FLEXIBILITY STUDIES

Blue Marble
Analytics

Ana Mileva

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GridPath Modeling Methodology

In the 2023 IRP, PGE contracted with Blue Marble Analytics to use the GridPath power-system planning platform for the flexibility planning analysis. This analysis consists of three studies: system flexibility adequacy, the estimation of integration costs of new variable energy resources, and the assessment of candidate new resources' flexibility value. GridPath integrates production-cost simulation, used here for the flexibility analysis, in addition to capacity-expansion, asset-valuation, and resource adequacy modeling functionality within the same platform.

GridPath is open source. The codebase can be viewed on and downloaded from GitHub at https://github.com/blue-marble/gridpath. GridPath uses linear and mixed integer programming implemented in Python and the results presented here utilize the Gurobi Optimizer. Extensive documentation is available at https://gridpath.readthedocs.io/en/latest/.

For this flexibility analysis, GridPath is configured as a multi-stage optimal commitment and dispatch model. GridPath creates a constrained optimization with an objective function of minimizing total system operating costs subject to various system- and generator-level operational constraints. The enforced constraints include generator dispatch requirements and limits such as minimum up- and down-times, minimum loading levels, ramp rate limits, etc., as well as system-level hourly market availability and reserve requirements, e.g., spinning reserves, regulation, load following, etc.

We use GridPath to optimize generator dispatch and system operation for two years of interest in this IRP: 2026 and 2030. One year of analysis consists of 52 one-week model runs. For each one-week period, the model is run in three stages: Day-Ahead (DA) with an hourly timestep, Hour-Ahead (HA) with a 15-minute timestep, and Real-Time (RT) with a 15-minute timestep. The system takes in inputs in each stage and optimizes system dispatch subject to the operational constraints relevant at that stage. Commitments made in each stage (e.g., generator commitments) then carry forward to the next stage as constraints.

A summary of relevant input data updated for the 2023 IRP GridPath analysis is described in Table 1. GridPath optimizes plant dispatch and system operation under average-year conditions for inputs such as load, variable energy resource output, and hydro conditions. Load, existing contracts, variable energy resource output, and hydro conditions data are updated to forecasted average-year levels for 2026. Input gas prices, market electricity prices, and carbon prices are consistent with the 2023 IRP Reference Case. The PGE system is modeled with access to a market in GridPath; market availability limits are enforced in on-peak hours and vary by season. Market access for purchases is constrained to 100 MW in the high-load hours (HLH) in the winter, 200 MW during HLH in the spring and fall, and 0 MW in the HLH period in the summer; it is constrained to transmission limits in other time periods.

For modeling purposes in the flexibility adequacy study, an expensive day-ahead (DA) on-peak capacity product is available to the system to provide capacity. The DA on-peak capacity product is available in 100 MW increments for the 16-hour on-peak block. If selected in the DA, the DA on-peak capacity product is also available in the HA and RT stages (but cannot be decommitted). Availability of the expensive, inflexible DA on-peak capacity product allows the system to reach resource adequacy in DA when market availability is very limited in the on-peak summer and winter periods.

In the flexibility value and integration cost studies, the capacity shortage is met partially with a proxy resource portfolio that includes new wind, solar, and batteries, and partially with expensive, unconstrained purchases. In these studies, the goal is to develop a more realistic system to determine a representative estimate of the flexibility value and integration costs of new resources.

Table 1. Flexibility Studies Data Inputs

Input	Flexibility Adequacy	Flexibility Value and Integration Cost
Time frame	2026 & 2030	
Gas prices	Reference	
Carbon prices	Reference	
Electricity prices	Reference	
Load	Average year, updated to 2026 & 2030	
VER generation	Average year, updated to 2026 & 2030	
Existing contracts	Updated	
Market availability	Limited in on-peak summer and winter Unconstrained in off-peak and non-winter and summer peak	
Reserves	Regulation, contingency, and load-following reserves	
Capacity Availability	DA, HLH block capacity that is more expensive than existing system generation & markets	Proxy resources including new wind, solar, and batteries & expensive, unconstrained purchases

Flexibility Adequacy Analysis

Flexibility Metrics

To investigate the flexibility of PGE's power system, we use GridPath's production cost functionality. The GridPath flexibility analysis focuses largely on upward flexibility challenges. In designing the study, we have two key considerations:

1) While several metrics from production cost simulation exist that could indicate insufficient flexibility – for example, unserved energy or reserve shortfalls – it is important to distinguish between reliability events that can be attributed to insufficient flexibility and those due to inadequate capacity.
2) Even when not observing reliability events, our goal is to understand the underlying flexibility state of the system, i.e., how close to a flexibility-related violation the system might be.

We use two main metrics in this analysis consistent with the approach developed in the 2019 IRP Flexibility Study: unserved energy due to flexibility shortages (USE_{Flex}) and estimated system headroom. The former metric is adapted from The Flexibility Metrics and Standards Project -- a California Energy Systems for the 21st Century (CES-21) Project [1] and the latter from the Seventh Northwest Conservation and Electric Power Plan[2] and other sources.[3,4]

USE_{Flex}

The first metric we use to analyze and understand the flexibility of PGE's system is USE_{Flex}. Unserved energy is the main way in which problems due to upward flexibility challenges – either large ramps or forecast error – manifest themselves. Since we only simulate a single "average" year for hydro conditions, renewable resource output, and load, this is not a metric of "expectation" or "probability," but rather an accounting of the frequency and magnitude of these events in the modeled future year.

To decide whether the observed violations are due to insufficient flexibility or to inadequate capacity, we adapt the method used in CES-21. Whenever we observe unserved energy, we follow the decision process described in Figure 1.

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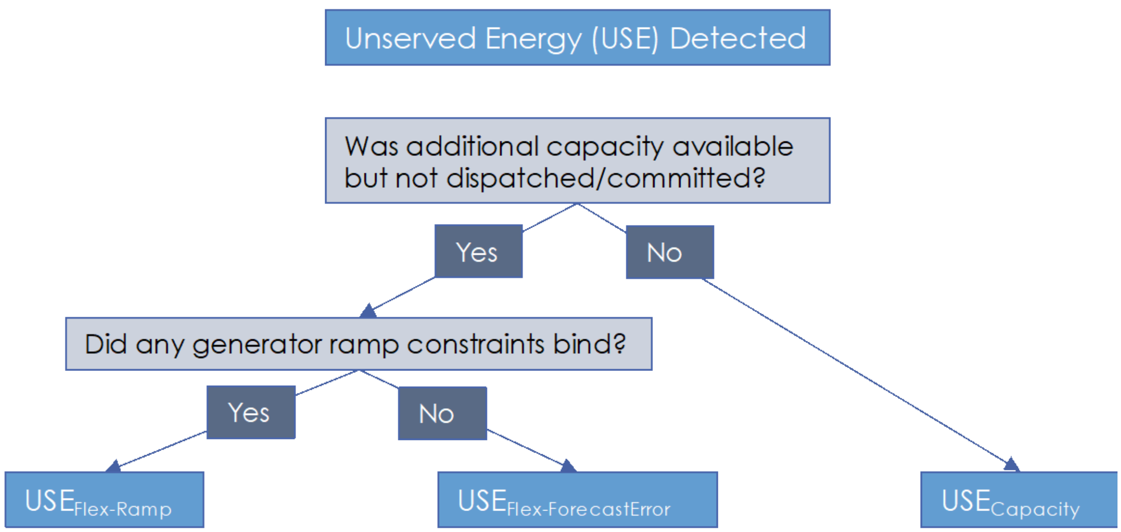
[1] Astrape Consulting, EPRI, LLNL, PG&E, and SDG&E, "Flexibility Metrics and Standards Project -- a California Energy Systems for the 21st Century (CES-21) Project," 06-Jan-2016.
[2] "Seventh Northwest Conservation and Electric Power Plan," Northwest Power and Conservation Council, Feb. 2016.
[3] "Flexibility Assessment Methods DRAFT," Bonneville Power Administration, EPRI and Northwest Power and Conservation Council, Jan. 2015.
[4] C. Anderson and J. Matevosyan, "Flexibility studies in system planning at ERCOT," in 2017 IEEE Power Energy Society General Meeting, 2017, pp. 1–5.

The first decision point is to determine whether capacity is available on the system that is not dispatched and/or committed. If not, we ascribe the reliability event to insufficient capacity and add the shortage to $USE_{Capacity}$, the unserved energy attributable to resource inadequacy, not flexibility inadequacy. If additional capacity is available during the time with unserved energy but is not running, we attribute the unserved energy to insufficient flexibility and further divide these events into two flexibility types.

The second decision point allows us to understand whether the flexibility event is caused by insufficient ramping capability or by forecast error. In the former case, capacity is available and running, but output cannot be adjusted fast enough to follow net load, manifesting itself as a binding ramp constraint; in the latter case, there are no binding ramp constraints and the reliability event occurs because of a difference between the net load forecast (usually in the day-ahead commitment stage) and the realized net load that the system is not able to adjust to, e.g., because of under-commitment of resources.

Figure 1. Decision Tree for Determining USE Type

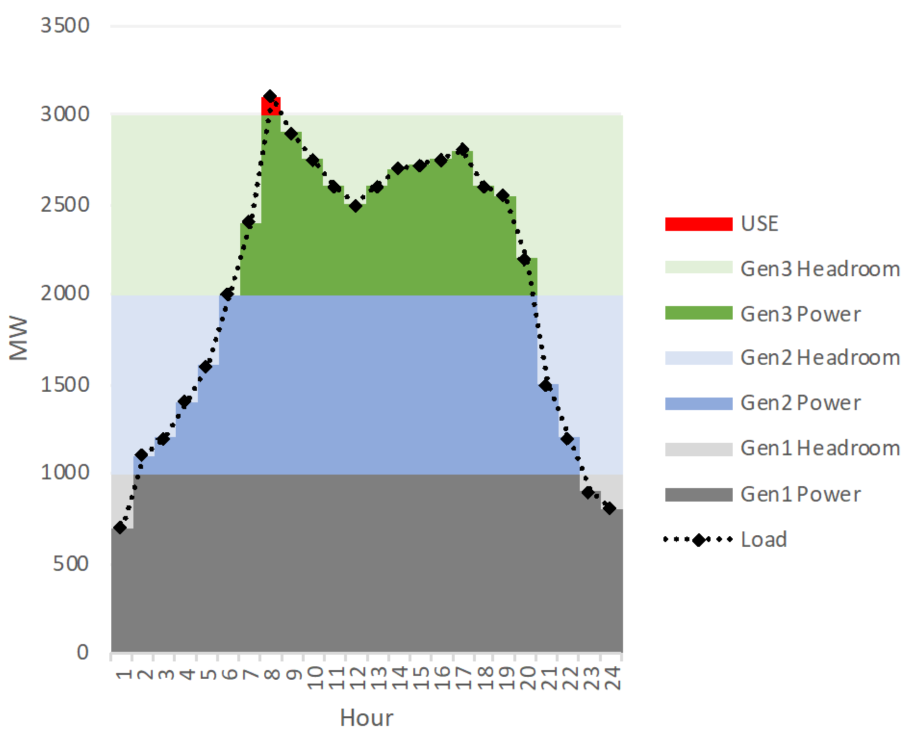


Estimated System Headroom

In addition to reliability events due to flexibility shortages, we also investigate when the system is under flexibility stress, i.e., how close the system may be to experiencing an event even when no shortages occur. In particular, we use the "system headroom" metric as an indicator of available flexibility.

System headroom is the amount of capacity available in each time period minus the capacity used up in order to meet system requirements such as load and reserves, i.e., how much additional upward capability is available to ramp up the system's resources within a certain amount of time. In the example in Figure 2, an illustrative system has three generators, each with a capacity of 1,000 MW. Initially, load is under 1,000 MW, so the first generator is serving load with some of its capacity and providing headroom with the rest; the full capacity of the other two generators can count toward the system headroom. As load goes up during the day, the amount of available headroom gradually decreases until it reaches zero: this is where the available resources are exactly equal to load. If load continues to increase beyond the point where headroom is zero, the system experiences USE. The available headroom may be further limited by a generator's ramp rate over a certain time period.

Figure 2: Net Upward Capability (Headroom) Illustrative Example



Scenarios

To explore the nature of the flexibility adequacy challenges PGE may face, we test three scenarios:

- No Flexible Additions Case, which reflects only existing resources with the capacity shortage filled with inflexible DA capacity blocks
- Renewables and Storage Case, which layers on additional renewables and storage resources
- Conservative Bookend Case, which simulates more conservative operational practices that may help address the challenges associated with net load forecast error.

Results

USE_{Flex}

In the study set-up, unserved energy is the main indicator of possible insufficient upward flexibility. We use the USE_{Flex} method described above to determine whether the unserved energy events are flexibility-related, and whether they are driven by ramping constraints or by forecast error.

In the 2026 No Flexible Additions Case, unserved energy in the real-time stage occurs 0.1 percent of the time for a total of 158 MWh over the course of the year (Table 1). All unserved energy occurs during times when the DA capacity product is not fully committed, i.e., additional resources are available on the system but are not utilized, so the unserved energy events are flexibility-related, not the result of inadequate capacity. The generator ramping and minimum up and down constraints do not bind during the times with unserved energy: the flexibility events are caused by forecast error, not insufficient ramping capability. All real-time unserved energy in the No Flexible Additions Case is therefore $USE_{Flex\text{-}ForecastError}$. The observed USE is caused by net load forecast error and under-commitment of the DA capacity product. Intra-day, however, the net load is higher than anticipated in the DA and, even after adjusting the hydro and gas generators adjust output, the system does not have sufficient recourse actions intra-day to compensate for the load forecast error during the highest net load hours and unserved energy occurs. Additional resources do exist – more DA capacity could have been committed in the DA stage – but within the day, the system is not able to adapt to the change in load conditions. The observed unserved energy is a flexibility event caused by forecast error and the inability to re-commit DA capacity within the day.

The results are similar for the 2030 No Flexible Additions Case, with the increase in load driving additional times of unserved energy occurring 0.3% of the time for a total of 501 MWh in the simulated year.

Table 2. Real Time Unserved Energy in 2026 and 2030 in the No Flexible Additions Case

	2026	2030
# 15-min Timepoints	36	112
% Timepoints	0.1%	0.3%
Total MWh	158	501
Max MW	80	122

Seasonally, the unserved energy is concentrated in the winter evening and summer net load peak hours (Table 3). In the 2026 No Flexible Additions Case, hour 19 in February experiences the most unserved energy of all month-hour segments: 3.6 percent of the time for an average of 0.8 MW short of meeting load. Unserved energy also occurs with relative frequency during the evenings in the summer: summer shortages occur most frequently in hour 22 in August and are highest on average in hour 20 in September.

Table 3. Seasonal Distribution of Unserved Energy in the 2026 No Flexible Additions Case. Top: MWa USE by Month and Hour; Bottom: USE Event Frequency by Month and Hour

HOUR ENDING

MWa USE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.1	0.0
Feb	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.8	0.1	0.0	0.0	0.0	0.0
Mar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0
Aug	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
Sep	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0
Oct	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nov	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dec	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2

% TIME WITH USE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%	1.6%	0.0%	0.0%	1.6%	0.0%
Feb	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.9%	3.6%	0.9%	0.0%	0.0%	0.9%	0.0%
Mar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Apr	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jul	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.8%	1.6%	0.0%	0.8%	0.0%
Aug	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%	0.0%	0.0%
Sep	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.8%	0.0%	0.0%	0.0%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nov	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Dec	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.8%

With additional load growth going out to 2030, the observed shortages become more frequent and increase in magnitude, and they begin occurring in the spring and fall in addition to the winter and summer seasons. The timing remains similar: the largest and most frequent shortages occur during the evening peak hours but fall and winter morning shortages also begin to appear.

Table 4. Seasonal Distribution of Unserved Energy in the 2030 No Flexible Additions Case. Top: MWa USE by Month and Hour; Bottom: USE Event Frequency by Month and Hour

HOUR ENDING

MWa USE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.1	1.8	0.2	0.0	0.0	1.8	0.1
Feb	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.8	0.1	0.1	0.0	0.3	0.0
Mar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.5	0.9	0.0	0.0
Apr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.5	0.4	0.0	0.0	0.0
Aug	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
Sep	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.9	0.0	0.0
Oct	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.2	0.0	0.0
Nov	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1	0.9	0.1	0.0	0.0
Dec	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.3	0.1	0.0	0.0	0.0	0.0

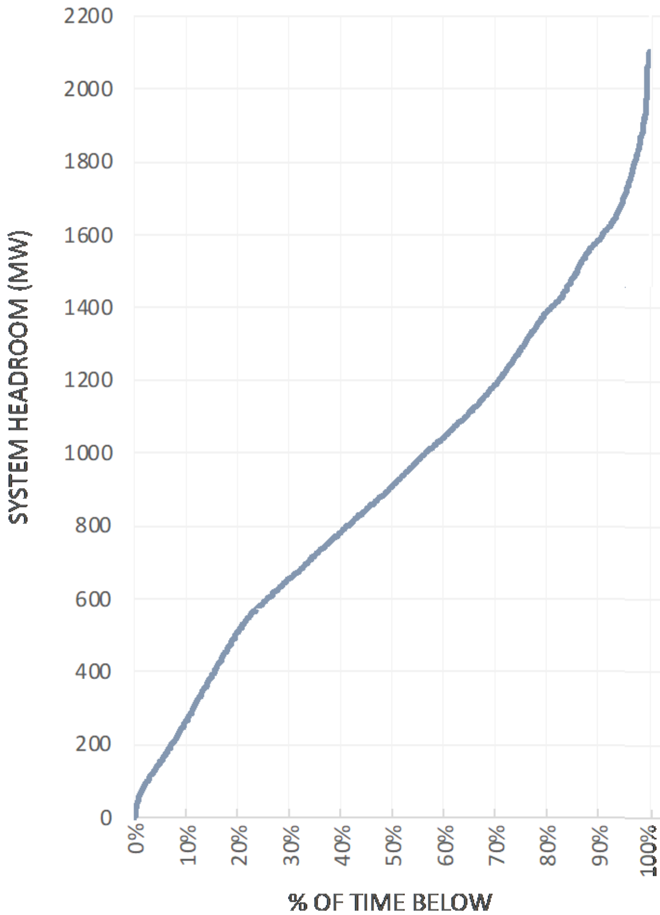
% TIME WITH USE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.8%	4.0%	0.8%	0.0%	0.8%	8.1%	0.8%
Feb	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	1.8%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.9%	3.6%	0.9%	2.7%	0.0%	1.8%	0.0%
Mar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	4.8%	2.4%	3.2%	0.8%	0.0%
Apr	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.8%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%
Jul	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	2.4%	1.6%	0.0%	0.8%	0.0%
Aug	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	0.8%	0.8%
Sep	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	2.5%	0.0%	0.0%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	4.0%	2.4%	0.0%	0.0%
Nov	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	0.0%	0.8%	1.7%	0.8%	0.0%	0.0%
Dec	0.0%	0.0%	0.8%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	3.2%	1.6%	0.0%	0.0%	0.0%	0.0%

System Headroom

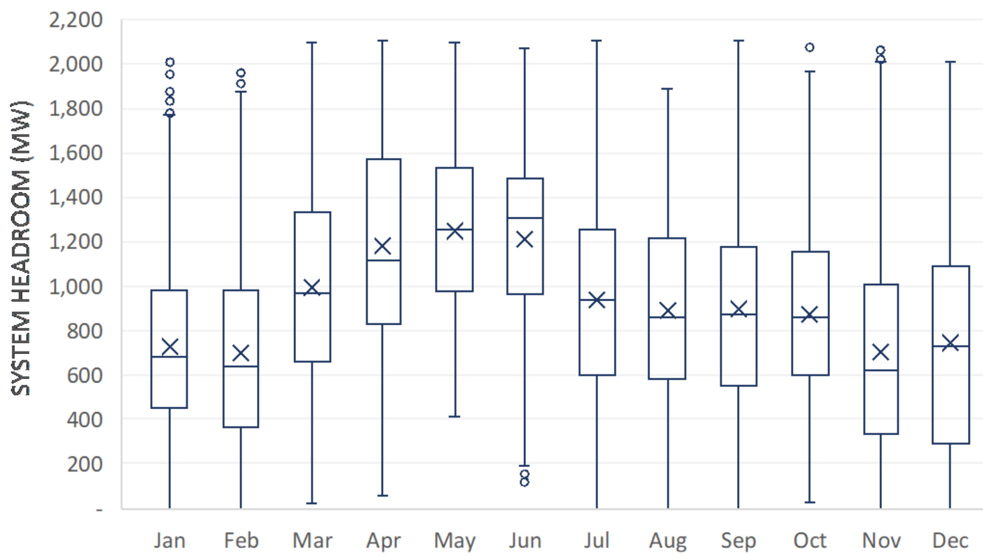
In addition to USE_{Flex}, the main metric of flexibility shortage, the underlying flexibility state of the system, i.e., how close the system may be to experiencing a flexibility-related event even if no shortages are observed, is also of interest. Figure 4 shows a duration curve of system headroom in the No Flexible Additions Case. The available system headroom can reach up to 2000 MW but is 200 MW or less 10 percent of the time, and 100 MW or less 5 percent of the time in the modeled year.

Figure 3. Duration Curve of System Headroom in the 2026 No Flexible Additions Case



On a seasonal basis (Figure 5), PGE's system is most constrained in the winter. System headroom is 300 MW or less 25 percent of the time in December and reaches zero in all three winter months as well as in November. Headroom is also frequently constrained in the summer and falls to zero in July, August, and September. System headroom is more plentiful in the spring months.

Figure 4. System Headroom Quintiles by Month in the 2026 No Flexible Additions Case



Solutions

The expensive DA capacity product used in the No Flexible Additions Case is a proxy for a highly inflexible resource that allows us to highlight the nature of the system's flexibility constraints. PGE's resource adequacy need is likely to be met with a diverse portfolio of wind and solar energy as well as storage resources to reshape that energy. To understand how flexibility adequacy may be affected by the addition of a renewables and storage resource mix instead of a highly inflexible proxy capacity product, we run a case with the resource adequacy gap met partially with a mix of wind and solar as well as storage resources: the Renewables and Storage Case. Conservative operational practices may also help to address flexibility-related problems, so we develop a proxy case for highly conservative operational practices: the Conservative Bookend Case. In this bookend case, we remove variable renewable output from the DA commitment stage but keep it available in the HA and RT stages. This forces the model to commit additional DA capacity to compensate for the lack of variable renewable output; as variable renewable production does materialize in the HA and RT stages, more total resources are now available within the day, so the system has greater flexibility to deal with forecast error.

Table 5. Real Time Unserved Energy in the Renewables and Storage Case and Conservative Bookend Case in 2026

	Renewables and Storage Case	Conservative Bookend Case
# 15-min Timepoints	5	18
% Timepoints	0.01%	0.05%
Total MWh	3	33
Max MW	6	44

Both the Renewables and Storage Case and the Conservative Bookend Case help address the flexibility challenges observed in the No Flexible Additions Case (Table 5), but more in-depth analysis is required to understand the complex interactions of resource mix, portfolio effects, operating practices, and market participation. The Renewables and Storage Case and Conservative Bookend Case do not characterize actual procurement or operating practices, nor do they consider legislative or other policy requirements. We do not attempt to make any conclusions about the relative cost of bookend conservative operations, the addition of various new resource portfolios, and other approaches for addressing flexibility violations. Rather, we seek to provide a high-level understanding of how such actions might affect flexibility-related USE and flexibility adequacy.

Conclusions

The goal of this flexibility adequacy study was to investigate whether the PGE system has adequate operational flexibility to maintain reliability as it evolves in the near- and mid-term. The results presented here indicate that if PGE fills its resource adequacy need with inflexible products, the PGE system may encounter upward flexibility challenges on the 2026 and 2030 timeframes.

In this analysis of an average-year set of conditions for 2026 and 2030 and the use of inflexible DA capacity to fill the resource adequacy shortage, forecast error is the main driver of upward flexibility shortages. The PGE system appears to have considerable ramping capability, but load and renewable forecast errors along with inflexible resource commitment timing can cause flexibility-related reliability events. High-priced contracts that provide capacity in the day-ahead are not adequate to meet the system's flexibility requirements because they are not dispatchable within the day. Such expensive day-ahead capacity contracts can create problems on days with high flexibility demand (in the form of forecast error) and procuring some level of flexible capacity and energy is necessary to address the flexibility shortages.

Addressing the capacity shortage with a diverse portfolio of wind and solar energy and batteries to reshape that energy may largely eliminate the flexibility-related problems observed, but an important caveat is that the appropriate operational practices must be in place to approximate the optimized operations modeled in this planning exercise. Storage technologies can adjust their schedules within the day as needed to respond to forecast error if sufficient energy that can be shaped is also added to the system. As the PGE system becomes less reliant on thermal generation, the associated operational constraints of commitment schedules, minimum up and down time, ramp rates, etc., will become less important; instead, ensuring energy adequacy and the availability of storage capacity dispatchable within the day may become a critical component of flexibility analysis. Conservative day-ahead commitment and market participation practices can also mitigate the flexibility challenges encountered in this analysis but suggesting realistic changes in operational practices is outside the scope of this study. In addition, we do not investigate cost impacts: we show only indicators of flexibility adequacy such as USE_{Flex} and system headroom, not relative economics.

Flexibility Value Analysis

Consistent with the 2019 IRP, the 2023 IRP estimates flexibility value, a component of PGE's economic analysis that captures the value of providing flexibility to the system by responding to forecast errors, enabling fast ramping, and meeting reserve requirements. The goal of the flexibility value analysis is to holistically account for the flexibility provided by all dispatchable resource options within portfolio analysis. Flexibility value encompasses multiple operational value streams, including load following, regulation, spin, ramping and forecast error mitigation, and renewable integration.

Flexibility values of new resources are estimated using GridPath simulations of the PGE system. For each new resource option, flexibility value is calculated by simulating the system with and without the new resources and then comparing the operational costs of the two scenarios. The resources we test are 100 MW batteries with durations between 2 and 8 hours and a round-trip efficiency of 85 percent. We also test a 10-hour pumped hydro storage resource with a round-trip efficiency of 80 percent.

PGE's estimates of flexibility values for new storage resources based on the 2026 and 2030 test years are summarized in Table 7. These values are dependent on the system that the resources are added to. The marginal value of each resource will decrease as more of it is added to the system and, beyond declining marginal benefits, the value of each resource is dependent on the resource mix of the system we are adding to. The values in Table 7 represent "mid" estimates with Reference assumptions and with the capacity adequacy shortage filled partially with a diverse resource portfolio and partially with an expensive market product

Table 6. Flexibility Value of Storage Resources (2023$/kW-year)

	2026	2030
2-hour Battery	8.35	16.71
4-hour Battery	9.77	18.75
6-hour Battery	10.68	20.65
8-hour Battery	11.78	21.38
10-hour Pumped Storage	11.47	20.86

The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (less than two hours). This finding is largely consistent with PGE's prior efforts to characterize the operational value of energy storage.

Integration Costs Analysis

PGE's IRPs have included estimates of the costs associated with the self-integration of wind generation since 2009. Consistent with previous IRPs, the 2023 IRP estimates integration costs using multi-stage commitment and dispatch modeling. We use GridPath to simulate the variable costs associated with meeting load over the course of a single year, including fuel costs, variable operations and maintenance costs, startup costs, and costs and revenues associated with market interactions.

The integration cost is calculated by dividing the system cost difference between the cases in which additional renewables are included and the respective reference case by the additional renewable output. Each resource has an energy value when added to the system in addition to a cost to integrate it. To isolate the integration cost, we compare the run with each of the test resources to one where we add 100 MWa of a resource that matches the weekly capacity factor of the test resource, but it does not have any variability within the week. The goal is to remove the difference in value that is due to the seasonal availability of the resources and focus on variability on the shorter operational timeframes.

Table 8. Integration Cost of Resource Options (2023$/MWh)

	2026	2030
Gorge wind	2.57	3.90
WA wind	2.57	3.90
MT wind	0.95	1.46
Solar	2.84	3.30
Solar + Storage (1:1)	0.33	-1.62
Geothermal	0.00	0.00
Biomass	0.00	0.00

In the 2023 IRP, we estimate renewable integration costs for 100 MWa of wind and solar resources based on a 2026 and a 2030 test year (Table 8). High production from renewable resources can result in periods of time where the system has an oversupply of renewable energy, which may be curtailed. Curtailment may occur for economic or operational reasons, and the cost and amount of curtailment depends on a variety of factors including market prices, system conditions, and resource constraints. Within the GridPath simulation of the PGE system, curtailment of renewable resources is allowed at no additional cost so that the integration costs described above incorporate any cost savings associated with dynamic renewable curtailment to provide flexibility value to the system. If renewable resources were not allowed to curtail in the simulations, we would expect the renewable integration costs to be higher than those listed in Table 6, particularly for resources that must forego the production tax credit to curtail.