGE provides the following updates related to planned efforts to track distributed flexibility goals from the 2019 IRP action plan:

- As discussed in the FLP, the DRP team is developing a set of processes to track DER and flexible load portfolio accomplishments against the goals set out in the 2019 IRP action plan. PGE will provide updates to Staff through UM 2005 as appropriate,[27] and elsewhere as requested by Staff and participants.

- PGE understands the importance of continuing to provide transparent evaluation and reporting mechanisms as we engage with Staff and participants about the "pilot to program" continuum. PGE expects that as IRP modeling and characterization of flexible loads continue to evolve, this process will take on heightened importance to ensure the best selection of resources in preferred portfolios and action plans. To facilitate participants' understanding of PGE's processes around flexible load planning, the DRP team plans to coordinate the implementation of the following actions (others may be added in conversation with Staff and participants):

    - Develop an efficient and transparent product/program third-party evaluation review process that informs future planning efforts

    - Establish consistent and transparent methods for tracking flexible load product performance for various reporting purposes. PGE aims to clearly define processes and expectations around the following areas:

        - Pilot and product planning (i.e., measure development)

        - Program goal setting, budgeting, and performance tracking (including cost tracking and cost recovery)

        - Developing IRP inputs for long-term resource characterization (i.e., potential assessment)

    - Improving resource characterization in IRP modeling by more sophisticated modeling of resource parameters. These efforts will improve analysis of the benefits and resource attributes of DERs and flexible loads.

[27] In their final approved "Distribution System Planning (DSP) Guidelines", Staff presents a process for reporting on both baseline DER adoption and forecasted DER adoption at the substation level. As PGE's DRP Team develops the analysis and reporting tools necessary to meet this requirement, we will coordinate with Staff and participants to identify areas of mutual interest. See UM 2005 "Investigation into Distribution System Planning", accessible here: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21850

PGE looks forward to continuing the conversation around PGE's FLP in upcoming workshops.[28] We anticipate these workshops leading to Commission action regarding PGE's request for acknowledgment of the proposal to move to a more holistic, portfolio level planning and budgeting approach to flexible load development.

2.3.2. Distributed Energy Resources Study

In addition to the Flexible Load Plan, PGE hired Cadeo, with subcontracts to Brattle and Lighthouse Energy Consulting, to conduct a DER and Flexible Load study that will inform the 2022 IRP and PGE's initial filing of its distribution system planning (DSP) under Docket No. UM 2005. As part of this effort, PGE will develop a system-level DER forecast for IRP purposes, and a disaggregated bottom-up DER potential assessment that views results at the granular feeder level. The system-level study for the IRP will provide more robust characterization of resource attributes, thus allowing for more comprehensive analysis of potential use cases. In addition, the granular feeder-level results will be calibrated to the system-level forecast but will add important visibility regarding differences in customer demographics and building types across PGE's service area. Both approaches are important to advancing the integration of DERs into PGE's grid modernization planning efforts, as they will inform locational valuation of grid services.

PGE will communicate about the study goals, methods, and results during both the public process for the next IRP, and the UM 2005 process for distribution system planning. Preliminary information was shared with participants in the December 2020 IRP Roundtable.

2.3.3. Colstrip Update

In accordance with Commission Order No. 20-152, PGE has completed the Colstrip Enabling Study.[29] The 2020 Colstrip Enabling Study included additional analysis beyond that included in the 2019 IRP, providing an expansion of sensitivity scenarios in which Colstrip exits PGE's portfolio before the end of 2034 and investigating estimated near-term customer price impacts.[30] The study considered six alternative scenarios of the potential Colstrip removal year from the PGE portfolio and the depreciation end year. The analysis was presented as informational as the ability to pursue each scenario is dependent upon a combination of regulatory, contractual, commercial, and/or legislative actions.

Consistent with sensitivity analysis in the 2019 IRP, updated long-term portfolio analysis results in the Colstrip Enabling Study found long-term economic benefits and GHG emission reductions when Colstrip was removed from the portfolio prior to 2034 under Reference Case conditions.

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[28] See: https://edocs.puc.state.or.us/efdocs/HNA/um2141hna16110.pdf

[29] Order No. 20-152 at 9.

[30] The 2020 Colstrip Enabling Study is available at: https://portlandgeneral.com/about/integrated-resource-planning , in the section for 2019 IRP Studies.

The expanded set of scenarios indicated that portfolio cost and risk decrease with increased acceleration of the removal date. Early removal of Colstrip from PGE's portfolio would have a corresponding shift in timing of the increased capacity need associated with its removal from the portfolio.

The Colstrip Enabling Study also included revenue requirement analysis used to estimate the near-term customer impacts of an early removal of Colstrip from PGE's portfolio by accelerating the plant's capital recovery. Any acceleration of the capital recovery for Colstrip would be additive to customer price increases already expected due to updated decommissioning and remediation estimates. These increases can be partially mitigated by extending the recovery period for environmental and decommissioning costs to better align with actual expenditures.

The study concluded that a two-part regulatory solution is required to enable the flexibility for the potential early removal of Colstrip from PGE's portfolio while minimizing near-term customer price increase. These proposed steps are the acceleration of the capital recovery of Colstrip to as early as 2025 and an extension of the timeline for recovery of environmental and decommissioning expenses through the end of 2052.

Since the publication of the Colstrip Enabling Study, efforts to consider options related to Colstrip have continued. These include an updated depreciation study filed in early 2021, as well as continued examination of the impact of accelerated depreciation on customer price increases. To this end, the first step of the regulatory solution proposed has been amended to adjust acceleration of the capital recovery of Colstrip to the end of 2027. The recommendation for the second step above remains as indicated. PGE remains committed to fulfilling remediation and restoration obligations in compliance with Montana state law and to provide for an orderly transition of the plant and community.

As the Colstrip Enabling Study noted, while flexibility to act is important, it does not guarantee an exit from the plant. The Colstrip Enabling Study showed that removing Colstrip from our portfolio prior to the end of 2034 has economic benefits for our customers. However, PGE recognizes that continued collaboration with our co-owners is necessary for a permanent solution in line with our climate goals while ensuring a supportive transition for the Colstrip community. Beyond long-term economic and near-term customer price impacts, there continue to be a range of policy, contractual and operating uncertainties surrounding Colstrip that complicate and drive the importance of continuously evaluating the plant's future within PGE's portfolio.[31]

[31] Please refer the 'Discussion' section of the 2020 Colstrip Enabling Study for additional discussion, available at: https://portlandgeneral.com/about/integrated-resource-planning

2.3.4. **Solar Integration Analysis**

In the 2019 IRP, PGE agreed to further investigate the drivers of PGE's findings regarding solar integration costs. In IRP Roundtable 20-2 on April 14, 2020, PGE reviewed proposed categories of potential investigation for this analysis. Those included but are not limited to sub-hourly resource variability, generation levels, resource forecast error, and reserves associated with resources. The results of this analysis will be discussed in the public process and included in the next IRP.

2.3.5. **Climate Adaptation Study**

In the 2019 IRP, PGE agreed to provide an enabling analysis on climate adaptation in the next IRP. Currently the company is evaluating the most informative methods to examine how a changing climate may affect future customer loads and the characteristics of generating resources, as well as how to align with other regional utilities' and institutions' efforts. This work was presented at the May 20, 2020 public roundtable meeting, and the results of climate analysis will be included in the next IRP.

2.3.6. **Transmission Analysis**

In Docket No. LC 73, PGE submitted its Interim Transmission Solution (ITS),[32] which described a provisional program which modified transmission requirements to the upcoming RFP.[33] In Order No. 20-152, the Commission asked PGE to "…expand its transmission modeling so that it includes known transmission availability, constraints, options, and costs."[34] This work is currently underway; PGE's framework for transmission analysis was presented to IRP participants in April 2020, and the full analysis will be included in the next IRP. Further, PGE is actively monitoring BPA's current rate case (BP-22), Terms and Conditions case (TC-22), and EIM implementation process. The changes to BPA transmission cost and availability from these processes will be incorporated into the next IRP.

[32] Available at: https://edocs.puc.state.or.us/efdocs/HAQ/lc73haq1558.pdf

[33] Traditionally, RFP bidders were required to demonstrate full nameplate capacity output of Long-Term Firm transmission service for the entirety of the potential contract. The ITS allowed for two main modifications for variable renewable resource bidders in the RFP: allowing Conditional Firm transmission products (bridge or reassessment, with a number of hours option), and requiring transmission service for only 80% of the nameplate capacity of the facility.

[34] See Order No. 20-152 at 17.

2.3.7. Voluntary Renewable Programs

As described in the 2019 IRP, customers have increasing options for voluntary participation in elective renewable programs, including both PGE's Green Energy Affinity Rider (GEAR)[35] and the statewide Community Solar program. As these programs develop, it is important to consider their impact to long-term resource planning. In Order No. 20-152, the Commission stated:

> While PGE's sensitivities showed only a modest decrease to its energy and capacity needs from its green energy programs, we find there is some risk of PGE over-procuring resources if it fails to consider these programs. PGE has committed to update its needs assessment in a RFP docket with a consideration of the capacity and energy impacts of its green tariff. We also direct PGE to incorporate examination of customer program growth assumptions, including utility-offered programs and direct access, in its next IRP.[36]

The first tranche of PGE's GEAR received acknowledgment after analysis for the 2019 IRP was already underway and the first enrollment window followed in May 2019, with resource contract execution in November 2019. Similarly, Oregon's Community Solar program was under development at the time of the analysis. While neither program was included in the base analysis for the 2019 IRP, PGE recognized their potential to impact resource needs. The 2019 IRP included sensitivities for these programs to examine their potential impact on capacity need, energy position, and RPS position. Further, in portfolio evaluation, PGE also included a screen to remove any portfolios that added more than 250 MWa prior to 2026 as well as limited the addition in the preferred portfolio to no more than 150 MWa prior to 2025.

At the time of the preparation of analysis for the November 2019 Needs Assessment Update, the first tranche of GEAR was fully subscribed and the resource contracting process was nearing completion. The base analysis was updated to include the 162 MW GEAR resource and updated sensitivities were provided to examine the potential impact of the remaining 138 MW of the approved GEAR as well as Community Solar.

Substantial progress toward implementation of the Community Solar program was complete by the time analysis began for the 2019 IRP Update. The Community Solar program was included in the base analysis as described in **Section 3.3.1**. The IRP Update examines the potential impact of the additional 138 MW of GEAR resources through a sensitivity discussed in **Section 3.7.1**.

PGE has committed to providing sensitivity analysis of a proposed expansion of the GEAR program beyond the original 300 MW in the next IRP and to provide updated sensitivity analysis with a tariff filing. In addition, PGE looks forward to working with Staff and participants to explore

[35] Green Energy Affinity Rider (GEAR) is a formal regulatory term also referred to as "green tariff" and "Green Future Impact" to customers.
[36] Order No. 20-152 at 8.

additional analysis aimed at evaluating the long-term impacts of the potential growth of Voluntary Renewable Programs in the public Roundtable process for the next IRP.

2.3.8. Regional Capacity (Market Capacity)

As discussed in Section 2.4.2.1 of the 2019 IRP, PGE's capacity assessment includes varying quantities of capacity assumed available from existing regional resources. The winter and summer on-peak values were based on a regional capacity model developed by Energy and Environmental Economics (E3). In Order No. 20-152, the Commission requested an update to the E3 model for the IRP Update and that PGE "…consult with Staff about what data (in addition to coal retirements) can be updated . . ."[37]

For the IRP Update, the regional capacity study was updated as described in **Section 3.3.3** to capture a more recent snapshot of regional resources and load. In addition, PGE discussed the model data with Staff and a sensitivity is provided in **Section 3.7.3** in response to Staff's request.

PGE looks forward to a broader discussion about the treatment of regional capacity in the public process for the next IRP. PGE also notes the overlap of these considerations with ongoing work in the development of the Northwest Power Pool (NWPP) regional resource adequacy program as well as the investigation into resource adequacy in the state in Docket No. UM 2143.

2.4. New Information Since Acknowledgment

2.4.1. Executive Order No. 20-04

On March 10, 2020, Governor Kate Brown issued Executive Order No. 20-04 (EO), directing state agencies to take actions to reduce and regulate greenhouse gas (GHG) emissions. Among other directives, the EO directed the OPUC to "determine whether utility portfolios and customer programs reduce risks and costs by making rapid progress towards reducing GHG emissions."[38] In response, the OPUC proposed that it would, among other actions, consider options to incorporate the social cost of carbon into utility IRPs and avoided cost proceedings, and update the IRP guidelines to more explicitly consider the costs and risks of meeting the state's GHG emission reduction targets under the new timelines set forth in EO 20-04.[39]

The OPUC has taken comments from utilities and participants,[40] submitted an implementation report to the Governor in May,[41] and prepared a work plan for its implementation of the

[37] Order No. 20-152 at 12.
[38] Available at: https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf
[39] See OPUC EO 20-04 Work Plans, available at: https://www.oregon.gov/puc/utilities/Pages/ExecutiveOrder20-04.aspx
[40] *Id*., See Stakeholder Comments.
[41] *Id.,* See PUC Report – Response to EO 20-04f.

executive order.[42] PGE will be working with Staff and participants on EO 20-04 implementation for the next IRP. Initial options for carbon price modeling were discussed in the August IRP Roundtable.

2.4.2. Federal Tax Credit Updates

Since the Commission order acknowledging the 2019 IRP, there have been two changes to the federal tax credits available to new renewable resources. The first came in response to the COVID-19 pandemic. In May 2020 the IRS provided additional guidance for Safe Harbor provisions of the PTC, issuing Notice 2020-41 which clarified that projects that began construction in 2016 and 2017 have one additional year to be placed in service and qualify for tax credits under the Safe Harbor provisions.[43] The second tax credit change came on December 27, 2020. This change provided an additional year of eligibility for projects qualifying for the 60% PTC level and provided an additional two years for the elevated levels of the ITC. These updates are reflected in this IRP's portfolio analysis, presented below in **Section 6**, and are further discussed in **Appendix G**.

3. Need and Position Assessments

The IRP Update captures the load and resource updates described in **Section 3.1** and **Section 3.3**. These are reflected in the refreshed capacity need, energy position, and RPS position assessments, and sensitivities provided in **Sections 3.4** to **3.7**.

3.1. Top-down Econometric Load Forecast

For the IRP Update, the top-down econometric load forecast was updated to the June 2020 forecast. The top-down load forecast was updated to integrate the most up-to-date input data and historical deliveries information available at the time of preparation.

As discussed in the following sections and at the October 2020 Roundtable, the updated forecast captures adjustments to reflect the impact of COVID-19 on customer demand and more recent long-term growth rates. Additionally, in **Section 3.1.3**, information is provided about an assessment of alternative economic drivers for the long-term industrial model.

Additional background information about the top-down load forecast is provided in the 2019 IRP in Section 4.1.1 and Appendix D.

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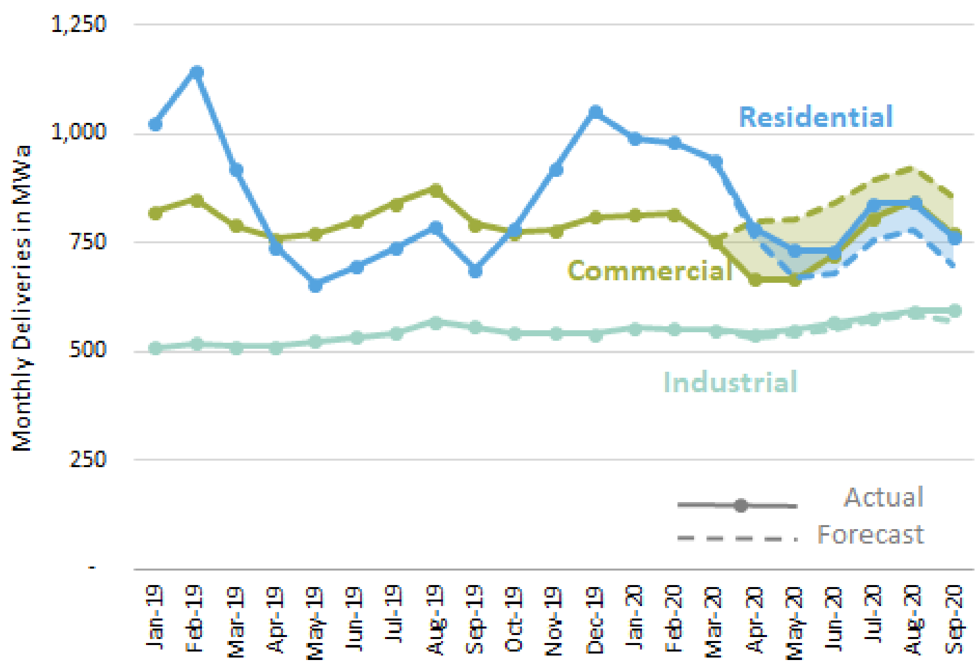
[42] *Id.,* See PUC Work Plans – FINAL.

[43] Available at: https://www.irs.gov/pub/irs-drop/n-20-41.pdf

3.1.1. Near-term Load Forecast and COVID-19

Response to the COVID-19 pandemic has significantly changed the way PGE's customers consume electricity, with usage patterns shifting from the workplace (particularly commercial real estate uses) to the home. **Figure 2** characterizes this shift from commercial to residential usage with approximate impacts on PGE's retail energy deliveries by revenue class. While several industrial customers have shifted some operations, growth in this class continues, fueled by high tech manufacturing.

FIGURE 2. IMPACT OF COVID-19 ON 2020 ENERGY DELIVERIES



When considered in aggregate, the impact of these changes on PGE's total energy deliveries and peak demand in 2020 has been relatively modest. Year-to-date through September, energy deliveries have grown 1.6% as compared to 2019 on a weather adjusted basis and PGE's summer peak demand was very similar to the prior year, up 0.2%.

The top-down load forecast includes manual adjustments made in the near-term model to reflect recent experience with changes in customer behavior related to COVID-19 by segment. However, the high level of uncertainty that exists with respect to the path of the virus and ensuing economic conditions is unprecedented. Understanding of long-term impacts to the structure of the regional economy, sustained changes in workplace and home usage patterns (increased work from home), and associated impacts on PGE's aggregate energy deliveries and peak demand will continue to evolve over coming months and years.

3.1.2. **Long-term Growth Rates**

PGE's long-term growth rates were also updated as a part of its June forecast cycle. These changes reflect inclusion of historical data through February of 2020, and the May 2020 macro-economic forecast. The changes in long-term growth rates are reflected in the table below:

TABLE 1. COMPARISON OF TOP-DOWN ENERGY (MWA) GROWTH RATES

Customer Class	2019 IRP	2019 IRP Update
Residential	0.1%	0.2%
Commercial	0.5%	0.9%
Industrial	1.9%	1.9%

The resulting forecast reflects slightly increased long-term growth as compared to the 2019 IRP. This is driven primarily by an increase in the commercial growth rate associated with stronger employment growth, following the sharp decline in 2020. While there has been downward revision to the near-term load forecast to reflect the impact of COVID-19 on PGE's commercial energy deliveries, increased residential usage (in the near term) and continued growth in high tech manufacturing, which extends into the long term, has more than offset this impact as compared to the prior vintage of the top-down load forecast (the September 2018 load forecast was used in the 2019 IRP).

Figure 3 compares the top-down econometric load forecast used in the 2019 IRP Update to the 2019 IRP and November 2019 Needs Assessment Update on an average energy basis (in MWa). **Table 2** shows a comparison of seasonal peak demand (in MW).

FIGURE 3. TOP-DOWN LOAD FORECAST COMPARISON, AVERAGE ENERGY IN MWA

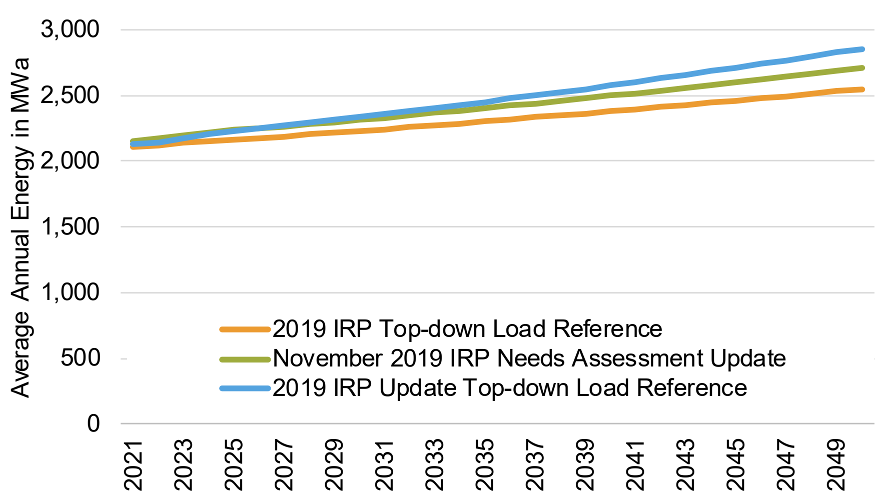


TABLE 2. LOAD FORECAST COMPARISON, PEAK DEMAND IN MW[44]

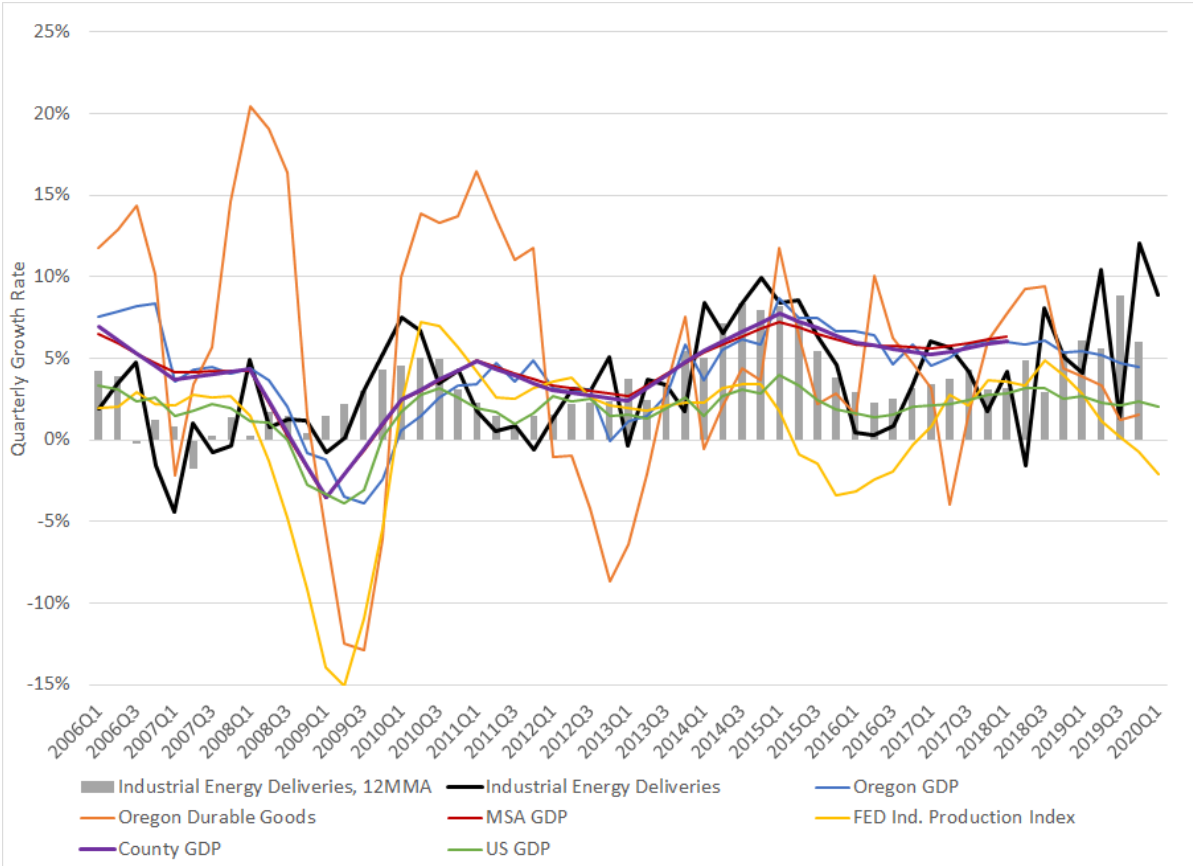
	Reference Case 2019 IRP			Reference Case 2019 IRP Update		
	2021	**2050**	**AAGR**	**2021**	**2050**	**AAGR**
Summer	3,439	4,184	0.7%	3,440	4,308	0.8%
Winter	3,362	3,914	0.5%	3,440	3,966	0.5%
Annual	3,439	4,184	0.7%	3,440	4,308	0.8%

3.1.3. **Industrial Drivers**

In response to comments by CUB in OPUC Docket No. LC 73, PGE assessed alternative economic drivers in its long-term industrial model. In the 2019 IRP, PGE presented a methodology that forecasted long-term industrial demand by using historical usage and national Gross Domestic Product (GDP) levels. In their opening comments, [45] CUB suggested PGE use a more regionally specific driver of industrial levels. Following CUB's recommendations, PGE evaluated several potential alternative data series for usefulness as an input to its industrial model, including Oregon GDP, Portland GDP, a weighted GDP of service territory counties, the Oregon Durable Goods Manufacturing component of state GDP, and the Federal Reserve's US Industrial Production Index.[46] The quarterly growth rates of these data series are displayed below in **Figure 4**:

[44] Consistent with Table 4-7 from the 2019 IRP, at 103.
[45] Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc73hac132227.pdf at 8-11.
[46] These series are available from the US Bureau of Economic Analysis (BEA) at: https://www.bea.gov/ with the exception of the Industrial Production Index which is available from the Federal Reserve at: https://fred.stlouisfed.org/

FIGURE 4. INDUSTRIAL DRIVER QUARTERLY GROWTH RATES[47]



PGE tested the performance of the industrial model with these data series used as independent explanatory variables, and US GDP continues to be the preferred driver. Both the State and regional series exhibited significantly more volatility than the national indices, and US GDP outperformed the industrial production index. The industrial production index likely captures a mix of firms quite different from the industrial customers in PGE's service territory, which tend to be more technologically focused. Accordingly, a more general nation-wide GDP series explains more of the variation associated with PGE's industrial customers. PGE will continue to evaluate model fit and predictive ability going forward, which will include the further examination of alternative independent variables.

[47] The Industrial Energy Deliveries 12-month moving average (12MMA) is shown in the columns.

3.2. Distributed Energy Resources

DER forecasts were discussed in Section 4.1.3 and Section 5.1 of the 2019 IRP. Their forecasts remain the same in this IRP Update. PGE is working with Cadeo on an updated DER Study that will inform the 2022 IRP (see **Section 2.3.2**).

3.3. Resource Updates

The following sub-sections describe the key resource updates since the November 2019 Needs Assessment.

3.3.1. **Voluntary Renewable Programs Updates**

The Oregon Community Solar program allows customers to subscribe to a portion of a local community solar project. While PGE will not receive renewable energy credits (RECs) from Community Solar resources, the program will reduce the RPS obligation because the associated load is not included in the obligation calculation. In the 2019 IRP, the potential impact of the Community Solar Program on capacity, energy, and RPS needs was examined through sensitivities to the need and position assessments.[48]

As mentioned in **Section 2.3.7**, substantial progress toward implementation of the Community Solar program was completed by the time analysis began for this IRP Update. In the IRP Update, the base resource stack was updated to include the estimated resources of the Community Solar program. Approximately 93 MW of Community Solar resources were included in the modeling of the Baseline Portfolio,[49] with half of the Community Solar resources beginning in January 2022 and the second half beginning in January 2023.[50]

The GEAR resources impact capacity need and energy position, but as discussed in Section 4.7.2 of the 2019 IRP, they do not impact PGE's RPS obligation. The modeling of the Baseline Portfolio in the IRP Update includes the 162 MW of GEAR initial offering resource that was included in the November 2019 Needs Assessment. The potential impact of the remaining 138 MW of the approved GEAR program on the need and position assessment is examined through a sensitivity discussed in **Section 3.7.1**.

[48] See 2019 IRP, at Section 4.7.2, and November 2019 Needs Assessment Update at Section 5.1.
[49] The Baseline Portfolio includes existing and contracted resources as well as DERs. It does not include the supply-side resource options considered in portfolio construction.
[50] PURPA Qualifying Facility projects were also updated to reflect anticipated terminations related to the Community Solar Settlement Agreement. See Section 3.3.2.

3.3.2. Contract Updates

PGE refreshed the need and position assessments to include a more recent snapshot of executed contracts, most notably, the recently executed Douglas PPA, which provides additional non-emitting capacity and energy through 2025, as discussed in **Section 2.2.1**.

PURPA Qualifying Facility (QF) contracts were updated to reflect a June 15, 2020 snapshot of contract executions, terminations, and schedule updates. Additionally, anticipated terminations related to the Community Solar Settlement Agreement were incorporated.[51]

As discussed previously in LC 73, there are uncertainties in the quantity of executed QFs that will reach commercial operations, the date projects will enter commercial operations, and the quantity of additional contracts that may be executed in the near-term.[52] **Section 3.7.2** provides sensitivities of the potential impacts to the need and position assessments from uncertainties of QF quantities.

3.3.3. Regional Capacity Update

The 2019 IRP included a regional capacity study prepared by E3 that modeled the winter and summer regional capacity supplies and demand for 2020-2035 calibrated to the Northwest Power and Conservation Council's (the Council) 2023 Regional Adequacy Assessment with inputs from the Council's 7th Power Plan.[53]

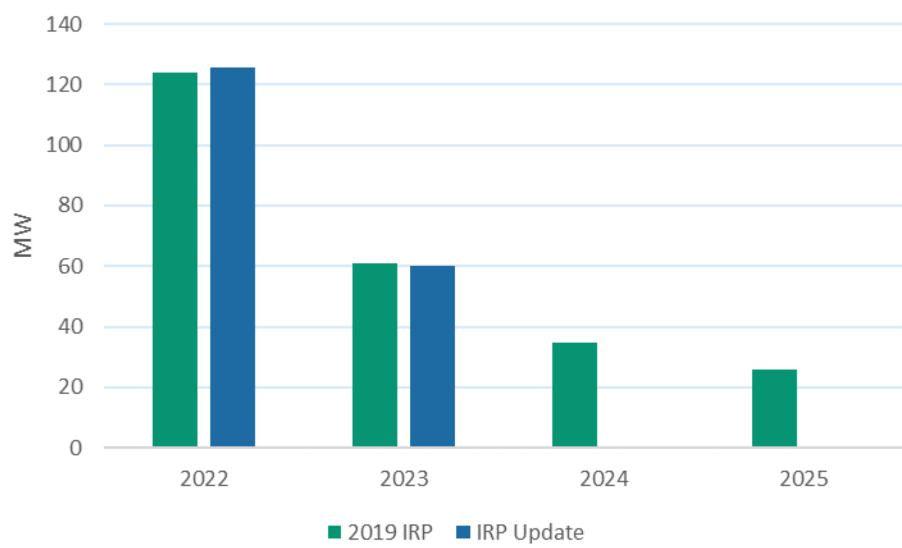
For the IRP Update, PGE updated the resources in the regional capacity model based on the Council's generating resources project database from June 2020, capturing more recent views of both retirements and additions (a net decrease relative to the E3 model). Forecasted loads for 2024 were updated based on the Council's 2024 Resource Adequacy Assessment, which increased compared to the forecast in the E3 model.[54] Additionally, the load growth rate after 2024 was updated to the Council's long-term growth rate from the 7th Plan.[55]

The E3 model provided the recommended assumptions for estimated winter and summer on-peak market capacity for long-term planning that were incorporated into PGE's capacity assessment model. The values represent a theoretical amount of capacity that for planning purposes, we assume can be secured on an hour-ahead basis in constrained conditions without any prior contractual rights. **Figure 5** compares the 2019 IRP and IRP Update assumptions for

[51] The settlement agreement was filed by PGE in Docket No. ADV 1112 on May 15, 2020.
[52] See LC 73 PGE's Reply Comments at 61-64.
[53] See 2019 IRP, at Section 2.4.2.1.
[54] For simplicity, the load forecasts were not updated for years prior to 2024. PGE notes that the Council has released additional information since the versions captured in this update. PGE looks forward to updating the Regional Capacity modeling in the 2022 IRP.
[55] Previously, the regional capacity model used a load growth rate for 2024-2035 was based on the compound growth rate from 2020-2023.

summer on-peak market capacity for the Reference Case, applying the same load ratio apportionment methodology used by E3 for the 2019 IRP. For both the 2019 IRP and the IRP Update, the values for winter are 0 MW for 2022 and later, as the models project a regional capacity deficit.

FIGURE 5. COMPARISON OF SUMMER ON-PEAK MARKET CAPACITY ASSUMPTIONS FOR PGE'S LONG-TERM PLANNING



PGE discussed the Regional Capacity update with Staff in June 2020. Staff expressed an interest in seeing an additional view of market capacity that replaced E3's load ratio apportionment methodology with an allocation of 100% of any estimated regional surplus to PGE. This is provided as a sensitivity in **Section 3.7.3**.

3.4. Capacity Assessment

The IRP Update capacity assessment provides updated capacity need based on the load and resource updates discussed in **Section 3.1** and **Section 3.3**. The analysis used the same adequacy metric as the 2019 IRP and was performed with PGE's new capacity assessment model, Sequoia, which is described in **Section 3.4.1**.

For PGE's long-term planning:

- **Capacity adequacy** means that a system has sufficient resources to meet a reliability standard (e.g., a loss of load probability of one event in ten years).
- **Capacity need** is the amount of additional capacity needed to achieve the reliability standard.

- **Capacity contribution** is the reduction to capacity need from adding a resource. It is dependent both on the resource characteristics and the characteristics of the system.

Background information on capacity adequacy can be found in Section 4.3 of the 2019 IRP. Updated capacity contribution values are provided in **Section 5.3**.

3.4.1. **Sequoia**

In the 2016 IRP, PGE worked to improve its capacity assessment by adopting a rigorous loss-of-load probability model (RECAP) and built on this in the 2019 IRP by continued improvements to the modeling of resources (e.g., the treatment of DERs and storage resources in the 2019 IRP). During that process, PGE saw the need to further advance its modeling capabilities, particularly to better address energy-limited resources (e.g., hydro with storage, battery storage, flexible load, duration limited contracts) and to incorporate process efficiency improvements. With these goals, PGE developed a new proprietary adequacy model, Sequoia.

Sequoia is also a loss-of-load probability model that assesses both capacity need and capacity contribution of potential incremental resources. The model uses a Monte Carlo module to construct thousands of plausible weeks of load and resource conditions. It then evaluates these weeks independently in a dispatch module that optimizes the generation from dispatchable resources across all hours of the week to minimize a reliability objective (e.g., minimize unserved energy). **Table 3** provides a comparison of some of the characteristics of Sequoia to those of RECAP.

TABLE 3. COMPARISON OF SOME RECAP AND SEQUOIA CHARACTERISITCS

	RECAP	Sequoia
Dispatch	Resources cannot be dispatched within the model. Availability in each hour is fixed based on hour-independent stochastic variables for all resources.	Dispatchable resource generation can be optimized across all hours of a given week, allowing for better resource characterization.
Portfolio Interaction	Availability of each resource has no bearing on the availability of others within the model.	Resource dispatch is optimized across the full portfolio to better capture interactive effects between resources.
Process	Exogenous estimates from heuristics and outboard calculations are used to estimate the impacts of energy limitations and availability of other resources and then these estimates become fixed profiles within the model. This is an inefficient process and the outboard information cannot be refreshed for each update to the model.	Energy limitations and interactions between resources are solved for by the model endogenously. This is more accurate, more efficient, and is always based on the latest information included in the model.

The RECAP model reported capacity need based on MW of conventional units (100 MW, five percent forced outage rate) for the 2016 and 2019 IRPs. Sequoia expresses capacity need in terms of theoretical perfect capacity (always available). By itself, switching from conventional units to perfect capacity reduces total identified capacity needs, in this case by approximately seven percent. All else held constant, this change in convention would also have a corresponding impact (reduction) to all capacity contributions for incremental resource so there is no change in the amount of infrastructure required to meet a given reliability target. This change in convention would also have a corresponding impact (increase) to the net cost of capacity so that total capacity value for each incremental resource would remain unchanged.

As part of the development of Sequoia, PGE conducted a baselining exercise to compare the capacity need results from the November 2019 Needs Assessment Update (prepared with RECAP) to the results from Sequoia given the same vintage of load and resource information. Details of this exercise are provided in **Appendix K**. The exercise showed a reduction to capacity need from 697 MW to 601 MW, with approximately half of the decrease attributed to the change to reporting from reporting units (conventional to prefect capacity) and the other half attributed to the more sophisticated modeling in Sequoia.

Through the baselining exercise, we found that at this point, while Sequoia provides for a more sophisticated modeling of our system, the approximations implemented for energy-limited resources in RECAP appeared to have been reasonable for the 2019 IRP. Going forward, as we work to decarbonize our system and introduce more dispatchable energy-limited resources, the challenges of maintaining appropriate approximation methodologies for RECAP will increase.

We find this to be an appropriate time to adopt a model that allows for optimized dispatch of the resource portfolio across a given week.

Following the baselining exercise, Sequoia was updated for the load and resource updates described in **Section 3.1** and **Section 3.3**. Minor refinements were also added to improve resource characterization, such as some of the hybrid resource constraints described in **Appendix K**.

Additional background about Sequoia is provided in **Appendix K**. Information about Sequoia was also shared with participants in Roundtables 20-1, 20-3, and 20-5.[56] PGE also shared information with UM 2011 participants during an OPUC workshop on November 12, 2020.

3.4.2. **Capacity Need**

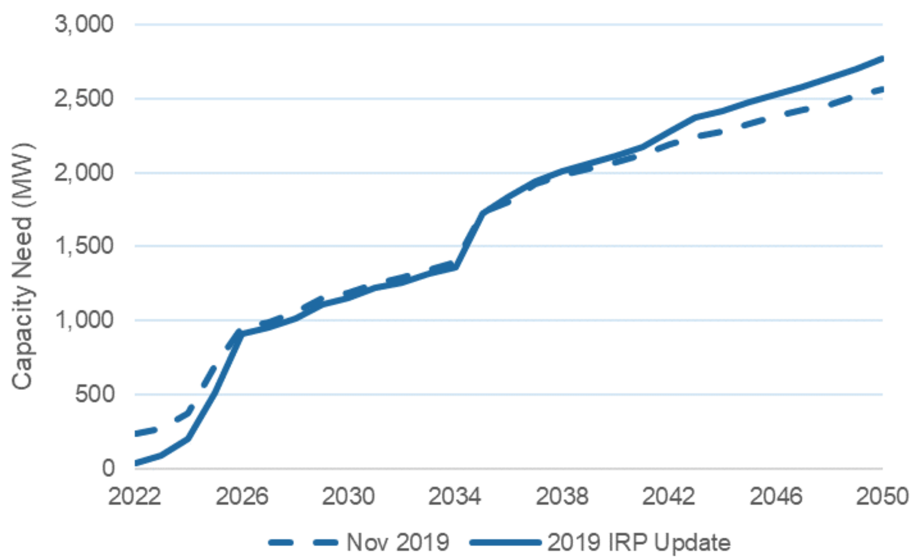
As discussed in **Section 3.4.1**, the change from RECAP to Sequoia resulted in a reduction to the MW of capacity need because of both the more sophisticated modeling of the system and the change to express capacity need in terms of perfect capacity instead of conventional units with a five percent forced outage rate.[57]

The net impact of the load and resource updates resulted in a further decline to capacity need through 2025 due primarily to the addition of the Douglas PPA. The updated Reference capacity need in 2025 is 511 MW, increasing to 909 MW in 2026. In the outer years, capacity need increased due primarily to the load forecast update (see **Section 3.1.2**). **Figure 6** compares the capacity need in the Reference Case between the November 2019 Needs Assessment and the IRP Update.

[56] Roundtable slides are available at: https://portlandgeneral.com/about/integrated-resource-planning/irp-public-meetings/

[57] Unless noted otherwise, all capacity values reported from the 2019 IRP and the November 2019 Needs Assessment Update are expressed in terms of MW of conventional units (100 MW, five percent forced outage rate) while all capacity values reported for the IRP Update are in terms of perfect capacity. It can be roughly approximated that 1 MW of perfect capacity is equal to 1.07 MW of conventional units.

FIGURE 6. COMPARISON OF REFERENCE CASE CAPACITY NEED



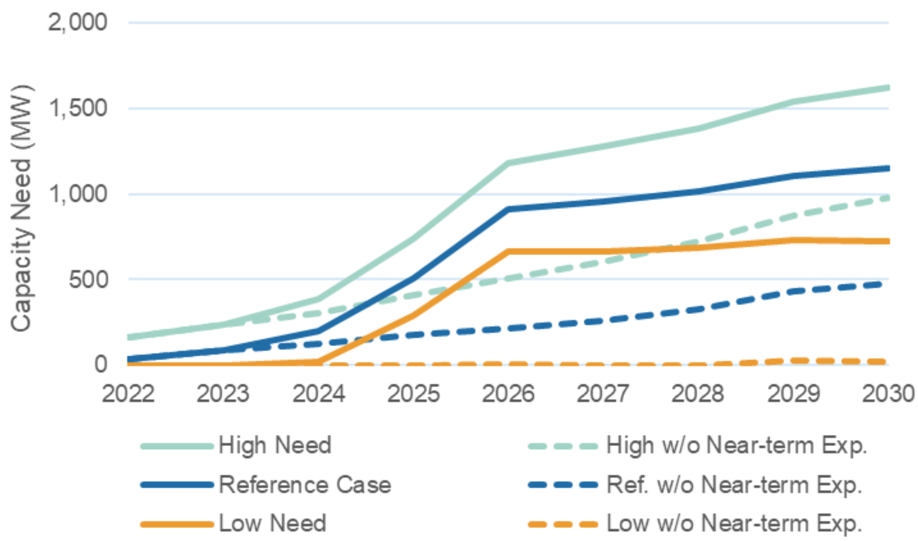
The capacity need for the Low and High Need Futures were also updated for the top-down load forecast and resource updates (shown in the solid lines of **Figure 7**). Their range from the Reference Case in 2025 has narrowed since the November 2019 Needs Assessment Update, as indicated in **Table 4**.

TABLE 4. COMPARISON OF 2025 CAPACITY NEED ACROSS NEED FUTURES IN MW

Need Future	Nov 2019 Needs Assessment	IRP Update
High	1110	737
Reference	697	511
Low	348	292

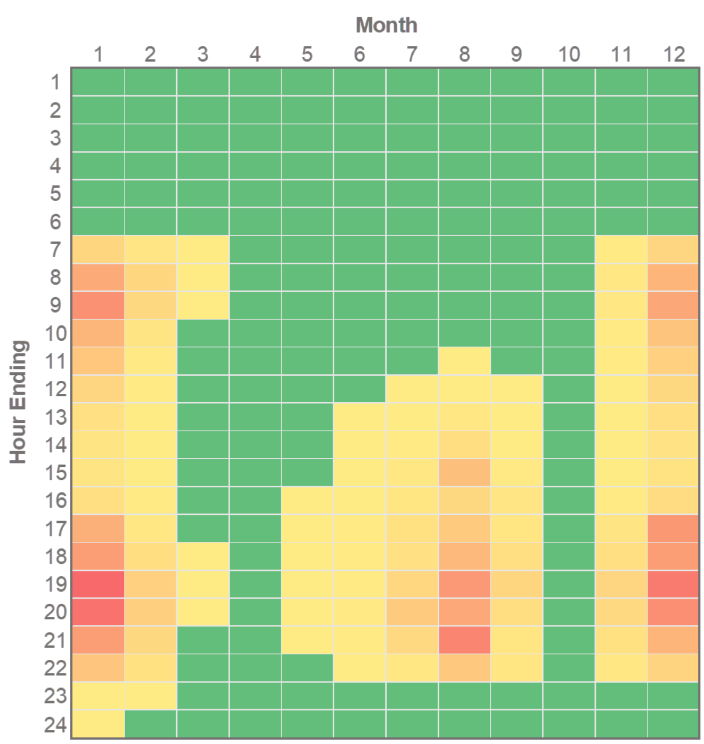
Existing regional resources have the potential to meet some of the identified capacity need; however, their availability is uncertain. The dashed line in **Figure 7** shows the impact of excluding near-term contract expirations from the capacity assessment. The range between the solid and dashed lines increased compared to the November 2019 Needs Assessment due to the Douglas PPA.

FIGURE 7. CAPACITY NEED ACROSS NEED FUTURES AND IMPACT OF CONTRACT EXPIRATIONS



An updated heatmap of the loss-of-load expectation (LOLE) in 2025 is provided in **Figure 8**. The most challenging hours continue to be in the winter evenings, with other high-need hours in winter mornings and summer evenings.

FIGURE 8. REFERENCE CASE LOSS-OF-LOAD EXPECTATION HEATMAP FOR 2025

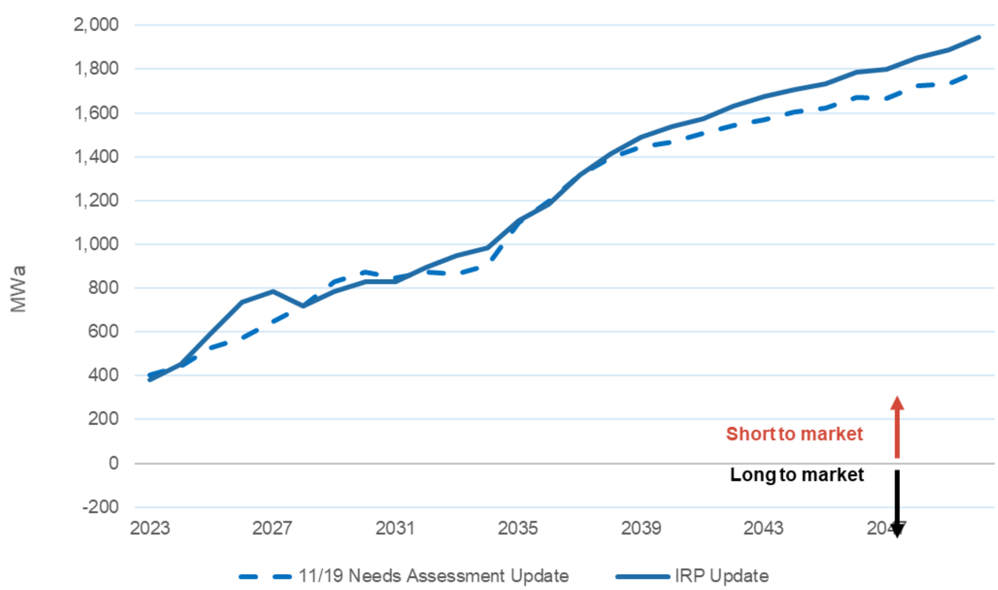


3.5. Energy Position

PGE measures its net market energy position by subtracting the total generation of the Baseline Portfolio from the forecasted load in each future. In the 2019 IRP, the net market energy position was not used to determine resource need. Rather, the market energy position was used to ensure portfolios would not put PGE in a persistently net-long position to the market.[58]

In this IRP Update, PGE has updated the load forecast, the Baseline Portfolio, and the forecasted economic dispatch of the Baseline Portfolio. This allows for an updated view of the company's net market energy position across all price and need futures. This market energy position is displayed below in **Figure 9**. Relative to the November 2019 Needs Assessment Update, the current Reference market energy position shows an increased shortage to market in 2024-2025, followed by a slight decrease beginning in 2029. The near-term market energy position is impacted by both the contract updates (see **Section 3.3.2**) and the updated load forecast (see **Section 3.1**). Further, the update to natural gas prices forecast (see **Section 4.1**) is an important driver of PGE's energy position. In the outer years, the net market shortage increased, primarily due to the increased load forecast.

FIGURE 9. IRP UPDATE REFERENCE CASE NET MARKET SHORTAGE



[58] See 2019 IRP Appendix, Section I.6.3.1 - Portfolio Constraints for more information about ROSE-E's use of energy position. PGE further constrained energy additions through a non-traditional scoring metric that screened out portfolios that added more than 250 MWa of new resources through 2025 and limited the preferred portfolio to no more than 150 MWa of energy additions (see the 2019 IRP, Section 7.2.1 and Section 7.2.2 at 194).

Focusing on 2025, **Table 5** compares the 2025 market position in the Reference Case and the 10th and 90th percentiles for the Filed 2019 IRP, the November 2019 Needs Assessment, and the IRP Update. The energy shortage to market increased for both the Reference Case and the 10th percentile and does not indicate a need to revise the acknowledged renewable action.

TABLE 5. 2025 NET MARKET SHORTAGE COMPARISON, MWA

	Filed IRP	11/19 Needs Assessment Update	IRP Update
Reference Case	580	527	595
10th Percentile	446	285	428
90th Percentile	915	848	887

The traditional energy load-resource balance (LRB) is an analysis that was used historically to consider energy position by evaluating the difference between assumed baseload generation and forecasted load. In Order No. 20-152, the Commission directed PGE to include an energy LRB analysis in the IRP. Accordingly, **Appendix H** provides PGE's updated LRB in the Reference, Low, and High Need cases.

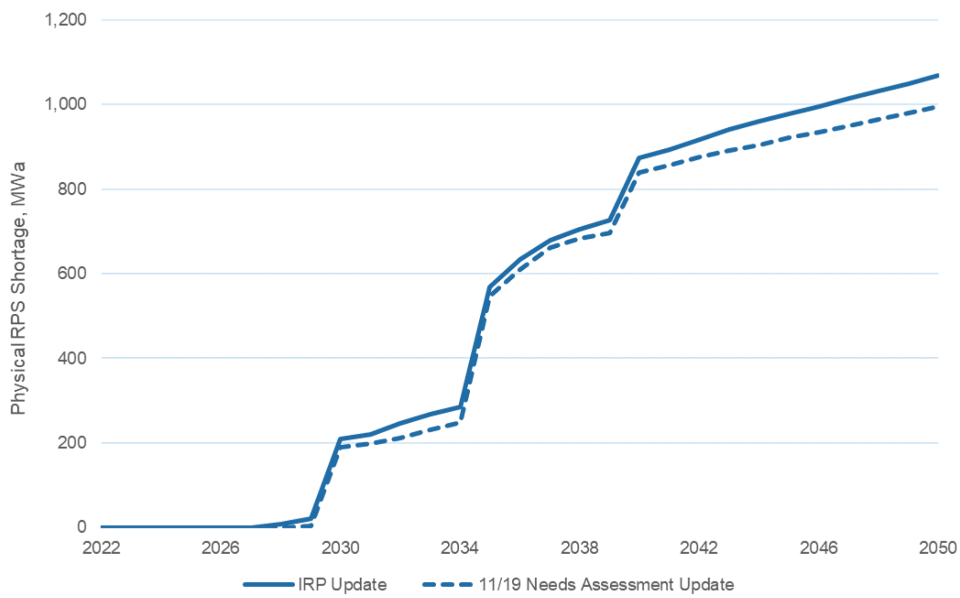
3.6. RPS Position

For this IRP Update, PGE has updated its forecasts of renewable portfolio standard (RPS) compliance obligations and generation of RECs. The June 2020 load forecast displays slightly higher long-term growth rates, which increase RPS compliance obligations.[59] The RECs PGE receives from generation at QFs are expected to be lower relative to the November 2019 Needs Assessment Update.[60] A comparison of the RPS Shortage in the Reference Case is provided in **Figure 10**:

[59] RPS compliance obligations are calculated as a percent of total energy deliveries, increasing from 15% in 2019 to 50% by 2040.

[60] As discussed in Section 3.3.2, the QF update includes anticipated terminations related to the Community Solar Settlement Agreement.

FIGURE 10. COMPARISON OF REFERENCE CASE PHYSICAL RPS SHORTAGE



PGE notes that as discussed in its Reply Comments from LC 73, the renewable action is not driven by RPS compliance.[61] This continues to be the case, as shown in **Section 6.3**, which includes updated portfolio analysis with the RPS obligation removed.

3.7. Sensitivities

The following sensitivities are included to provide additional insights into potential impacts of different assumptions regarding voluntary renewable programs, PURPA QF contracts, and regional capacity.

3.7.1. Voluntary Renewable Program Sensitivity

As discussed in **Section 2.3.7**, when analysis was conducted for this IRP Update, the Baseline Portfolio included approximately 93 MW of resources for the Community Solar program and the executed 162 MW resource for the first tranche of the GEAR program. At that time, an additional 138 MW of GEAR was approved, but resource procurement had not been finalized. The potential impact of this resource was examined through a sensitivity that is summarized in **Table 6**. Including this resource in the portfolio reduces capacity need by 12 MW and reduces the net market shortage by 39 MWa. As noted previously, it does not impact the RPS obligation.

[61] LC 73 PGE's Reply Comments, Section 4.5 – RPS Need, at 49, available at: https://edocs.puc.state.or.us/efdocs/HAC/lc73hac153345.pdf

TABLE 6. VOLUNTARY RENEWABLE PROGRAM SENSITIVITY

Program	Installed Capacity MW	Capacity Contribution MW	Generation MWa	2030 Avoided RPS MWa
GEAR[62]	138	12	39	0

PGE has committed to providing sensitivity analysis of a proposed expansion of the GEAR program beyond the original 300 MW in the next IRP and to provide updated sensitivity analysis with a tariff filing. In addition, PGE looks forward to working with Staff and participants to explore additional analysis aimed at evaluating the long-term impacts of the potential growth of Voluntary Renewable Programs in the public Roundtable process for the next IRP.

3.7.2. PURPA QF Sensitivities

The Baseline Portfolio includes all executed PURPA QF agreements as of the snapshot date. As discussed previously, many of the contracts are for projects that have not yet achieved commercial operations and the contracts provide the seller the ability to delay commercial operations for up to one year. And, as was also discussed, it is possible that new and incremental QF agreements could be executed after the snapshot date or existing agreements could be terminated.

In order to provide informational bookends for considering the potential near-term impacts of either increases or decreases to the quantity of QF resources in the portfolio, low and high QF sensitivities were examined. As in the 2019 IRP, in the low sensitivity, 50 percent of the projects with executed contracts that have not yet achieved commercial operations are assumed to not reach completion. The high sensitivity includes all executed contracts plus all projects actively progressing to execution. The impacts of the sensitivities are summarized in **Table 7**.

[62] The remaining portion of the acknowledged 300 MW of this program not yet included in the Baseline Portfolio.

TABLE 7. RESOURCE NEEDS AND POSITIONS ACROSS QF SENSITIVITIES

Sensitivity	2025 Capacity Need MW	2025 Energy Position MWa	2030 RPS Physical Shortage MWa
Low QF	528	635	250
Base QF	511	595	210
High QF	496	491	106

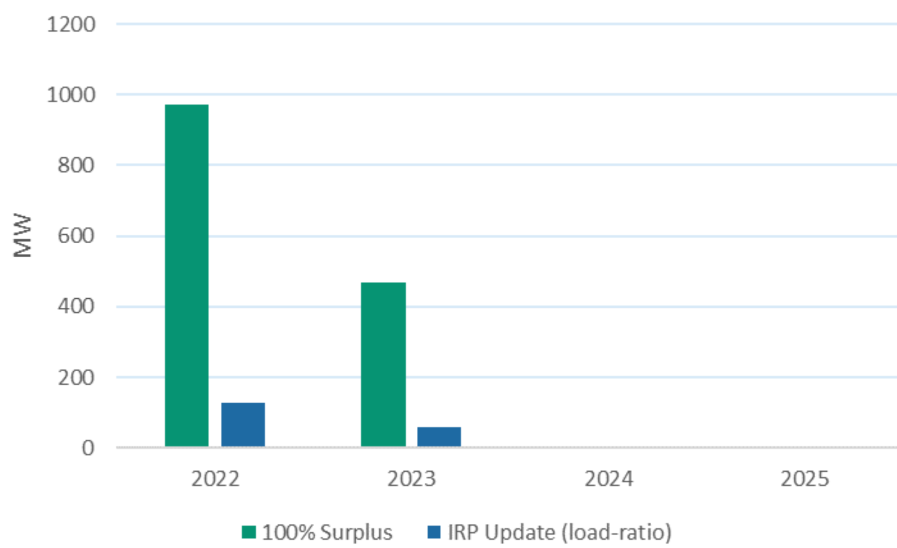
3.7.3. **Regional Capacity Sensitivity**

Section 3.3.3 describes the updates to the Regional Capacity model and provides a comparison of the resulting summer on-peak market capacity assumptions for PGE for the Reference Case.[63] In this section, we provide a sensitivity requested by Staff to examine the impact on the market capacity values of replacing E3's load ratio apportionment methodology with 100 percent of any estimated regional capacity surplus. **Figure 11** compares the Reference Case summer on-peak market capacity values for 2022-2025 using the E3 methodology to those calculated from a 100 percent surplus methodology.

PGE recommends caution when interpreting the results of this market capacity sensitivity. Sensitivities are useful when exploring challenging questions regarding capacity availability. However, PGE does not consider it reasonable or appropriate to apply this assumption within PGE's long-term planning.

[63] As noted in Section 3.3.3, the updated model projects a capacity deficit for winter on-peak in all years and for summer on-peak beginning in 2024.

FIGURE 11. COMPARISON OF MARKET CAPACITY ASSUMPTIONS (SUMMER ON-PEAK, REFERENCE CASE)



4. Wholesale Market Electricity Prices

For this update, PGE updated its natural gas and carbon prices macroeconomic assumptions according to available published data as of June 2020. In both cases, PGE did not change the 2019 IRP methodologies for such forecasts, which are described in Sections 3.2.1[64] and 3.2.2[65] of the 2019 IRP.

4.1. Natural Gas Price Forecast

In IRP modeling, gas prices are derived by using PGE's forward gas trading curve for the shorter term and relying on external fundamental forecasts for the long-term. PGE incorporated uncertainty in natural gas prices by considering low, reference, and high forecast trajectories.

For this IRP Update, gas prices from 2022 through 2024 rely on PGE's forward gas trading curve from the first quarter of 2020. PGE incorporates uncertainty in natural gas prices after 2024 by considering low, reference, and high forecast trajectories.

The Reference Case was updated to the 2019 H2 vintage of Wood Mackenzie gas forecast for the years 2026-2040, with linear interpolation applied in 2025 to transition from the PGE forward gas trading curve. After 2040, the last year of the Wood Mackenzie forecast, PGE simplifies the

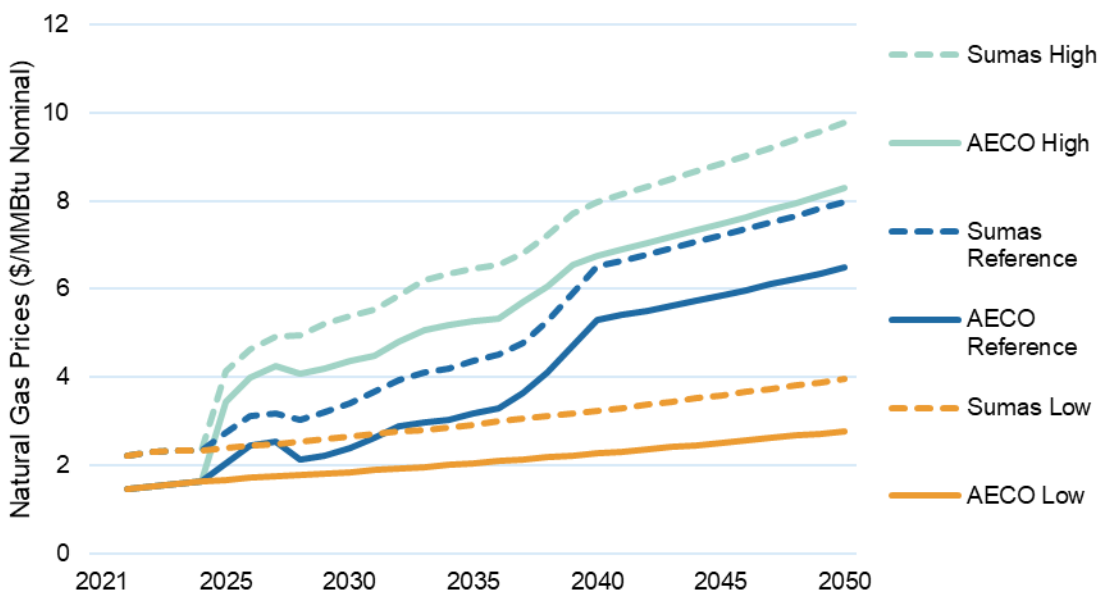
[64] See 2019 IRP, Natural Gas Prices, Section 3.2.1 at 74.
[65] See 2019 IRP, Carbon Prices, Section 3.2.2 at 75.

model by assuming prices will grow at the rate of inflation through 2050, consistent with the 2019 IRP.

To continue to capture a reasonable bound of uncertainty on the low side of the forecast, the Low Gas Price Future assumes natural gas prices grow at the rate of inflation beginning in 2025. This approximates a scenario where near-term market conditions persist.

Both in the 2019 IRP and IRP Update, the High Gas Price Future was modeled using the highest natural gas forecast in the U.S. Energy Information Agency's (EIA) Annual Energy Outlook (AEO).[66] In this IRP Update, the forecast was updated to the 2020 AEO Low Oil and Gas Supply Case for years 2026-2040 with linear interpolation applied in 2025 to transition from the PGE forward gas trading curve.[67] As in the Reference Case, gas prices in the High Gas Price Future grow with inflation after 2040. This entire forecast for 2022-2050 is displayed below in **Figure 12**.

FIGURE 12. UPDATED AECO AND SUMAS HUB PRICES ACROSS GAS PRICE FUTURES



4.2. Carbon Prices

PGE has accounted for future GHG policies since its 2008 IRP as they have the potential to dramatically impact resource economics and strategic procurement. 2019 IRP analysis assumed that carbon pricing in Oregon and Washington began in 2021 and that activities in California

[66] In the 2018 AEO, this scenario was the AEO Low Oil and Gas Resource Technology Case. The name was updated to Low Oil and Gas Supply Case in the 2020 AEO.

[67] Whereas other AEO 2020 natural gas forecasts show production grow at a faster rate than consumption, the Low Oil and Gas Supply series describes gas production and consumption remaining relatively flat due to higher production costs. For more detail see: https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Natural%20Gas.pdf

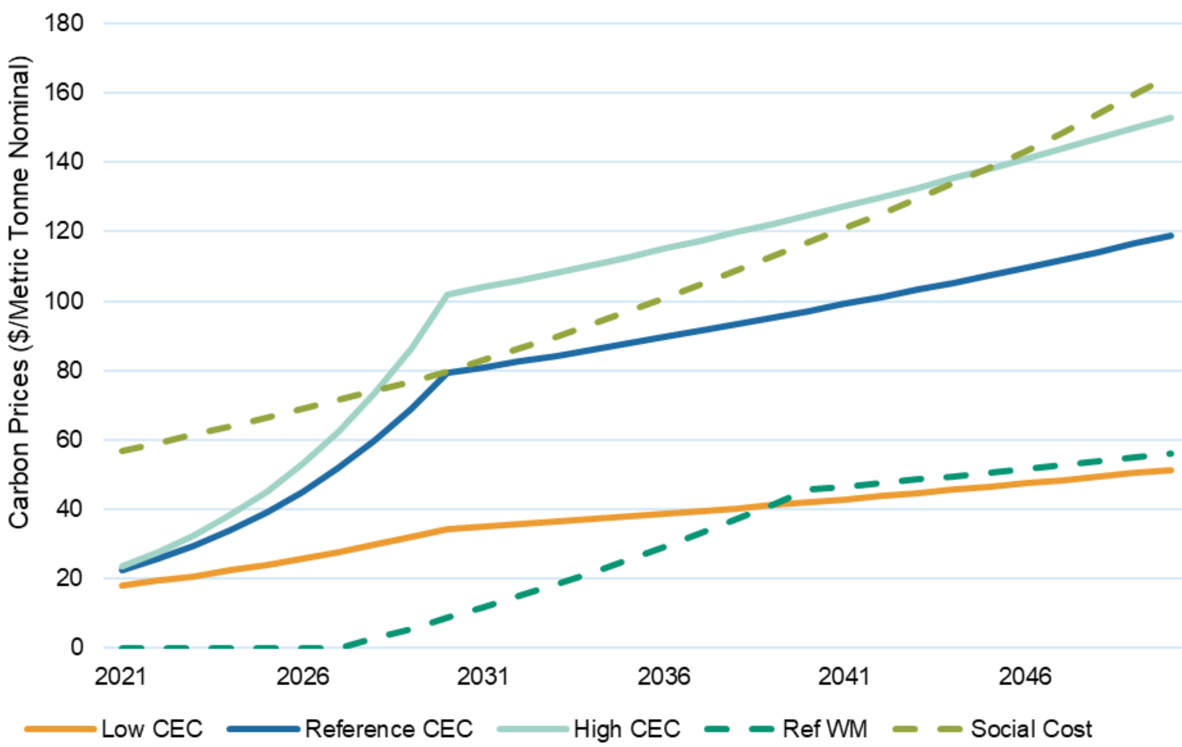
continue to set the allowance price. The analysis used California Energy Commission (CEC) low, mid and high carbon price forecasts.[68]

In this Update, carbon price future assumptions for each region and Carbon Price Future remain the same as those in the 2019 IRP. However, carbon price projections were updated in two ways:

1. The adoption of a carbon price in Oregon and Washington was assumed to be delayed from the beginning of 2021 to 2022.

2. Forecasted carbon prices were updated from the CEC carbon price scenario projections published in the 2017 Integrated Energy Policy Report (IEPR) to those from the 2019 IEPR published in January 2020 and depicted in **Figure 13** below. Relative to the previous iteration of carbon price projections, forecasted trajectories have generally faced a slight reduction for the low and high scenarios, and increased for the reference scenario.

FIGURE 13. UPDATED CARBON PRICE TRAJECTORIES UTILIZED IN THE CARBON PRICE FUTURES



4.3. Wholesale Market Electricity Prices

Consideration of renewable buildout, natural gas prices, carbon prices, and Pacific Northwest (PNW) hydro conditions resulted in 54 distinct Market Price Futures in the 2019 IRP. Updates to

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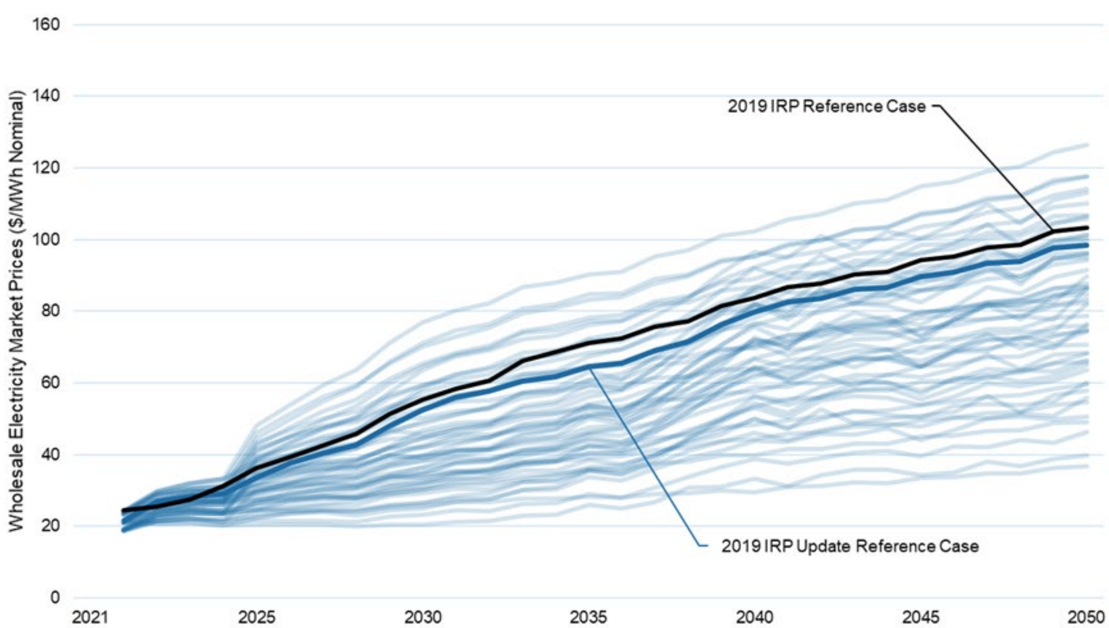
[68] See 2019 IRP Appendix I, 2019 IRP Modeling Details.

the natural gas prices and carbon prices described in the previous sections resulted in updated prices, shown below in **Figure 14**.

A wide range of forecasted wholesale electricity prices across the range of price scenarios continue to be observed. This is due to the range of uncertainty in input factors such as natural gas prices, carbon prices, hydro generation, and renewable buildout.[69] However, due to updates to natural gas price forecasts and carbon price forecasts detailed in the sections above, the resulting electricity price trajectories have also changed. Generally, electricity price forecasts have lowered, driven by the drop in natural gas price forecasts. Below in **Figure 14**, the 2019 IRP Update Reference Case price trajectory is lower than the 2019 IRP Reference Case trajectory. Within the range of 54 Market Price Future trajectories in **Figure 14**, the lowest sets of price trajectories continue to be from High Renewable Buildout Price Futures. The highest price trajectories in the figure are generally from the low PNW hydro Price Futures.

FIGURE 14. ANNUAL WHOLESALE ELECTRICITY MARKET PRICES ACROSS ALL 54 MARKET PRICE FUTURES



[69] For additional information on electricity price forecasting drivers and methodologies, please refer to the 2019 IRP Section 3.2, and Appendix I.

5. Resource Economics

In this IRP Update, PGE has refreshed several key components of resource economics. Some of these updates result from updates to inputs, such as the electricity price forecasts described in **Section 4**. Other specific cost or value components are highlighted in the sub-sections below. These components affect updated resource net costs. The resource net cost is defined as the sum of all fixed, variable, and integration costs net of tax incentives and value provided, including energy, flexibility, and capacity value. These values flow into the portfolio analysis presented in **Section 6**.

5.1. Interconnection Costs

In this IRP Update, PGE included the costs associated with interconnection for each candidate off-system resources. These costs, comprised of the additional interconnection facilities as well as the network upgrades required by the new facilities, were not included in the 2019 IRP. To include these values in the IRP Update, PGE followed the same methodology employed in UM 1728, which extrapolated from the interconnection costs of the Tucannon River wind farm, with minor updates for the inflation and interest assumptions.[70]

There are two components of interconnection facilities, paid on both the customer's and transmission provider's side of the point of interconnection. Customer-side interconnection facilities (also known as gen-ties) costs are estimated using the price per mile per MW value paid for Tucannon, adjusted for inflation. Transmission provider interconnection facilities costs are assumed to be constant among new resource options, and therefore the actual provider costs from Tucannon (escalated for inflation) are applied to each resource. The network upgrade costs are modeled as constant across resource options, with inflation-adjusted Tucannon costs applied to each resource. The associated network upgrade credits are included. The total costs associated with interconnection represent a small portion of total costs; interconnection costs increase total fixed costs across off-system resources by an average of 1.3-4.3%.[71]

5.2. PGE Financial Parameters

This IRP Update uses the same financial parameters as the 2019 IRP, which are summarized in **Table 8**.

[70] The consumer price index and 10-year Treasury Note interest rates are provided in Appendix E.
[71] Battery storage resources are assumed to be located within PGE's balancing authority and are modeled to have no costs of interconnection.

TABLE 8. PGE LONG-TERM FINANCIAL PARAMETERS

Component	Value
Composite Income Tax Rate	27.25%
Incremental Cost of Long-term Debt	4.94%
Long-term Debt Share of Capital Structure	50%
Common Equity Return	9.50%
Common Equity Share of Capital Structure	50%
Weighted Cost of Capital	7.22%
Weighted After-Tax Cost of Capital	6.54%
Long-Term General Inflation	2.05%

PGE made the decision to not update the financial parameters used in the 2019 IRP.[72] The economic outlook since the 2019 IRP has been greatly influenced by the global spread of COVID-19. Long-term financial parameters generally do not move significantly from one IRP/IRP update to the next, as they reflect long-run and typically stable assumptions about the wider economic outlook.[73] With hopes of an effective and widely-available vaccine sometime in 2021, many economic forecasters are predicting the associated economic downturn will not be long-lasting, despite its severe short-run impacts. The most recent update to PGE's financial parameters reflects this more traditional long-run outlook. PGE will be discussing financial assumptions for the next IRP at a future IRP meeting.

5.3. Capacity Contribution - ELCC Values

Resource capacity contribution values were discussed in Section 6.2.3 of the 2019 IRP. For this IRP Update, the capacity contribution analysis was updated to be based on the same snapshot of loads and resources as used for the updated capacity need assessment discussed in **Section 3.4.2**.

An ELCC (effective load carrying capability) is a ratio of the capacity contribution of a resource to its project size. For example, a 100 MW wind resource with a 25 MW capacity contribution value has an ELCC of 25 percent. As discussed in **Section 3.4.1**, the change to reporting capacity contribution values in terms of MW of perfect capacity results in a decrease to ELCC values (all else held constant) and also results in an increase to the cost of capacity (due to a lower ELCC value for the avoided capacity resource).

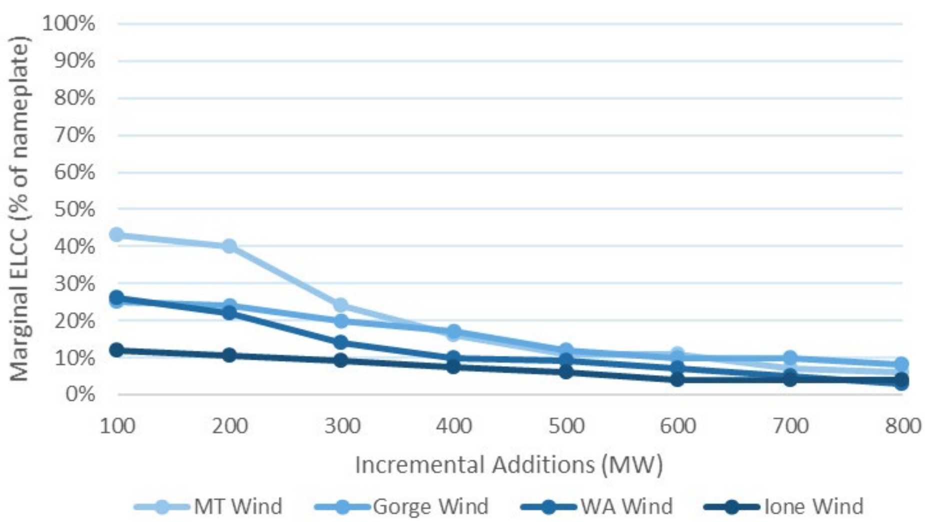
[72] See 2019 IRP, Long-term Financial Assumptions, Section I.2.1 at 341.

[73] A recent exception to this trend is the 2017 tax change, which reduced PGE's corporate tax rate by 32%. This change was included in the 2016 IRP update (filed in 2018), as it represents a large but stable change that PGE expects to continue in the long run. These corporate tax changes were also included in the 2019 IRP: see 2019 IRP, Section I.2.1 at 341.

The marginal ELCC figures included in this section were also shared during Roundtable 20-7.[74] Additionally, the information is provided in tabular format in **Appendix D**.

Figure 15 shows the updated marginal ELCC (effective load carrying capability) values for the four wind resources based on incremental additions of 100 MW. The updated results closely resemble the 2019 IRP values.

FIGURE 15. MARGINAL ELCC FOR WIND RESOURCES



The updated solar marginal ELCC values are provided in **Figure 16**. The value for the first increment of solar decreased relative to the 2019 IRP value for the first increment of solar, primarily due to the large quantity of additional solar resources in the Baseline Portfolio since the analysis for the 2019 IRP (approximately 200 MW). This change parallels the findings from the ELCC analysis from the 2019 IRP, which showed a steep decline across the first 200 MW of solar additions.[75]

Compared to the 2019 IRP, the solar + storage values show a decrease for the initial additions, but a slower decline for incremental additions. The slower decline is likely due in part to the more sophisticated modeling of dispatchable energy-limited resources in Sequoia.

[74] Available at: https://portlandgeneral.com/about/integrated-resource-planning/irp-public-meetings/

[75] The solar ELCC table from the 2019 IRP is provided in Appendix E of this IRP Update for reference.

FIGURE 16. MARGINAL ELCC FOR SOLAR RESOURCES

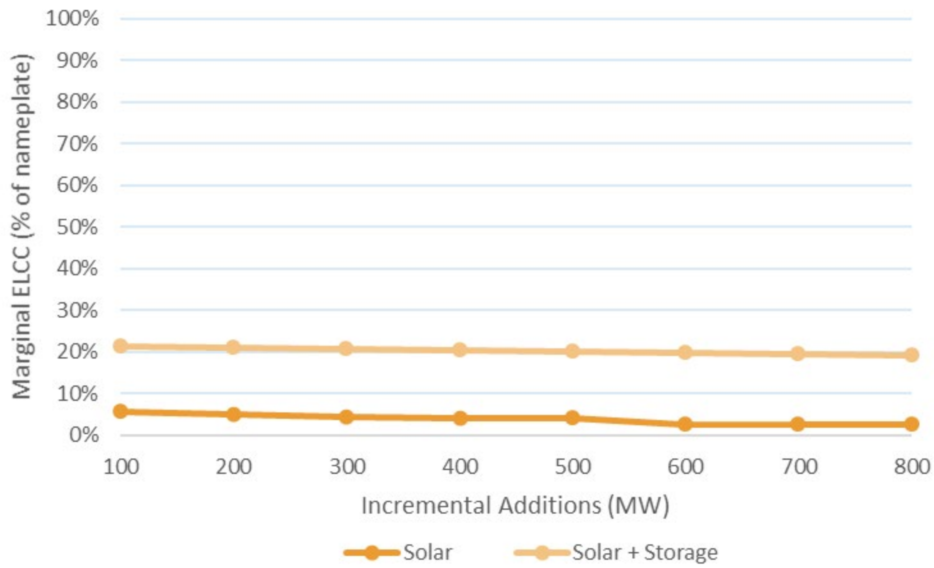
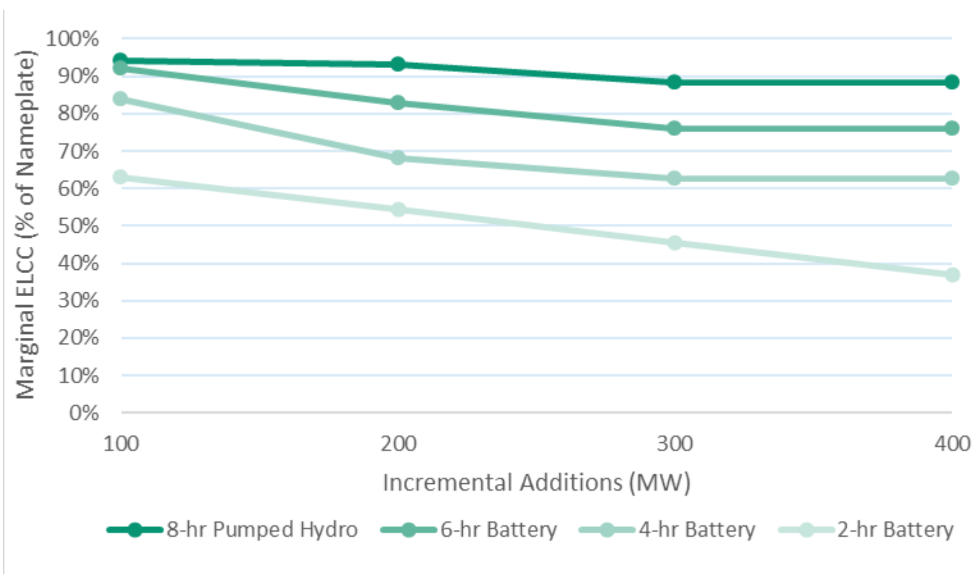


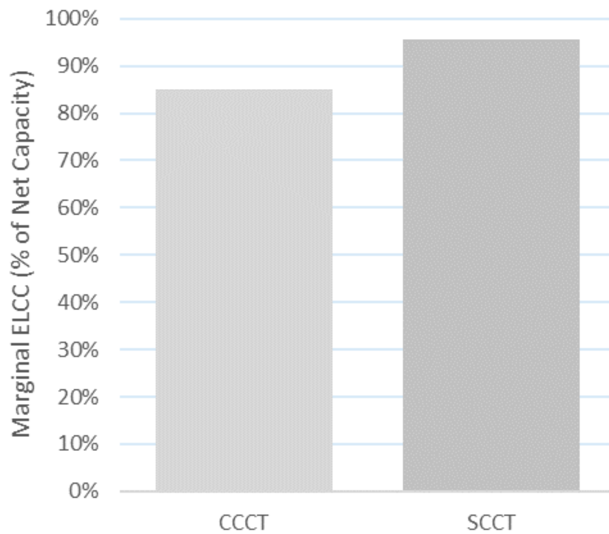
Figure 17 shows the updated marginal ELCC values for storage resources. Their ELCC values increased compared to the 2019 IRP. Again, this is likely due to the more sophisticated treatment in Sequoia.

FIGURE 17. MARGINAL ELCC FOR STORAGE RESOURCES



The updated ELCC values for a combined-cycle combustion turbine (CCCT) and a simple-cycle combustion turbine (SCCT) are provided in **Figure 18**. These declined slightly compared to the 2019 IRP, reflecting the change to reporting capacity need and contribution in terms of perfect capacity.

FIGURE 18. MARGINAL ELCC FOR CCCT AND SCCT RESOURCES



The ELCC values are provided in tabular format in **Appendix D**.

5.4. Cost of Capacity

In the 2019 IRP, the cost of capacity was based on the net cost of the least-cost capacity resource (an SCCT) divided by its ELCC value, based on resource cost estimates from the supply-side study and performance estimates from IRP analysis. In this IRP Update, the cost was updated to reflect the estimated interconnection costs, updated net-energy revenue, and the updated ELCC value. No change was made to the flexibility value. This resulted in an increase to the capacity cost from approximately \$103/kW-yr to \$110/kW-yr (real-levelized, 2020\$).[76] Additional information is provided in **Appendix F**.

The cost of capacity is not the cost that customers pay to acquire capacity through competitive procurement processes. It is a theoretical construct used to translate the capacity contribution of a resource to a dollar value (a capacity value) for the purpose of comparing resources or for uses such as calculating the administratively determined avoided cost payments for resources procured outside of competitive or negotiated processes.

The cost of capacity is distinct from the cost of resources procured through competitive or negotiated processes. In competitive processes, bidders offer prices and terms for resources and PGE compares costs (bid prices), benefit streams (which may include values in addition to capacity), terms, and risks of each resource. Competitive procurements provide the potential to

[76] The \$/kW-yr value from the 2019 IRP is in terms of kW of conventional units while the \$/kW-yr value from the IRP Update is in terms of perfect capacity. The change in reporting convention is discussed in Section 3.4.1.

procure resources at costs below the estimated costs from the IRP and the opportunity to evaluate resource terms and conditions for risk as well as cost.

6. Portfolio Analysis

In this IRP Update, PGE has refreshed its load forecast, capacity assessments, energy and RPS positions, and market price forecasts. Further, the changes in PTC eligibility and addition of interconnection costs discussed above have changed the estimated costs of candidate new resources. With this updated information, PGE refreshed select portfolios to determine whether the main tenets of the portfolio analysis conducted in the 2019 IRP and LC 73 docket still hold. This updated portfolio analysis demonstrates that the 2019 IRP's Action Plan remain the best way to meet system needs over the planning horizon.

6.1. Preferred Portfolio

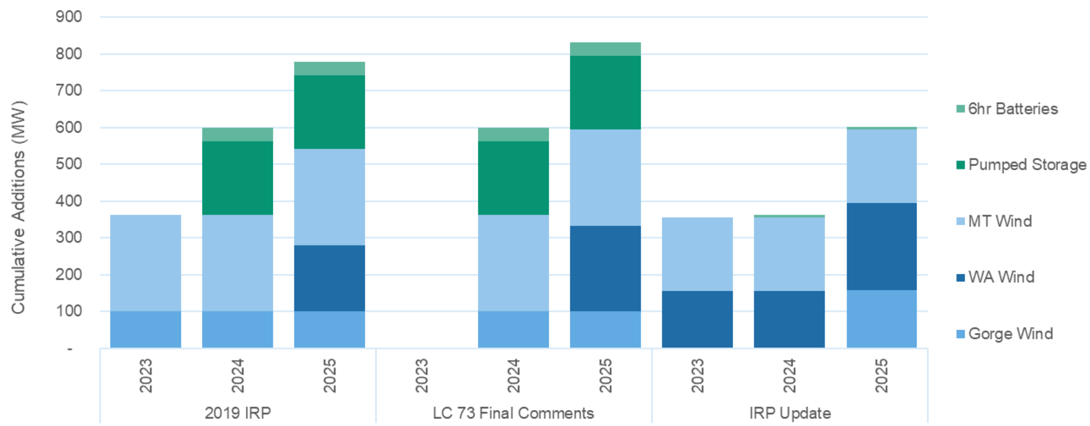
The Mixed Full Clean portfolio was determined to be the preferred portfolio in 2019 IRP portfolio analysis. In PGE's LC 73 Final Comments, the company reevaluated this portfolio with the then-recent extension in PTC eligibility.[77] The main finding was the first renewable acquisition in the preferred portfolio shifting from 2023 to 2024, driven in large part by the PTC extension. **Figure 19** displays the action plan window (2023-2025) additions in the preferred portfolio, where this change can be seen in the left (filed IRP) and middle (LC 73 Final Comments) graphs.

When reevaluating the preferred portfolio using updated information described in the sections above, the results show a similar effect in the opposite direction. The May 2020 PTC change increases the relative attractiveness of a renewable addition that begins generation in 2023. The other tangible difference in resource additions is the reduction of new long-term capacity resources; the signing of the Douglas PPA (described in **Section 3.3.2**) reduces our near-term need. Accordingly, PGE's portfolio optimization model ROSE-E[78] only adds a small amount of new long-term capacity resources (a total of 7 MW of 6-hour batteries in 2024) in the action-plan window.

[77] The Dec 2019 PTC change extended the eligibility of projects to receive 60% PTC to those with commercial operation dates (CODs) on or before December 31st, 2024. See PGE's Final Comments at 28, available at: https://edocs.puc.state.or.us/efdocs/HAC/lc73hac141134.pdf

[78] See 2019 IRP Section I.6 for more details about ROSE-E.

FIGURE 19. MIXED FULL CLEAN ACTION PLAN WINDOW RESOURCE ADDITIONS



Whereas in both the 2019 IRP and LC 73 Final Comments analyses there were large capacity additions made in the action plan window, the IRP Update shows only a minimal amount (7 MW of 6-hr batteries made in 2024). As displayed above in **Figure 19**, near-term capacity needs have decreased with the incorporation of the Douglas PPA. However, a tangible capacity need still exists (**Table 4** in **Section 3.4.2** highlights a Reference Case capacity need of 511 MW in 2025). In the Reference Case, ROSE-E meets this capacity need with the cumulative effect of the renewable additions, the 6-hr batteries mentioned above, and the capacity fill resource. In the action plan window, ROSE-E has the ability in the Reference Case to select the generic capacity fill resource up to the quantity of expiring bilateral capacity agreements, priced one dollar above the cost of capacity described in **Section 5.4**.[79]

The traditional scoring metrics of cost, severity, and variability for the preferred portfolio are displayed below in **Table 9**, as well as the metrics from the previous filings.[80] The IRP Update values exhibit a slight increase in costs relative to the results filed in the LC 73 Comments due to many factors, including increased load growth. Further, the IRP Update analysis shows a substantial reduction in both risk metrics, driven in large part by the reduction in the range of forecasted natural gas prices, which drives down cost in the higher-cost futures.

TABLE 9. CHANGE IN PREFERRED PORTFOLIO TRADITIONAL SCORING METRICS

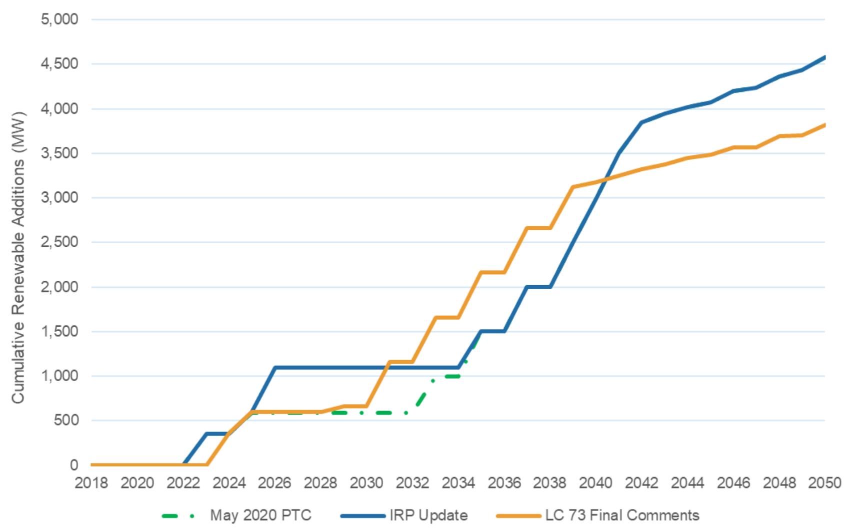
	2019 IRP	LC 73 Final Comments	IRP Update
Cost ($ millions)	25,740	25,617	25,713
Variability ($ millions)	3,614	3,623	2,882
Severity ($ millions)	31,004	30,851	29,649

[79] See 2019 IRP Section 7.1.1.1 – Resource Adequacy for more information.

[80] For more information on traditional and non-traditional scoring metrics, see the 2019 IRP's Section 7.2.1 – Scoring Metrics.

As mentioned above in **Section 2.4.2**, this IRP Update has incorporated the most recent extension to the PTCs (December 2020). When minimizing long-term portfolio costs, ROSE-E elects in the Reference Case to add 500 MW of renewables in 2026, which is the upper limit of cumulative capacity addition in a single year.[81, 82] As shown below in **Figure 20**, the cumulative renewable additions in 2026 bring forward additions the Reference Case otherwise would have made in 2033 and 2035.

FIGURE 20. PTC EXTENSION EFFECT ON CUMULATIVE RENEWABLE ADDITIONS IN THE PREFERRED PORTFOLIO REFERENCE CASE



The updates incorporated into this IRP Update described above impact resource additions and net market energy position, both of which impact portfolio emissions. **Figure 21** shows the forecasted emissions from the Preferred Portfolio for the Reference Case.

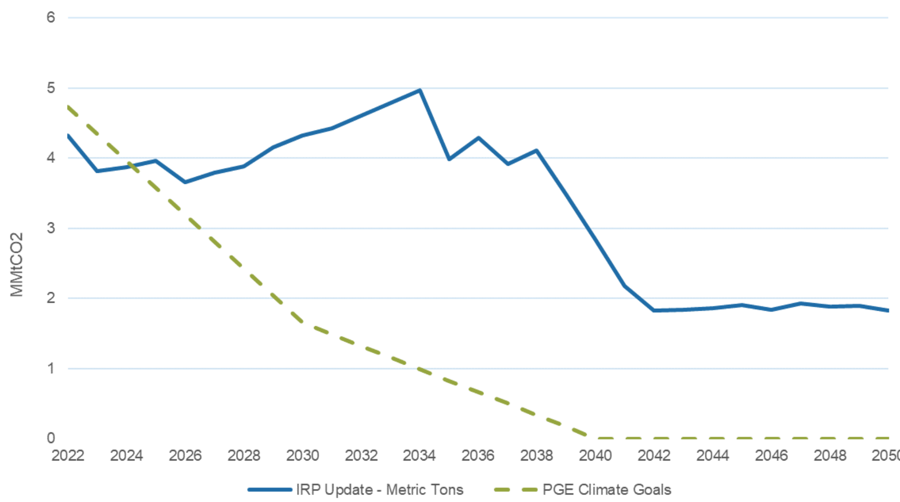
This analysis maintains the same forecasts for energy efficiency and distributed flexibility as the 2019 IRP. Additionally, it maintains the same treatment of Colstrip. Further, in this IRP Update PGE has not introduced new emission constraints or decarbonization methodologies. However, we note that this will be a central focus of the 2022 IRP as PGE works to incorporate our recently announced climate goals, address the OPUC workplan for EO-04, incorporate updated Colstrip information, consider continued expansion of voluntary individual and collective renewable programs, and respond to any additional state and federal policies.

[81] After the action plan window (2023-2025), ROSE-E determines optimal resource additions for every need-price-technology cost combination. Accordingly, there are 270 different choices of resource additions for the preferred portfolio in 2026, the year to which PTC eligibility was extended in the December 2020 PTC change. Of those futures, 152 added some quantity of renewables in 2026, and 104 determined the most optimal decision was to add the maximum amount of renewable capacity (500 MW) in 2026.

[82] In the 2019 IRP, ROSE-E limited energy resource additions to be every-other year between 2025-2040; using the same methodology would preclude any additions in 2026. Accordingly, PGE relaxed this assumption to allow energy resource additions in 2026, which allows an evaluation of the recent PTC change.

Figure 21 also includes the straight-line trajectory of our new climate goals and this shows that while significant progress has been made in the 2019 IRP to address decarbonization, much work remains to be done in the 2022 IRP.

FIGURE 21. EMISSIONS IN PREFERRED PORTFOLIO'S REFERENCE CASE



To reflect the urgency in addressing climate change and to meet customers' desire to be served with increasingly clean, renewable electricity, PGE is committed to reducing greenhouse gas emissions associated with the power we serve customers by at least 80 percent below 2010 levels by 2030. We also set an aspirational goal of zero greenhouse gas emissions associated with the power we serve customers by 2040.

PGE looks forward to engaging on all these topics and their impacts on long-term planning, portfolio development, and emissions forecasts during our participant conversations and meetings throughout the development of the 2022 IRP.

6.2. Near-term Renewable Addition

In response to questions from Staff, PGE prepared analysis for Final Comments that compared the preferred portfolio to a portfolio without the ability to add renewable resources in 2023-2025.[83] The analysis was updated for this IRP analysis and the results are summarized below in **Table 10**. Relative to the preferred portfolio, the Mixed Full Clean, No Renewable Addition (RA)[84] portfolio displays higher cost, as the portfolio is unable to take advantage of federal tax credits available between 2023-2025 to lower costs. Further, both the variability and severity metrics increase, as the increased reliance on market purchases in earlier years leads to a relatively wider spread of higher cost futures. These results suggest the benefits of near-term

[83] See PGE Final Comments, Section 6.4 at 40.

[84] In this portfolio, no renewable resource additions can be added in the action plan window (2023-2025).

acquisition of renewables outlined in the action plan are still in the interest of the company and our customers.

TABLE 10. PREFERRED PORTFOLIO WITH AND WITHOUT NEAR-TERM (2023-2025) RESOURCE ADDITIONS

	Mixed Full Clean	Mixed Full Clean, No RA	Difference
Cost ($ millions)	25,713	26,069	356
Variability ($ millions)	2,882	2,967	86
Severity ($ millions)	29,649	30,102	453

6.3. Preferred Portfolio RPS Sensitivity

In PGE's LC 73 Reply Comments, PGE included a sensitivity that tested the portfolio implication of removing the RPS obligation.[85] Results suggested that near-term actions were not driven by our RPS obligation, as the least-cost and -risk portfolio choices remained even with the RPS obligation removed. In this IRP Update, PGE again evaluated the preferred portfolio with no RPS obligation to determine whether this earlier result would hold with the updated information. Facing no RPS obligation, ROSE-E selects the same near-term resource additions for the preferred portfolio, and the remaining resource addition pathways are nearly identical.[86] This reinforces the earlier finding that RPS compliance is not a driver of the Renewable Action proposed and acknowledged in the 2019 IRP. That RPS compliance is not a driver in the action plan suggests that these resources are the best choice for our customers from an economic as well as environmental standpoint.

6.4. Energy-Unconstrained Optimized Portfolios

In the 2019 IRP and in Final Comments, PGE provided results from Optimized portfolios (those without portfolio constraints but with system constraints).[87] While these portfolios were appropriately screened out from the top performing portfolios, they provide insight into a bookend consideration of what would be selected if the only objective were to minimize long-term costs. The analysis of the optimized portfolio from Final Comments showed that the impact of the December 2019 PTC extension was a delay of the initial renewable addition from 2023 to 2024, but no change to the total quantity added through 2025, approximately 1,350 MW (see **Figure 22** below).

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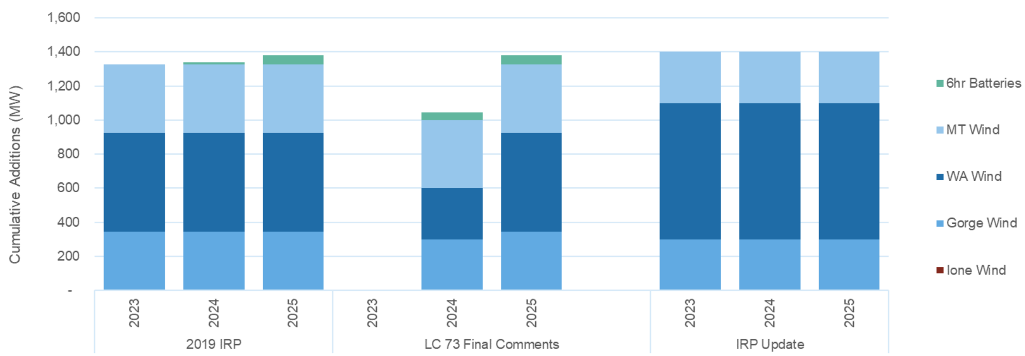
[85] This sensitivity was included to respond to concerns from OPUC Staff, Renewable Northwest, and the Alliance of Western Energy Consumers about the impact of RPS need. For more information, see LC 73 PGE Reply Comments, Section 4.5.
[86] Capacity additions in the Reference Case only differed in 2050.
[87] A portfolio constraint is a constraint specific to the given portfolio. For example, we can tell ROSE-E that this given portfolio must add 250 MW in 2037. This constraint does not impact other portfolios. On the other hand, a system constraint is placed on all portfolios. For example, we say that all portfolios must meet our RPS obligation.

PGE refreshed this analysis for the IRP Update, capturing the recent changes to PTC eligibility, as well as the updated load, resource, and market price information. As with the Preferred Portfolio, the May 2020 PTC update resulted in the first renewable resource additions occurring in 2023 to capture the higher PTC rate, which can also be seen in **Figure 22**.

As with Final Comments, these findings continue to support the high-level conclusion that there is a strong economic signal to pursue near-term renewable additions while federal tax credits remain available.

FIGURE 22. MIN AVERAGE LONG-TERM COST, ALL CLEAN RESOURCE ADDITIONS



7. Conclusion

Through this IRP Update, we have examined the impact of updated information including load forecasts (inclusive of customer demand impacts of COVID-19), recent resource additions, PTC eligibility, interconnection costs, and market prices on our need and position assessments, sensitivities, capacity contribution, and portfolio analysis. We have also engaged collaboratively with OPUC Staff and participants through our Roundtable process in 2020 to proactively share and discuss findings from our IRP Update analysis, as well as to begin discussions for the 2022 IRP.[88] Through this process, we have found that while actions such as the Douglas PPA have reduced our 2025 capacity need, substantial need remains. Further, the updated PTC information also has not changed the core findings of the preferred portfolio. We also determined that the substantial increase in solar resources in our portfolio has reduced the marginal ELCC value of incremental solar resources. While this does not impact the findings of the preferred portfolio, it does impact the appropriate value for solar resources in avoided cost pricing.

We believe the 2019 IRP Action Plan continues to represent the best path forward for our customers as we continue to build the clean energy future they want, and welcome feedback

[88] PGE held eight Roundtable meetings in 2020 after Commission acknowledgment of the 2019 IRP on March 16, 2020. All meeting materials are available on PGE's webpage and a list of agenda topics is provided in Appendix A.

from our community and participants during the coming review. The 2019 Action Plan reflects the values of our company and our customers, is responsive to participant feedback, and embraces positive change shaping the electric utility industry. The actions approved March 16, 2020 by the Commission remain in the best interest of our customers: selecting low-cost, clean technology and mitigating risk.

PGE asks the Commission to acknowledge this 2019 IRP Update so that we may incorporate the updated information in our May 1 avoided cost filing to more accurately reflect the value of PURPA resources in our QF pricing.

The world is in an unexpected place right now and will continue to experience uncertainty in the coming year. These experiences highlight the continued importance of flexibility, adaptability, and the ability to address uncertainty in long-term planning processes. A key focus of our next IRP cycle will be on expanded consideration and analysis surrounding greenhouse gas emissions, climate adaptation, and clean energy standards to address goals of Oregon, our communities, and our company as we fulfill our fundamental mission of delivering the clean, reliable, and affordable power our customers need. PGE is committed to leading the way to a clean energy future on behalf of customers, optimizing the system for all through a smarter, more resilient grid. Our team is looking forward to continued collaboration and forward-thinking innovation as we work with participants and Commission Staff to develop the 2022 IRP. As discussed in this update, the 2022 IRP public process, enabling studies, and analytical work are all underway. PGE would like to thank participants for their early engagement in this process.

The IRP Team deeply appreciates the humanity, kindness, and engagement that the IRP participants have shown as we work to continue and transition a meaningful planning and analysis process to a virtual setting. In our 2022 IRP process, we intend to facilitate open communication with the IRP's existing participants and remain committed to additional efforts for increased outreach across our customers' communities.

APPENDICES

A. PGE IRP Roundtable Dates and Topics

The topics covered in PGE's 2020 Roundtables are provided below. In these meetings, PGE shared information with participants about most of the updates and analysis included in this IRP Update. Materials from these meetings are available.[89]

March 19, 2020: Roundtable 20-1

TOPICS: *Capacity assessment (with introduction to Sequoia); Energy efficiency*

April 14, 2020: Roundtable 20-2

TOPICS: *Transmission; Integration cost drivers enabling study; Climate adaptation enabling study*

May 20, 2020: Roundtable 20-3

TOPICS: *Capacity assessment: preliminary Sequoia model development workshop; Climate adaptation enabling study*

July 29, 2020: Roundtable 20-4

TOPICS: *Background on Integrated Resource Planning; Community values discussion*

August 19, 2020: Roundtable 20-5

TOPICS: *Price futures; Capacity assessment Sequoia baseline; Supply-side options*

October 28, 2020: Roundtable 20-6

TOPICS: *Load forecast for IRP update; Capacity need, RPS position, energy position; Market prices for IRP update*

November 18, 2020: Roundtable 20-7

TOPICS: *Change to production tax credits for 2019 IRP update; Interconnection costs (updated for 2019 IRP update); Capacity contributions; LUCAS 101; ROSE-E 101*

December 10, 2020: Roundtable 20-8

TOPICS: *2019 IRP update: draft portfolio analysis; 2020 distributed energy resources (DER) and flex load potential study*

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[89] See: https://portlandgeneral.com/about/integrated-resource-planning/irp-public-meetings/

B. Annual Energy Deliveries for 2015-2019

In response to a request from Staff, **Table 11** provides customer demand and associated growth rates from 2015 through 2019. The values are provided based on net system weather-adjusted cycle energy deliveries, inclusive of deliveries on direct access schedules to best reflect trends, as requested. **Table 12** provides growth in customer count.

TABLE 11. CYCLE ENERGY DELIVERIES (THOUSAND MWH, WEATHER ADJUSTED)

	CYCLE ENERGY DELIVERIES (THOUSAND MWH, WEATHER ADJUSTED)					GROWTH RATE (ANNUAL PERCENTAGE CHANGE)			
	2015	2016	2017	2018	2019	2016	2017	2018	2019
Residential	7,567	7,603	7,498	7,572	7,404	0.5%	-1.4%	1.0%	-2.2%
Commercial	7,510	7,405	7,447	7,495	7,355	-1.4%	0.6%	0.6%	-1.9%
Industrial	4,574	4,138	4,270	4,331	4,608	-9.5%	3.2%	1.4%	6.4%
Total	**19,651**	**19,147**	**19,215**	**19,398**	**19,367**	**-2.6%**	**0.4%**	**1.0%**	**-0.2%**

TABLE 12. CUSTOMER COUNT (ANNUAL AVERAGE, NET SYSTEM)

	AVERAGE CUSTOMER COUNT					GROWTH RATE (ANNUAL PERCENTAGE CHANGE)			
	2015	2016	2017	2018	2019	2016	2017	2018	2019
Residential	742,467	752,365	762,211	772,389	779,673	1.3%	1.3%	1.3%	0.9%
Commercial	105,802	106,773	107,855	109,107	110,084	0.9%	1.0%	1.2%	0.9%
Industrial	255	258	267	270	262	1.2%	3.5%	1.1%	-3.0%
Total	**848,524**	**859,396**	**870,333**	**881,766**	**890,019**	**1.3%**	**1.3%**	**1.3%**	**0.9%**

C. Behind-the-meter PV from 2015-2019

In response to a request from Staff, **Table 13** provides the amount of behind-the-meter PV on PGE's system from 2015-2019. The values provided are MW_{DC} at year-end.

TABLE 13. BEHIND-THE-METER PV ON PGE'S SYSTEM, YEAR-END, MW_{DC}

Year	MW_{DC}
2015	57
2016	69
2017	81
2018	94
2019	108

D. IRP Update ELCC Tables

This section provides the tabular format of the marginal ELCC figures from **Section 4.3**.

TABLE 14. MARGINAL ELCC FOR WIND RESOURCES

Incremental 100 MW Additions	Gorge Wind	Ione Wind	WA Wind	MT Wind
100	25.0%	12.0%	26.0%	43.0%
200	24.0%	10.5%	22.0%	40.0%
300	20.0%	9.0%	14.0%	24.0%
400	17.0%	7.5%	10.0%	16.0%
500	12.0%	6.0%	9.0%	11.0%
600	10.0%	4.0%	7.0%	11.0%
700	10.0%	4.0%	5.0%	7.0%
800	8.0%	4.0%	3.0%	6.0%

TABLE 15. MARGINAL ELCC FOR SOLAR RESOURCES

Incremental 100 MW Additions	Solar	Solar + Storage
100	5.5%	21.3%
200	5.0%	20.9%
300	4.5%	20.6%
400	4.0%	20.3%
500	4.0%	20.0%
600	2.7%	19.6%
700	2.7%	19.3%
800	2.7%	19.0%

TABLE 16. MARGINAL ELCC FOR STORAGE RESOURCES

Incremental 100 MW Additions	2-hr Battery	4-hr Battery	6-hr Battery	8-hr Pumped Hydro
100	63.0%	84.0%	92.0%	94.0%
200	54.3%	68.0%	83.0%	93.0%
300	45.7%	62.5%	76.0%	88.5%
400	37.0%	62.5%	76.0%	88.5%

TABLE 17. MARGINAL ELCC FOR UNIT SIZE ADDITIONS OF CCCTS AND SCCTS

Resource	ELCC
CCCT	85.0%
SCCT	95.5%

E. 2019 IRP Solar ELCC Table

Table 18 provides the solar marginal ELCC values from the 2019 IRP. These values were used to create Figure 6-4 in the 2019 IRP.

TABLE 18. 2019 IRP MARGINAL ELCC FOR SOLAR RESOURCES

Incremental 100 MW Additions	Solar
100	15.8%
200	10.2%
300	7.2%
400	4.8%
500	3.6%
600	2.6%
700	2.1%
800	2.0%

F. Additional Resource Cost Information

This appendix provides additional detail about resource cost information from the IRP Update.

For the interconnection costs discussed in **Section 5.1**, the escalation of Tucannon's costs from 2013 to 2018 was based on the consumer price index values provided in **Table 19**.

TABLE 19. CONSUMER PRICE INDEX[90]

Year	CPI
2010	218.06
2011	224.94
2012	229.59
2013	232.96
2014	236.74
2015	237.02
2016	240.01
2017	245.12
2018	251.11
2019	255.66

The interconnection cost calculations for network upgrade credits utilized the 10-year Treasury Note interest rates provided in **Table 20**.

[90] US Bureau of Labor Statistics, Consumer Price Index, CPI for All Urban Consumers, available at: https://www.bls.gov/

TABLE 20. 10-YR TREASURY NOTE INTEREST RATES[91]

Year	Return
2018	2.91%
2019	2.14%
2020	0.88%
2021	0.89%
2022	1.12%
2023	1.37%
2024	1.63%
2025	1.90%
2026	2.25%
2027	2.56%
2028	2.82%
2029	3.02%
2030	3.18%

Table 21 provides the components of the cost of capacity discussed in **Section 5.4**. The net cost of an SCCT is divided by its ELCC value to calculate a cost of perfect capacity.

TABLE 21. IRP UPDATE COST OF CAPACITY

Item	Values	Units
Fixed Cost	$110.02	$/kW-yr 2020$
Flexibility Value	($4.82)	$/kW-yr 2020$
Net Energy Value	($0.39)	$/kW-yr 2020$
ELCC Value	95.5%	%
Cost of Capacity	$109.74	$/kW-yr 2020$

[91] From the Congressional Budget Office (CBO) July 2020 Report. See: https://www.cbo.gov/system/files/2020-07/51135-2020-07-economicprojections.xlsx

G. PTC Tables

The PTC has been changed three times since the filing of the 2019 IRP.[92] The relevant information for tax credit eligibility is the date construction begins and the project's COD. A resource begins production (labeled IRP Start below) in the year following COD. The original IRP PTC eligibility levels as well as their first change are show below in **Table 22**. This December 2019 change extended the 60% PTC to 2025.[93]

TABLE 22. ORIGINAL PTC ELIGIBILITY LEVELS WITH DEC 2019 EXTENSION (RED)

Construction Began	COD on or Before	IRP Start	2019 Filed IRP	12/2019 PTC
2016	12/31/2020	2021	100%	100%
2017	12/31/2021	2022	80%	80%
2018	12/31/2022	2023	60%	60%
2019	12/31/2023	2024	40%	60%*
2020	12/31/2024	2025	0%	60%

The May 2020 extension (**Table 23**) added an extra year of eligibility for projects that began production in 2021 and 2022, increasing the number of years a project had to reach COD (from four to five years).

TABLE 23. MAY 2020 PTC EXTENSION (RED)

Construction Began	COD on or Before	IRP Start	PTC Level
2016	12/31/2021	2022	100%
2017	12/31/2022	2023	80%
2018	12/31/2022	2023	60%
2019	12/31/2023	2024	60%
2020	12/31/2024	2025	60%

The December 2020 extension (**Table 24**) allowed an extra year for projects to begin construction and start generation.

[92] The ITC has also changed since the 2019 IRP. However, as solar, solar plus storage, and geothermal resources were considered but not selected in the eligible timeframe, the impact of the corresponding ITC changes (timed the same as PTCs, with differing magnitudes) cannot be seen in changes to resource additions.

[93] The PTC extension only extended the 60% level of PTC eligibility to resources that began construction in 2020: resources that began construction in 2019 with a COD before the end of 2023 still only qualify for the 40% PTCs. However, given the fact that developers have some flexibility in determining CODs and a strong financial incentive to qualify for the 60% PTC, PGE made a modeling decision to let ROSE-E assume that projects that would start generating in 2024 would still be able to qualify for the 60% PTC.

TABLE 24. DECEMBER 2020 PTC EXTENSION (RED)

Construction Began	COD on or Before	IRP Start	PTC Level
2016	12/31/2021	2022	100%
2017	12/31/2022	2023	80%
2018	12/31/2022	2023	60%
2019	12/31/2023	2024	60%
2020	12/31/2024	2025	60%
2021	12/31/2025	2026	60%

H. Projected Annual Average Energy Load-Resource Balance

The traditional energy load-resource balance (LRB) provides a view of a system's energy position based on a concept of annual available energy from the resources in the portfolio compared to the average annual load. **Table 25** provides the updated energy LRBs for the Reference, Low, and High Need Futures based on the same methodology as the 2019 IRP.[94]

TABLE 25. IRP UPDATE ENERGY LOAD-RESOURCE BALANCE (REFERENCE, LOW, AND HIGH NEED), MWA

										Reference
	2021	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Gas	954	954	954	956	954	954	954	956	954	954
Coal	263	263	263	264	263	263	0	0	0	0
Hydro	529	528	521	528	427	275	261	260	259	259
Wind+Solar	438	537	559	559	558	547	494	360	334	334
Other Contracts	31	31	31	31	31	26	8	0	0	0
EE	41	70	97	124	150	280	400	515	629	742
Total Resources	**2256**	**2383**	**2425**	**2462**	**2383**	**2345**	**2117**	**2092**	**2175**	**2289**
Load	**2177**	**2222**	**2284**	**2346**	**2402**	**2678**	**2958**	**3248**	**3549**	**3853**
Energy deficit/(surplus)	**(79)**	**(161)**	**(141)**	**(116)**	**19**	**334**	**841**	**1157**	**1374**	**1564**

										Low
	2021	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Gas	954	954	954	956	954	954	954	956	954	954
Coal	263	263	263	264	263	263	0	0	0	0
Hydro	529	528	521	528	427	275	261	260	259	259
Wind+Solar	438	537	559	559	558	547	494	360	334	334
Other Contracts	31	31	31	31	31	26	8	0	0	0
EE	41	70	96	119	141	255	350	437	522	606
Total Resources	**2256**	**2383**	**2424**	**2457**	**2374**	**2320**	**2068**	**2014**	**2068**	**2152**
Load	**2145**	**2161**	**2193**	**2221**	**2243**	**2342**	**2436**	**2534**	**2641**	**2754**
Energy deficit/(surplus)	**(111)**	**(221)**	**(231)**	**(236)**	**(132)**	**23**	**368**	**520**	**573**	**602**

										High
	2021	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Gas	954	954	954	956	954	954	954	956	954	954
Coal	263	263	263	264	263	263	0	0	0	0
Hydro	529	528	521	528	427	275	261	260	259	259
Wind+Solar	438	537	559	559	558	547	494	360	334	334
Other Contracts	31	31	31	31	31	26	8	0	0	0
EE	41	70	97	124	150	280	400	515	629	742
Total Resources	**2256**	**2383**	**2425**	**2462**	**2383**	**2345**	**2117**	**2092**	**2175**	**2289**
Load	**2206**	**2277**	**2368**	**2461**	**2550**	**2988**	**3413**	**3842**	**4279**	**4713**
Energy deficit/(surplus)	**(50)**	**(106)**	**(57)**	**(1)**	**167**	**643**	**1296**	**1750**	**2103**	**2424**

[94] As described in Appendix G.3 of the 2019 IRP.

I. Preferred Portfolio Details

In the 2019 IRP, PGE designed the preferred portfolio as an optimized portfolio with constraints according to three principles[95] and these same principles were applied to the preferred portfolio for this IRP Update:

- Customer Resources: Include all cost-effective energy efficiency as well as DER adoption and participation assumptions consistent with the DER Study
- Renewable Resource Additions: Allow up to 150 MWa of additional renewable resources in 2023-2024 and no more than 250 MWa through 2025.[96]
- Capacity Resource Additions: Allow new capacity resource additions through 2025 from technologies that do not emit greenhouse gases.

The preferred portfolio has the same customer resource additions as it did in the filed IRP, displayed below by need future in **Table 26**.

TABLE 26. CUSTOMER RESOURCE ACTIONS IN THE PREFERRED PORTFOLIO

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency	108	133	157	111	140	167	108	133	157
Demand Response									
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	4	7.3	9.1	11.2	1.1	1.6	2.2

Optimizing based on the updated information described in previous sections, the preferred portfolio adds a total of 150 MWa of Southeast Washington and Montana wind in 2023. As shown in **Table 27** below, another addition of Southeast Washington is made in 2025, along with a 64 MWa of Gorge wind resources. These additions do not vary by need, as the resource additions made by ROSE-E in the action plan window are fixed across all need, price, and technology cost futures.

[95] See PGE's 2019 IRP at 194.

[96] The constraint of no more than 250 MWa through 2025 was included in the Preferred Portfolio in analysis for PGE's Final Comments and IRP Update.

TABLE 27. 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)	0	0	64	0	0	64	0	0	64
SE WA Wind (MWa)	66	66	102	66	66	102	66	66	102
MT Wind (MWa)	84	84	84	84	84	84	84	84	84
Total Renewables	150	150	250	150	150	250	150	150	250

The preferred portfolio meets its near-term capacity needs with the combination of the capacity fill resource and a of a small quantity of 6-hr batteries, shown below in **Table 28**. In the action plan window, the capacity fill resource is limited in the Reference Case to the size of expiring bilateral capacity agreements and is priced just above the net cost of a simple-cycle combustion turbine.

TABLE 28. CUMULATIVE DISPATCHABLE CAPACITY RESOURCE ACTIONS IN THE PREFERRED PORTFOLIO

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Storage Resources									
6hr Batteries (MW)	0	7	7	0	7	7	0	7	7
Capacity Fill (MW)	0	71	330	0	0	111	118	261	556
Total Dispatchable Capacity (MW)	0	78	337	0	0	118	118	268	563

J. 2019 IRP Action Plan

The 2019 IRP action plan contains three main components: customer resource actions, renewable actions, and capacity actions. Each of these three components acknowledged subject to conditions by the Commission in March 2020.[97] Based on the updated analysis in this IRP Update, PGE affirms that these actions continue to be in the best interest of customers.

The 2019 IRP action plan is presented below along with the Commission's conditions.

J.1. Customer Resources

Customer Resource Actions

Action 1A. Seek to acquire all cost-effective energy efficiency.

Action 1B. Seek to acquire all cost-effective and reasonable distributed flexibility.

Modifications agreed to by Staff and PGE and accepted by the Commission:[98]

> Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.
>
> Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.
>
> Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and to consider adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.
>
> In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015-2019.

Forecasted Quantities

While forecasted quantities are included below, as noted above, the customer resource actions seek to acquire all cost-effective and reasonable customer resources, not a specific quantity. These forecasts remain the same as the 2019 IRP.

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[97] See Order 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf
[98] *Id* at 22.

- The energy efficiency forecast from the Energy Trust is for 157 MWa on a cumulative basis through 2025.
- The distributed flexibility forecast on a cumulative basis through 2025 is:
    - 141 MW winter demand response (Low: 73 MW, High: 297 MW)
    - 211 MW summer demand response (Low: 108 MW, High: 383 MW)
    - 137 MW dispatchable standby generation
    - 4 MW utility-controlled customer storage (Low: 2.2 MW, High: 11.2 MW)

J.2. Capacity and Renewable Actions

Capacity Action

Pursue dispatchable capacity through the following concurrent processes:

Action 3A. Pursue cost-competitive agreements for existing capacity in the region.

Action 3B. Conduct an RFP for non-emitting dispatchable resources that contribute to meeting PGE's capacity needs.

Renewable Action

Action 2. Conduct a Renewables Request for Proposals (RFP) seeking up to approximately 150 MWa of new RPS-eligible resources that contribute to meeting PGE's capacity needs by the end of 2024.

Conditions:

- Resources must qualify for the federal Production Tax Credit (PTC) or the federal Investment Tax Credit (ITC);
- Resources must pass the cost-containment screen;
- The value of RECs generated prior to 2030 must be returned to customers; and
- Resources must meet the transmission requirements for variable renewables described in PGE's Addendum Filing.

Portfolio Conditions

The combined capacity contribution of all procured dispatchable capacity resources (Modified Actions 3A and 3B) and all new renewable resources (Modified Action 2) will not exceed PGE's identified 2025 capacity need, currently forecasted to be 511 MW.

The combined energy additions from new non-emitting dispatchable capacity resources (Modified Action 3B) and new renewable resources (Modified Action 2) will not exceed approximately 150 MWa.

Commission Conditions

As a condition of its acknowledgment of these actions, the Commission called upon PGE to continually re-evaluate its needs in light of the pandemic's uncertain economic environment and to demonstrate through RFP design process that PGE would optimize the procurement of capacity and renewable resources whether through one or multiple solicitations.[99]

[99] See Order 20-152 at 26.

K. Sequoia Overview

Sequoia is a loss-of-load probability model that can estimate the amount of capacity needed to achieve a resource adequacy requirement[100] and to estimate resource capacity contribution values. Sequoia is a proprietary model that was developed by PGE in support of the Integrated Resource Planning process. It has an Excel User Interface, with a Python and GAMS back end and it requires a license to the Gurobi solver to achieve adequate performance. This appendix describes the main components of the model methodology and describes key model inputs and outputs.

Sequoia evaluates resource adequacy for a system by examining loads and resource capabilities over a wide range of conditions of independent weeks. This requires two modules: a Monte Carlo module to generate data for each week representing a wide range of system conditions; and a dispatch optimization module to simulate the capabilities of resources to meet load under those conditions and determine the timing and magnitude of loss of load events. Summary metrics, including loss-of-load probability, capacity need, and capacity contribution are then calculated from these results.

This overview is provided in the context of the 2019 IRP Update. PGE is working on developing additional functionality and improvements to Sequoia that will allow added sophistication in the treatment of resources and improvements in efficiency for future filings.

K.1. Monte Carlo Module

Sequoia uses a "Monte Carlo"[101] module to generate a large set of sample weeks that both maintain plausibility and capture a wide range of potential system conditions. These plausible sample weeks of load and resource conditions are used to meaningfully determine loss-of-load probability metrics. Loss-of-load standards typically require systems to eliminate lost load in all but the rarest of circumstances, often over one day or one event in several years. For example, PGE's current loss-of-load expectation requirement allows for one day (24 hours) of lost load every 10 years. Because loss-of-load events are so rare, resolving a loss-of-load expectation metric requires consideration of many more years than the period of potential events. Consideration of more years of data generally results in greater precision. While hourly load, wind, and solar data are typically only available for a limited number of years, the Monte Carlo module allows Sequoia to construct many times more plausible combinations of the data.

For the 2019 IRP Update, Reference Case capacity assessment runs through the year 2030 and the capacity contribution evaluation used 50,000 weeks per test year. To reduce model runtime,

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[100] A common resource adequacy requirement is a maximum loss-of-load expectation (LOLE).

[101] The term "Monte Carlo" is commonly used to denote stochastic analysis, which utilizes randomly generated data.

the Low and High Need assessments and Reference Case for 2031-2050 were based on 10,000 weeks per test year.

K.1.1. Day-type Characterization

One input to the Monte Carlo module is the characterization of all historical days used for load and resource profiles. Historical days are categorized by their month, weekday type (weekday or weekend), and weather conditions.[102] The days within each month and weekend/weekday bin are categorized into five equally sized weather bins according to their daily average load. These bins are used by the module to generate plausible sample weeks of potential conditions in terms of both load and resource capabilities.

The Monte Carlo simulation begins by randomly drawing seven sequential days and identifying the month, weekend/weekday, and weather day types for each day.

K.1.2. Hourly Shapes

For those loads and resources characterized by hourly shapes (such as wind and solar), for each day, Sequoia randomly draws hourly load shapes and hourly generation shapes corresponding to resources with weather and other day-type correlations from within the set of days with historical data that match the drawn day type. Within the day-type bins, random draws are independent, allowing for many different potential combinations of plausible load and resource shapes while capturing larger scale correlations via day-type binning.

K.1.3. Month-Hour Shapes

In some cases, loads or resource availability may be affected by some day-type categories, but not others. For example, a contract may have different availability based on the time of day, month of the year, and weekends versus weekdays, but not be affected by weather conditions. For these loads and resources, Sequoia draws from month-hour shapes differentiated by weekend and weekday to ensure that resource availability aligns with the day types in the seven-day period. Though not preferred, this approach can also be used as a simplifying assumption for both loads and resources for which a large set of historical hourly data may not be available. However, due to the potential for mischaracterization, this type of simplification should be avoided when possible, particularly when considering larger loads or resources.

[102] In this version of Sequoia, load is used as a proxy for weather conditions.

K.1.4. Conventional Dispatchable Resources

Sequoia simulates conventional dispatchable resource availability based on a set of operating characteristics.[103] For each simulated day, Sequoia selects the maximum capacity associated with the corresponding month. The Monte Carlo module also simulates random forced outages on each resource using a time-sequential exponential failure model. For each random forced outage, the magnitude of the outage is randomly drawn from a resource-specific partial outage distribution. This yields an hourly shape for the availability of each dispatchable resource across each generated week.

K.1.5. Hydro Resources

Sequoia simulates the availability of dispatchable hydro resources with material storage capabilities based on a set of historical hydro conditions and a randomly drawn hydro year for each generated week. The Monte Carlo simulation produces a minimum hourly output, maximum hourly output, and weekly energy constraint for each hydro resource. These constraints are based on the simulated hydro year and the month corresponding to each day of the generated week.

K.1.6. Storage Resources

Sequoia simulates the availability of energy storage resources based on charging, discharging, and storage capacity, forced outage rate, and mean time to repair. The Monte Carlo simulation simulates random forced outages on each storage resource using a time-sequential exponential failure model.

K.1.7. Hybrid Resources

Hybrid resources in Sequoia are modeled as combinations of generation resources and a linked energy storage resource. The availability of the generation and energy storage resources is determined via Monte Carlo simulation according to the methodologies described above.

K.2. Dispatch Optimization Module

Sequoia's dispatch optimization module is used to determine the capability of the resource portfolio to serve load in every hour of each simulated week. The dispatch optimization consists of a load balance equation for each hour that considers all loads in that hour and the capabilities of all resources in that hour and a set of constraints that reflects the operating constraints of the resources across the week, including contingency reserve obligations. Rather than minimizing cost or maximizing revenue, which is typically the objective of a dispatch optimization, the

[103] The monthly maximum capacity, forced outage rate, average time to repair, and partial forced outage distribution.

Sequoia dispatch optimization minimizes a linear objective function related to lost load. For this filing, the Sequoia dispatch optimization minimized the sum of the average unserved energy across the week and the maximum unserved energy experienced in a single hour during the week. This objective function helps to reduce both the occurrence of unserved energy and the magnitude of unserved energy when the system is constrained. The objective function does not consider resource cost, the resulting dispatch behavior does not reflect economic operations, but can offer insight into resource capabilities during constrained periods.

Note that Sequoia optimizes across all hours of a given week simultaneously. It is a single-stage model with perfect foresight of the week.

Resource operating constraints are applied in different ways for different types of resources depending on their dispatch type and operating parameters, as described in the following section.

Resource Operating Constraints

In the 2019 IRP Update, Sequoia uses five types of resource operating constraints. Each resource is assigned to a dispatch type that best fits the resource's operating limits. Resources within each dispatch type are aggregated in order to reduce the dispatch optimization problem size. Reducing the dispatch optimization problem size is useful for achieving runtimes that allow for the investigation of thousands of draws and the convergence of loss of load metrics. However, for some resource types, aggregation requires simplifying assumptions described below.

In this version of Sequoia, all loads and resources are modeled within a single transmission zone, consistent with the treatment in RECAP. Sequoia has some of the initial framework to consider multiple transmission zones and while that is referred to in the dispatch type descriptions below, it is not in use at this time.

Dispatch Type "C"

Dispatch Type "C" is used to simulate the dispatch of resources that can generate up to a maximum hourly value.[104] Dispatch Type "C" is often used to represent variable renewable resources, run-of-river hydro, coal, and other resources and contracts that do not have energy constraints. Dispatch Type "C" resources are aggregated within each transmission zone so that the dispatch from the fleet of Type "C" resources can be represented with a single variable for each hour and transmission zone. The aggregation consists of summing the maximum hourly capacity from each resource to determine the maximum hourly capacity of the fleet.

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[104] For resources such as wind, solar, and run-of-river hydro, the maximum hourly value is the hourly value from the profile selected by the Monte Carlo Module. It is not the maximum output capability of the resource.

Dispatch Type "Hydro"

The "Hydro" dispatch type is used to simulate dispatchable hydro resources with material storage capabilities. The fleet of hydro resources within each hydro zone is subject to weekly minimum output, maximum capacity, and energy budget constraints. Aggregation consists of summing the minimum, maximum, and energy constraints across the hydro resources in each transmission zone and hydro zone to determine the minimum, maximum, and energy constraints for the fleet specific to each transmission zone and hydro zone. This approach makes the simplifying assumption that within a transmission zone/hydro zone combination, individual hydro resources within the fleet can effectively borrow energy from each other provided that the fleet-wide energy constraint is not exceeded.

Dispatch Type "Storage"

The "Storage" dispatch type is used to simulate energy storage resources. This dispatch type employs a linear energy storage model that tracks the hourly charging level, discharging level, and stored energy based on the hourly maximum charging capacity, hourly maximum discharging capacity, maximum energy storage capacity, and roundtrip efficiency. Energy storage resources are aggregated into a single energy storage fleet for each transmission zone so that the charging, discharging, and stored energy can be represented by only three variables for each hour within the energy balance constraint. The energy storage fleet maximum charging, discharging, and storage capacities are aggregated by summing the maximum charging, discharging, and storage capacities across the storage resources in transmission zone, respectively. The energy storage fleet roundtrip efficiency is aggregated by taking a weighted average of the roundtrip efficiencies of the individual storage resources, using the maximum storage capacity of each resource as weights. This approach makes the simplifying assumption that within a transmission zone, individual resources within the fleet can effectively borrow energy from each other provided that the fleet-wide energy balance constraint is satisfied.

Dispatch Type "Hybrid"

The "Hybrid" dispatch type is used to simulate resources that combine co-located generation and energy storage. Hybrid resources in Sequoia can combine up to three generating resources with up to one energy storage resource. In addition to the resource-specific parameters (maximum hourly capacity for each generation resource and the parameters described above for any storage resources), each hybrid resource also has an associated interconnection size and flags to indicate which resources can charge the storage and whether the energy storage can be charged by the grid.[105] Dispatch constraints for the hybrid resource reflect the operating limits of the generation resources, a linear storage model, and the interconnection limit. The key parameters and the aggregation approaches applied to them are described below.

[105] As with storage resources, charging from the grid is accounted for in the load balance equation.

- The hybrid resource model leverages the same linear storage model applied to storage resources. Aggregation of the maximum charging, discharging, and storage capacities consists of summing across the maximum charging, discharging, and storage capacities of the storage resources within the hybrid resources in each transmission zone. The fleet-wide roundtrip efficiency is aggregated by taking a weighted average of the roundtrip efficiencies of the individual storage resources where the weights are equal to the maximum storage capacity of each resource. This approach makes the simplifying assumption that within a transmission zone, individual resources within the fleet can effectively borrow energy from each other provided that the fleet-wide energy balance constraint is satisfied. Some of the additional constraints described below, which further limit the energy available to the storage resources within hybrid resources, seek to reduce the impact of this simplifying assumption.

- Sequoia tracks the total maximum hourly capacity from the generation resources in each hybrid resource. Aggregation of this parameter consists of summing this maximum hourly capacity across all hybrid resources in a transmission zone to characterize the maximum capacity available from generation resources in the hybrid fleet. Note that the total maximum capacity is likely to exceed the maximum output of the hybrid resource fleet due to other hybrid resource constraints. Better alignment between the individual hybrid resource capabilities and the fleet-wide hybrid resource capabilities is achieved through additional constraints as described below, which further limit the maximum project output.

- Sequoia constrains the maximum amount of energy that can go into storage from linked resources in each hour. For individual hybrid resources, this is constrained by the charging capacity of the storage and the amount of generation available to store from linked resources. Aggregation of this parameter consists of summing this maximum storable energy across all hybrid resources in a transmission zone to characterize the maximum storable energy from generation resources in the hybrid fleet.

- Sequoia also constrains the storable energy from the grid for each hybrid resource that can charge from the grid, taking into account the interconnection limit and the portion of the storage charging capacity not available for charging from linked generating resources. Aggregation of this parameter consists of summing this maximum storable energy from the grid across all hybrid resources in a transmission zone to characterize the maximum storable energy from the grid in the hybrid fleet.

- Sequoia constrains the hourly maximum total project output based on the interconnection limit, the maximum storage discharge capacity, and the total maximum hourly capacity from the generation resources in the hybrid resource. Aggregation of this parameter consists of summing this maximum total project output across all hybrid resources in a transmission zone to characterize the maximum total output from the hybrid fleet.

Dispatch Type “G”

Dispatch Type “G” is used to simulate dispatch of resources that have a maximum hourly capacity and that may have weekly energy constraints related to fuel availability (e.g., gas plants). All resources with Dispatch Type “G” are assigned to a fuel zone and all resources within a given zone can be subject to a common energy constraint, allowing for optimization of fuel use across resources within the zone. In this IRP Update, fuel constraints are not binding. Dispatch Type “G” resources are aggregated within each transmission zone so that the dispatch from the fleet of Type “G” resources can be represented with a single variable for each hour and transmission zone. The aggregation consists of summing the maximum hourly capacity from each resource to determine the maximum hourly capacity of the fleet.

Reserves

Sequoia models contingency reserves (spinning and supplemental (non-spinning) reserves) explicitly within the dispatch optimization. The total contingency reserve obligation is determined dynamically in each hour as a function of the loads and resources and whether PGE holds the contingency reserve obligation for those loads and resources. The spinning reserve obligation is determined dynamically in each hour as half of the total contingency reserve obligation. For resources that can provide spinning and/or non-spinning reserves, Sequoia separately tracks the capacity associated with the resource that contributes to serving load, providing spin, and providing non-spin in each hour, so that the dispatch solution captures the impacts of holding contingency reserves while meeting load. Sequoia requires that contingency reserve obligations be met in each hour, so when the system is constrained, it will not release contingency reserves to avoid lost load. Instead, the dispatch simulation will identify unserved energy.

K.3. Loss-of-Load Metrics and Capacity Need

The dispatch simulations result in an unserved energy timeseries for each draw. This information can be used to determine several loss-of-load metrics, including expected unserved energy, loss-of-load probability (under several different loss-of-load event definitions); loss-of-load expectation (e.g., hours per year). In addition, the timeseries can be used to derive distributions and heatmaps describing the timing, frequency, magnitude, and duration of loss-of-load events.

For this IRP Update, the loss-of-load adequacy metric is the same as the 2019 IRP: the loss-of-load expectation (LOLE) must be no more than 2.4 hours per year.

In Sequoia, capacity need is calculated based on the number of draws, the hourly unserved energy reported for all draws, and the LOLE metric. The change in capacity need when the portfolio is evaluated with incremental resource additions is used to calculate capacity contribution values.

K.4. Baselining Exercise

PGE undertook a baselining exercise to compare the findings from Sequoia to those from the prior loss-of-load probability model, RECAP. The exercise examined the 2025 capacity need snapshot provided in the Capacity Need Assessment of the November 2019 Needs Assessment Update.

Note that throughout this section, the referenced capacity need and capacity contributions are based on information as of the November 2019 Needs Assessment Update and do not reflect the updates to the load forecast and resources that are described elsewhere in this IRP Update. Additionally, there were minor refinements to Sequoia implemented after the baselining exercise, such as the some of the hybrid resource constraints described in **Section 8.7.2.1**.

For this exercise, PGE first converted the RECAP results from the generic capacity convention to a close approximation of a perfect capacity convention by re-running the 2025 capacity need calculation in RECAP with the generic resource forced outage rate set to 0.01 percent.[106] Switching from generic capacity to perfect capacity reduced total identified capacity needs by 46 MW (approximately seven percent). This change in convention would also have a corresponding impact (reduction) to all capacity contributions: all else equal, there is no change in the amount of infrastructure required to meet a given reliability target. This change in convention would also have a corresponding impact (increase) to the net cost of capacity so that total capacity value for each resource remains unchanged.

The next step in the baselining exercise involved importing data from the RECAP case into Sequoia in a manner that preserved the resource treatments employed in RECAP. In this test, the functionality offered by Sequoia that is not available in RECAP (including dynamic dispatch of hydro resources, energy storage resources, and hybrid resources) was not activated in order to examine the impact of moving from RECAP's statistical model to Sequoia's Monte Carlo constructed weeks. This test found that switching from RECAP to Sequoia slightly increased the capacity need, in this case by 2 MW (0.3 percent), which falls within the uncertainty of the modeling approach.

The baselining exercise then tested the impacts of the new functionality offered by Sequoia, including dynamic hydro dispatch with hydro year draws, dynamic storage dispatch, dynamic treatment of contingency reserves, and dynamic hybrid resource dispatch, by layering in functionality in sequential steps, as shown in **Figure 23**. Dynamic dispatch and treatment of contingency reserves were found to reduce the identified capacity need by 52 MW, with the greatest reduction associated with the contingency reserve logic.

[106] RECAP did not solve when a forced outage rate of 0 percent was tested.

FIGURE 23. SEQUOIA BASELINING EXERCISE IMPACTS OF DISPATCH AND RESERVE LOGIC

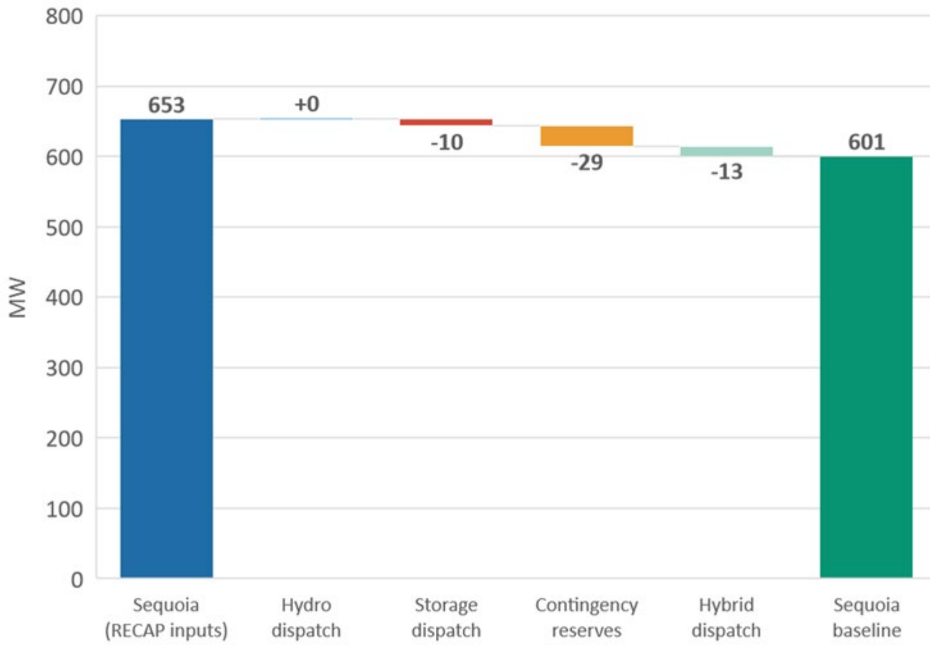
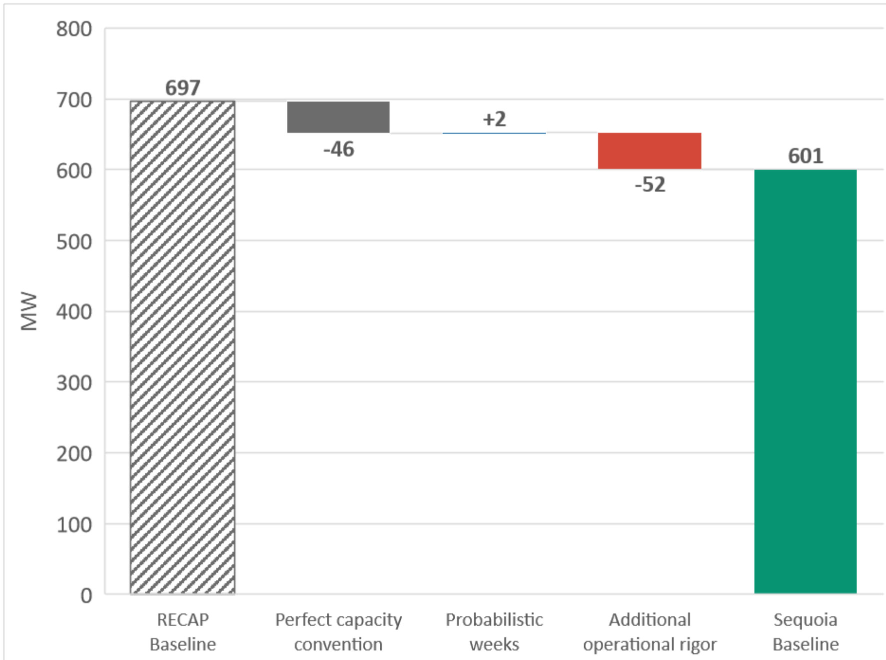


Figure 24 summarizes the findings of the baselining exercise. For this baselining case, the change from the RECAP model to the Sequoia model resulted in a reduction of the identified capacity need of 96 MW, which about half of that impact attributable to the change in convention from generic to perfect capacity and the remainder associated with the change in resource treatment within Sequoia to better capture energy-limited resource dispatch and contingency reserves.

FIGURE 24. SUMMARY OF BASELINING EXCERCISE



Despite the significant expansion of functionality with the new Sequoia methodology, the result of the baselining exercise suggest that capacity needs derived using the RECAP model in the last two IRP cycles were reasonable approximations for dispatchable energy-limited resources when compared to much more sophisticated modeling. This is reassuring, but as we work to decarbonize our portfolio and consider increasing amounts of energy-limited resources, these approximations may no longer be as reasonable. From a practical modeling perspective, the approximations also become increasingly impractical to maintain. We find that this is an appropriate time to adopt a new methodology, as our portfolio is likely to include more dispatchable energy-limited resources, such as energy storage and demand response, in the near future.