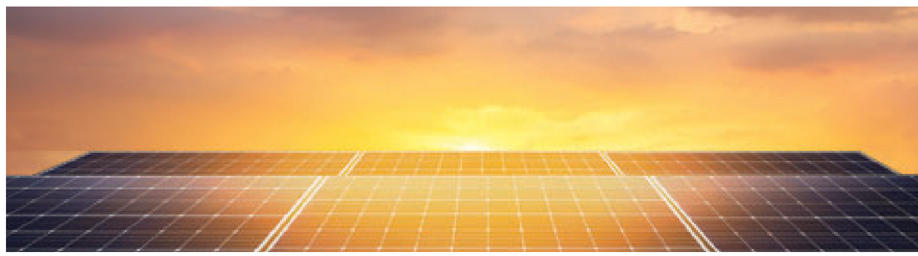
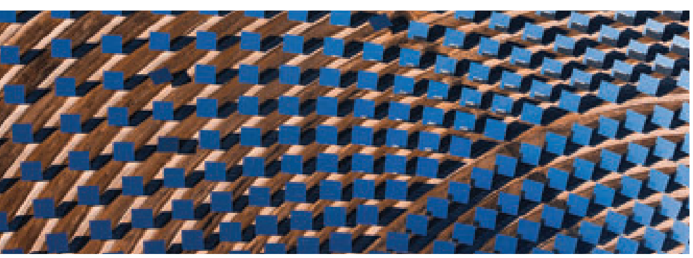
INTEGRATED RESOURCE PLAN

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2022

PACIFIC GAS AND ELECTRIC COMPANY

2022 INTEGRATED RESOURCE PLAN

NOVEMBER 1, 2022

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a. Introduction

Pacific Gas and Electric Company (PG&E) is pleased to participate in the 2022 Integrated Resource Planning (IRP) process and to contribute toward California's clean energy goals in a safe, reliable, and cost-effective manner. As one of the largest electric and natural gas energy companies in the United States, PG&E delivers some of the nation's cleanest energy to nearly 16 million people throughout a 70,000-square-mile service area in Northern and Central California.

The California Public Utilities Commission's (Commission or CPUC's) IRP Proceeding is the primary vehicle for California's electric generation planning, focused on ensuring that the electric sector is on track to reliably and affordably meet California's Greenhouse Gas (GHG) emission reductions targets. The 2022 IRP process is underway during a period of electric reliability challenges, which have been exacerbated by the effects of increasingly frequent and intense weather events. The planning paradigm is further challenged by the rapidly growing scale of needed clean energy investments, including load growth uncertainties and resource development delays due in part to supply chain problems. Despite these challenges, California is fully committed to mitigating the impacts of climate change and recently passed legislation affirming that commitment.[1] To facilitate the decarbonization of the electric sector and meet the increase in electric demand due to the electrification of other sectors that currently rely on fossil fuels, the IRP proceeding must also have a strong focus on system reliability and affordability.

PG&E's 2022 IRP is focused on meeting its IRP compliance requirements. Since the last IRP cycle, PG&E has adopted a comprehensive and ambitious climate strategy and goals[2] that guide its supply planning and portfolio optimization presented in this filing. PG&E's long term climate strategy is rooted in its triple bottom line framework of serving people, the planet, and California prosperity. PG&E has introduced ambitious emissions reduction goals that include achieving net zero GHG emissions by 2040 and being climate positive by 2050.

PG&E plans to achieve carbon neutrality through aggressive investments in GHG-free resources, including pursuing both supply and demand side solutions, with an emphasis on the role of

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[1] In 2022, California passed Assembly Bill (AB) 1279 (2021-2022 Reg. Sess.) which codifies California's 2045 carbon neutrality goal and Senate Bill (SB) 1020 (2021-2022 Reg. Sess.) which establishes interim targets toward meeting the existing SB 100 (2017-2018 Reg. Sess.) targets.

[2] PG&E's Climate Strategy Report (June 2022), <https://www.pge.com/climate> (as of Oct. 25, 2022).

breakthrough load management and emerging technologies[3]. This filing outlines PG&E's plan for decarbonizing its bundled service portfolio through 2035, while supporting reliability and affordability. To do this, PG&E forecasts needing up to 12 terawatt-hours (TWh) of additional GHG-free generation resources to be added to its portfolio by 2030. In this plan, PG&E seeks approval to begin procuring these GHG-free resources gradually over the next several years to fill this need and realize its commitment to decarbonizing its bundled service portfolio. PG&E also recognizes that its actual procurement needs may change over time as future forecasted assumptions and portfolio attributes change.

a. Key Messages

PG&E is making progress toward its climate goals. PG&E's 2022 IRP portfolio meets its climate strategy goal of 70 percent Renewable Portfolio Standard (RPS) by 2030. In fact, PG&E expects to meet or exceed its goal of 70 percent RPS by 2030 with each of its IRP portfolio alternatives, and is on a trajectory to meet its broader, net zero energy system, climate goal by 2040. In the near-term, PG&E will procure 900 megawatts (MW) of long duration storage, baseload renewables and solar plus storage consistent with the CPUC's mid-term reliability procurement order. PG&E also plans to incorporate 612 MW of demand response and 338 MW of energy efficiency and advance its demand response portfolio to 950 MW with a new automated response technology program.

PG&E requests additional procurement authorization for bringing new resources online in a timely manner. California and western markets have been facing capacity tightness as aging and inefficient powerplants in California and neighboring states retire due to market and regulatory pressures. Contracting for new clean energy resources has been challenging due to many factors, including increasing worldwide demand for GHG-free resources and ongoing raw material constraints, supply chain problems, and price volatility.

PG&E's analysis of its potential need considered four planning requirements: IRP GHG-emissions targets set by the CPUC; California's RPS compliance requirements; GHG-free energy planning targets; and monthly bundled system Resource Adequacy (RA) requirements. Based on these requirements, PG&E forecasts a potential need of up to 12 TWh[4] of additional GHG-free resources by 2030. PG&E requests Commission approval to begin procurement of GHG-free resources gradually over the next several years to satisfy this need. This request is

[3] Breakthrough load management and emerging technologies includes utilizing newer technologies (e.g., hydrogen and carbon capture, utilization, and sequestration) and includes accelerated adoption by customers of Demand Energy Response (DER) programs (PV and storage), smart technologies (EVs, smart thermostats and appliances) and efficiency measures to turn behind-the-meter and distributed resources into dispatchable resources.

[4] Equivalent to approximately 5 GW of nameplate capacity.

incremental to existing IRP procurement orders and other existing Commission mandates and equivalent to approximately five gigawatts (GW) of nameplate capacity.

Given the large amount of procurement and the electric grid system-wide reliability challenges being experienced today, PG&E would like to begin the procurement process in the near term to timely secure the procurement of the appropriate amount and type of resources. PG&E could potentially procure less than 12 TWh, for example, if load management reduces the currently forecasted need or if the expansion of Community Choice Aggregators (CCAs) or Direct Access (DA) exceeds current forecasts. PG&E will continue to monitor these drivers. This level of request meets the following objectives: 1) CPUC's 2030 GHG targets for PG&E, 2) 70 percent RPS in 2030, and 3) places us on a trajectory for 90 percent GHG-free in 2035 as well as the CPUC's 2035 GHG target.

PG&E's 2022 IRP Action Plan, outlined in Section IV, is consistent with PG&E's 2030 climate strategy and goals, which emphasize expansion of RPS resources, promoting storage, and facilitating customer action to mitigate climate change through home and vehicle electrification and expansion of load management.

PG&E supports the use of the higher load forecast for planning that includes ambitious vehicle electrification. To address climate change, the electric sector will play a central role in decarbonizing the transportation sector. This is reflected in California's new rules on zero-emission vehicle sales. California needs to plan for an electrified transportation sector today. With this in mind, PG&E believes the CPUC should adopt a higher transportation electrification load forecast scenario for planning. PG&E's climate strategy is aligned with the underlying assumption of increased transportation electrification and higher GHG emission reductions, and the 2022 IRP's Additional Transportation Electrification (ATE) scenario aligns closest with its internal load forecast for the post-2030 horizon. This is an important assumption for resource planning to achieve California's climate and reliability goals.

There is a risk that the new resources required to address GHG reduction goals and support reliability will not be online in a timely manner. The CPUC Preferred System Plan adds over 40 GW of incremental new nameplate capacity by 2030 and over 50 GW of incremental new nameplate capacity by 2035. This level of new resource additions is unprecedented and will require significant effort and coordination among state agencies to bring the new capacity online in time to meet California's decarbonization goals. In addition, the ongoing supply chain issues, competition from other states/nations/industries for lithium batteries and interconnection issues will continue to pose challenges for bringing new resources online. The state will need to proactively address regulatory hurdles and assess alternatives to avoid the impact of delays.

More work needed for IRP to assure reliability. Although the CPUC's IRP portfolios meet the 0.1 Loss of load Expectation (LOLE)[5] planning standard, this does not guarantee that the system will provide sufficient energy in extreme weather hours, such as the peak loads seen in summer 2020 (47 GW) and 2022 (52 GW). More work is needed to ensure that the effects of climate change and factors to mitigate their impact is included in the IRP reliability assessment. In addition, local and zonal resource need assessment continues to be a gap in the current IRP process that needs to be immediately addressed. To address these gaps, PG&E has offered recommendations for improved reliability planning in the Lessons Learned section.

PG&E supports expanded load management solutions in future plans. As we work to diversify and optimize its portfolio to support California's decarbonization goals, PG&E believes that Distributed Energy Resources (DERs) and load management, broadly, will play an increasingly important role. In fact, PG&E thinks an increased emphasis in advanced load management is necessary to achieve California's GHG reduction goals. Therefore, PG&E would like to see a greater focus on load management solutions in future plans.

The current IRP does not fully consider DERs, including behind-the-meter (BTM) resources as explicit resources to be optimized within the portfolio. Instead, the Commission reduces demand by energy produced (or saved) for demand side resource programs (e.g., BTM PV, storage, energy efficiency, electrification) to calculate a retail sales load that needs to be served by bulk supply resources.

Moreover, the IRP does not include what PG&E has called "breakthrough" load management (e.g., emerging programs such as vehicle-to-grid) options to meet system demand. The Commission recently issued a new rulemaking[6] to, among other issues, better integrate DER progress into the IRP process. The emergence of technology to turn BTM and distributed resources into dispatchable resources creates an opportunity to optimize load and supply and ensures the most affordable mix of resources. PG&E supports this initiative and offers more discussion below on the advanced load management and demand-side programs that should be central to California's clean energy environment.

b. PG&E's Climate Strategy Guides the 2022 IRP

While adhering to the direction provided in the CPUC's IRP proceedings and rulings, PG&E's 2022 IRP reflects progress toward its climate commitments of achieving a net zero energy system five years ahead of California's 2045 carbon neutrality deadline and to achieve a

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[5] 0.1 LOLE is an industry standard reliability metric. 0.1 LOLE means a chance of one loss of load day every ten years.

[6] See Order Instituting Rulemaking to Develop Policy and Create A Consistent Regulatory Framework for Distributed Energy Resource Customer Programs, Track 1 Scope, pp. 34-35, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K223/488223301.PDF> (as of Oct. 25, 2022).

climate- and nature-positive energy system by 2050. To date, PG&E has made significant progress transitioning the grid to renewable and environmentally friendly supply of resources and beginning the transportation and building electrification process. However, in order to ensure reliability and affordability as the state increases the pace of electrification and work toward integrating intermittent renewable generation, optimizing the grid will require a more diverse mix of resources including advanced load management and emerging technologies. PG&E's 2022 IRP is guided by the following key climate strategies.

i. Diversify Using Conventional and Emerging Technology

A diversified and optimized energy system will rely on a combination of traditional GHG-free energy sources (e.g., utility scale solar, wind, geothermal), emerging technologies (e.g., offshore wind (OSW)), and will provide opportunity for PG&E's customers to participate in the clean energy future by leveraging existing and emerging load management solutions (e.g., real-time pricing, vehicle-to-grid programs). Leveraging a diverse mix of resources will be necessary to meet its ambitious decarbonization goals and will help to build climate resilience within PG&E's service area.

ii. Advanced Load Management & Demand-Side Programs

California's electricity use is anticipated to increase significantly over the next 20 years, after decades of relatively flat demand, due to transportation and building electrification. To reliably and affordably serve PG&E's bundled customers while also decarbonizing the California economy, PG&E plans to pursue a diverse portfolio which includes advanced load management solutions as an alternative to traditional power generation. Some load management examples include leveraging dynamic pricing, DERs that respond to dynamic grid conditions, advanced rate design, and emerging technologies such as bidirectional chargers to help customers take an active role in reducing our collective carbon footprint while lowering their energy bills. In addition to helping meet PG&E's goal of reducing direct operational and indirect carbon emissions by 50 percent by 2030, demand-side solutions help its customers take an active role in reducing their own carbon footprint and lowering their own energy bills by aligning usage with lower cost and lower-emitting electricity.

iii. Unleash Electric Vehicle Potential

PG&E is an industry leader in facilitating the electrification of the transportation sector. This is evidenced by the nearly 400,000 operational electric vehicles (EVs) being served by us in its service territory. Transportation electrification is the next frontier of decarbonization in California: currently the transportation sector accounts for 40 percent of California GHG emissions. Although EVs represent a planning challenge for us due to increased demand on the grid, PG&E views EVs as a source of opportunity for us to address reliability and customer resilience as part of the advanced load management programs described above.

PG&E's 2030 goal is to realize a cumulative reduction of more than 58 MMT of carbon emissions with at least 3 million EVs in its service territory. To do this, PG&E will prepare the grid for 12,000 GWh of EV charging and make grid investments to help bring to fruition California's new policies of 100 percent sales of light-duty Zero-Emission Vehicles (ZEV) by 2035, 100 percent med- and heavy-duty ZEVs in operation by 2045, and 100 percent off-road ZEVs and equipment in operation by 2035. PG&E has prepared an alternative portfolio utilizing the Inter-Agency Working Group (IAWG) ATE load forecast which is most closely aligned with this climate strategy goal. Select results from that portfolio are presented in its 2022 IRP through Section III: Study Results.

iv. Affordability and Equity

PG&E recognizes that achieving California's ambitious climate goals affordably requires selecting the most cost-effective mix of resources. Affordability is important not just because of the impact of high energy costs on PG&E's customers, but also because lack of affordability threatens the success of building and transportation electrification efforts that are necessary for California to meet its carbon reduction goals. As noted previously, meeting our collective environmental goals will require a diverse mix of resources including emerging technology and advanced load management. Meeting these goals cost-effectively will require understanding the optimal balance of resources through improved IRP modeling tools to assess DER solutions, which is discussed in more length in Sections I.b and V.

Beyond affordability, PG&E is also committed to equity. PG&E is committed to promoting customer incentives that do not unduly shift costs to other customers and rate design that ensures all customers pay equitably for the service they receive. Advanced load management strategies must be thoughtfully designed to provide opportunities for participating customers to reduce overall household energy costs, provide customer resiliency, and provide customers the opportunity to reduce emissions without unfairly burdening non-participating customers with higher costs.

With a longer-term goal of a climate and nature-positive energy system, PG&E is committed to reducing its own carbon footprint and helping to enable its customers to reduce their climate impacts. PG&E developed its climate strategy in pursuit of its bold vision to take action to address climate change. These key climate strategies help guide PG&E's action plans and serve as a roadmap for its goal to actively remove more GHG than PG&E emits by the year 2050. To that end, these climate strategies also guide its 2022 IRP filing.

c. Study Design

PG&E developed two (2) Conforming Portfolios and one (1) Additional High Electrification portfolios for its IRP:

- 30 MMT Conforming (38 MMT by 2030 | 30 MMT by 2035)
- 25 MMT Conforming (30 MMT by 2030 | 25 MMT by 2035)
- 30 MMT + 2021 Integrated Energy Policy Report (IEPR) ATE Alternative Portfolio

PG&E's 2022 IRP modeling effort was guided by two key modeling principles: (1) Adhere to CPUC IRP guidelines; and (2) Provide planning insights in meeting study objectives. PG&E used a three-step process described in Section II to develop an optimized bundled portfolio for the scenarios considered by PG&E. This process allowed PG&E's portfolios to be tested against the following four requirements:

1) GHG emission planning benchmark established by CPUC
2) California's RPS (Renewable Portfolio Standard) targets
3) California's GHG-free (Greenhouse Gas) energy target
4) PG&E's system capacity needs to meet RA requirements

Each of the conforming scenarios were tested against PG&E's RPS compliance requirements, the IRP's LSE GHG benchmark (measured using the Clean System Power (CSP) Tool), a trajectory for achieving California's energy and climate goals promulgated by SB 100, and other key bundled portfolio requirements, such as system RA needs, to determine the need for any incremental additional resources and the best technological fit for any such incremental additional resource need.

The state has directed PG&E to pursue all necessary activities to extend the operations of the Diablo Canyon Power Plant (DCPP) through 2030; however, under applicable law, SB 846, the Commission as well as all LSEs are prohibited from including the energy, capacity, or any attribute from the DCPP in the IRP process and in each LSE's individual integrated resource plan portfolios beyond the current DCPP retirement dates[7]. Therefore, PG&E's 2022 IRP does not account for any energy, capacity, or other attributes from the DCPP for the period after the current retirement date for DCPP. This approach is consistent with the Commission's 2021 Preferred System Plan (PSP).

In addition, in order to address the requirements for LSEs within PG&E's service territory to include in their IRP filings a description of its plans addressing the retirement of DCPP and the characteristics of its energy output, including flexible baseload and/or firm low-emission energy,[8] PG&E's procurement forecast presented in its 2022 IRP accounts for the retirement of DCPP, by its current retirement date, and the amount and types of procurements forecasted in the plan are inclusive of the energy, capacity, and other attributes that will need to be satisfied through other resources upon the retirement of DCPP.

PG&E's 2022 IRP procurement forecast is inclusive of the zero-emission resources ordered by the Commission as part of the Mid-Term Reliability (2023-2026) procurement decision, which

[7] The assumed retirement dates for DCPP Unit 1 and Unit 2 are consistent with the expiration of current operating licenses. These dates are November 2, 2024 for Unit 1 and August 26, 2025 for Unit 2.

[8] D.19-04-040, p. 179, OP 12.

included, among other things, a procurement mandate for all LSEs to address the retirement of DCPP by procuring 2,500 MW[9] of incremental zero emission capacity resources.

Accordingly, PG&E's 2022 IRP accounts for the retirement of DCPP under current retirement dates, does not include DCPP or any of its attributes for the period after its current retirement date, and includes replacement resources necessary to replace the supply provided by DCPP upon its retirement.

d. Study Results

PG&E's bundled portfolio results demonstrate compliance with the four requirements listed above. To meet these requirements, bundled portfolio results show a need to procure additional resources. Additional resources will be needed by 2030 for PG&E to meet its GHG emissions planning targets and to stay on a trajectory to meet California's GHG-free energy requirements[10] while addressing increasing electrification demand. Among the scenarios analyzed, the 30 MMT + 2021 IEPR ATE Alternative Portfolio best aligns with PG&E's climate strategy and commitment of 3 million EVs by 2030 as well as the California Air Resources Board's (CARB) electric sector GHG emissions target.

In its plan, PG&E is requesting to procure GHG-free resources gradually over the next several years to fill up to an approximately 12 TWh GHG-free energy need (~5 GW nameplate) in 2030 and reduce its 2030 GHG emissions by 3.3 MMT to meet PG&E's GHG emission target. With this new proposed procurement, PG&E's plan demonstrates that it meets its reliability and RPS requirements for 2030, and positions PG&E for meeting the GHG-free energy requirements adopted in SB 100. Beyond 2030, PG&E's plan also identifies the incremental resources that would be needed to achieve the projected 2035 requirements and a trajectory for meeting PG&E's climate strategy commitment for a net zero energy system by 2040. Overall, PG&E's IRP portfolio results are driving PG&E's IRP procurement strategy for meeting its 2030 requirements while allowing more time for transportation electrification and demand-side solutions to develop before procuring additional resources for meeting post-2030 requirements.

e. Action Plan

The Action Plan described in Section IV demonstrates PG&E's activities alignment with its planning and procurement strategy, outlines current and planned activities to address DAC, and notes what actions PG&E requests for the Commission to consider supporting the effective

[9] D.21-06-035, p. 96, OP 6, "to ensure that the capacity retiring at the Diablo Canyon Power Plant is replaced entirely with zero-emitting resources, all load-serving entities shall collectively procure a minimum of 2,500 megawatts (MW) of incremental zero-emissions capacity".

[10] Initially adopted in SB 100 for 2045. Updated by SB 1020, signed by the Governor on September 16, 2022, which established interim targets for 2035 and 2040.

implementation of its plans. PG&E's 2022 IRP Action Plan is highly influenced by PG&E's climate strategy and the plan is on track to meet California's GHG emissions targets. Each subsection of the action plan provides a clear overview of PG&E's progress toward achieving its GHG target compliance and offers valuable contributions to meeting California's clean energy goals in a safe, reliable, and cost-effective manner.

PG&E has a wide array of programs available to customers residing in DACs. These programs have evolved over the years, and now include other programs that offer greater access to clean technologies that help minimize criteria air pollutants both inside customer homes and in the broader community. PG&E anticipates that there will continue to be more programs developed to help address and mitigate poor air quality in DACs, particularly programs that have a direct impact on air quality, such as expanding access to EVs and building electrification.

Based on PG&E's analysis, PG&E determined its forecasted need to be up to 12 TWh (~5 GW nameplate) in 2030. PG&E requests authority from the CPUC to begin procuring additional resources to fill this need and to stay on a trajectory to meet California's GHG-free requirements adopted in SB 100 for 2045 and in SB 1020 for 2035 and 2040. More detail on PG&E's procurement authorization request can be found in Section IV.c of this 2022 IRP filing.

f. Lessons Learned

While in the middle of this cycle's filing process, the CPUC recognized the need to design a new programmatic approach to procurement to determine more efficient and longer-term contracting procurement requirements for reliable and clean resources. PG&E applauds the CPUC for examining a fundamental overhaul in this process. PG&E is pleased to participate in this separate process and believes that it is an appropriate forum for it and other LSEs to bring up suggested changes for consideration by the Commission. Many of the lessons learned from this year's IRP cycle already seem to be teed up in the Reliable and Clean Power Procurement Program Staff Options Paper.

In the Lesson Learned section, PG&E has included recommendations in the following areas for further improvement or greater collaboration in future IRP proceedings:

1) Enhancement of the Commission's capacity expansion modeling capabilities;
2) Improvement in Commission's reliability assessment efforts to adequately address climate change impact and location specific resource requirements[11];
3) Improvement in key IRP modeling assumptions; and
4) Enhancement of IRP modeling capabilities and coordination between the CPUC, California Energy Commission (CEC), and California Independent System Operator (CAISO) for integrated resource planning that incorporates load management solutions in the development of cost-effective portfolios.

[11] Location specific requirements driven by transmission limitations.

More detailed information and context for each of these points stated above can be found in Section V. Lessons Learned.

II. Study Design

In this section PG&E describes how it developed its 2022 IRP filing, including the:

- Objectives for the analytical work presented in the filing and scenarios included in PG&E's Plan; and
- Description of the study methodology including tools and approaches used in developing PG&E's scenario analysis.

a. Objectives

PG&E's key objectives for its IRP align with the customer-focused mission that drives all its activities: to safely and reliably deliver affordable and clean energy to its customers and communities every single day, while building the energy network of tomorrow. PG&E's IRP analysis specifically focuses on the following key objectives:

- **Clean energy:** For decades PG&E has been a leader in developing clean energy technologies in California. In 2021, PG&E delivered nearly 48 percent of its electricity from RPS-eligible renewable resources, such as solar, wind, geothermal, biomass, and small hydropower. Additionally, PG&E's GHG-free energy production, which includes renewable resources, large hydropower, and nuclear energy generation, satisfied 91 percent of PG&E's bundled retail sales in 2021.[12] Among other important goals, PG&E's IRP analysis is focused on facilitating a path for PG&E to meet its clean energy requirements under SB 100 as well as its 2030 and 2035 GHG planning benchmarks assigned in this IRP.
- **Reliability:** Maintaining reliability is critical, both for the overall electric system and local segments of the system, especially as California transitions towards higher shares of GHG-free generation resources, many of which are intermittent resources.
- **Affordability:** PG&E's IRP analysis selects resources to meet the state's clean energy and reliability goals in a least-cost manner to customers. PG&E provides a system average rate forecast in compliance with the CPUC's requirements for IOUs.

[12] PG&E, Renewable Energy and Storage, <https://www.pgecorp.com/corp_responsibility/reports/2022/pf03_renewable_energy_storage.html> (as of Oct. 25, 2022).

PG&E developed three IRP scenarios[13] to address PG&E's proportional share of a GHG targets set by the CPUC consisting of two conforming load scenarios and an alternative load scenario:

- Scenario 1: 30 MMT GHG, Conforming Load
- Scenario 2: 25 MMT GHG, Conforming Load
- Scenario 3: 30 MMT GHG, Additional Transportation Electrification (ATE) Load

PG&E has included only two conforming load scenarios to meet all of the requirements set forth in the narrative templates as required by the CPUC, one for the 30 MMT GHG emissions target (Scenario 1) and one for the 25 MMT target (Scenario 2). PG&E also includes the results for the additional load scenario (Scenario 3) since this scenario includes additional transportation electrification load forecast that best aligns with PG&E's climate strategy and commitment of 3 million EVs by 2030 as well as CARB's electric sector GHG emissions target. The IRP scenarios developed by PG&E are summarized in Table 1 below.

TABLE 1
PG&E'S IRP SCENARIOS

Line No	Value	30 MMT Conforming	25 MMT Conforming	30 MMT ATE Alternative
1	PG&E Net System Sales (2030)	77,800 GWh	77,800 GWh	83,379 GWh
2	PG&E Bundled Sales (2030)	28,020 GWh	28,020 GWh	30,029 GWh
3	PG&E GHG Emissions Benchmark (2030)	3.998 MMT	3.013 MMT	3.998 MMT
4	PG&E Net System Sales (2035)	81,536 GWh	81,536 GWh	99,425 GWh
5	PG&E Bundled Sales (2035)	29,852 GWh	29,852 GWh	36,401 GWh
6	PG&E GHG Emissions Benchmark (2035)	3.086 MMT	2.466 MMT	3.086 MMT

A. Scenario 1: 30 MMT GHG, Conforming Load

Objective: Meet the filing requirements established by the Commission.

CPUC Scenario Assumptions:

[13] Consistent with the CPUC 2022 IRP filing requirement, "[e]ach LSE must produce and submit at least two "Conforming Portfolios:" one that achieves emissions that are equal to or less than the LSE's proportional share of the 38 MMT by 2030 and 30 MMT by 2035 GHG targets (the 30 MMT conforming portfolio), and another that achieves emissions that are equal to or less than the LSE's proportional share of a 30 MMT by 2030 and 25 MMT by 2035 GHG targets (the 25 MMT conforming portfolio)." 2022 Narrative Template (June 15, 2022), p. 4, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials> (as of Oct. 25, 2022).

1) 2021 Integrated Energy Policy Report (IEPR) Mid Case loads utilized per CPUC Filing Requirements; and
2) 38 MMT GHG target by 2030 & 30 MMT GHG target by 2035; CSP Calculator Tool based on 30 MMT Conforming portfolio.

For the 30 MMT Conforming Scenario, PG&E developed its portfolio based on CEC's 2021 IEPR load forecast as outlined in the June 15, 2022, Administrative Law Judge (ALJ) Ruling.[14] PG&E's bundled load is 28,020 GWh in 2030 and 29,852 GWh in 2035 in this scenario.

For the 30 MMT Conforming Scenario, PG&E's assumptions are consistent with CPUC's Updated 2021 PSP with the following exception:

- For future procurement of mandated program resources not yet in PG&E's bundled electric portfolio,[15] PG&E used its internal cost estimates derived from program and PG&E commercial data for calculating the revenue requirements.

B. Scenario 2: 25 MMT GHG, Conforming Load

Objective: Meet the filing requirements established by the Commission.

CPUC Scenario Assumptions:

1) 2021 IEPR loads utilized per CPUC Filing Requirements; and
2) 30 MMT 2030 GHG & 25 MMT 2035 GHG targets; CSP Calculator Tool based on 25 MMT Conforming portfolio.

For the 25 MMT Conforming Scenario, PG&E's assumptions and methodologies were consistent with its approach in developing the 30 MMT Conforming Scenario, albeit using the CSP model provided by the Commission for the 25 MMT case. PG&E's bundled load is unchanged (28,020 GWh in 2030 and 29,852 GWh in 2035) in this scenario.

C. Scenario 3: 30 MMT GHG, ATE Load

Objective: Quantify impact on portfolio of adopting a higher EV load forecast, a key uncertainty in the 2021 IEPR Mid case forecast.

CPUC Scenario Assumptions:

1) IAWG ATE load forecast
2) All other assumptions in the 30 MMT ATE Alternative Scenario are consistent with the 30 MMT Conforming scenario.

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[14] *ALJ's Ruling Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for the 2022 Integrated Resource Plan Filings* (June 15, 2022) ("June 15, 2022, ALJ Ruling"), R.20-05-003.

[15] Includes ReMAT and BioMAT mandated RPS procurement programs. PG&E ReMAT Feed-In Tariff, <https://pge.accionpower.com/_pgeremat/home.asp> (as of Oct. 10, 2022) and PG&E BioMAT Feed-in Tariff, <https://pgebiomat.accionpower.com/_pgebiomat/home.asp> (as of Oct. 25, 2022).

b. Methodology

i. Modeling Tool(s)

PG&E has employed several analytic tools in developing its resource plans and in forecasting costs used in the revenue requirement and average bundled rate calculations. The tools fall into two broad categories:

1) CAISO System Tools: used to ascertain the resource buildout and underlying market attributes at the CAISO system level; and
2) Bundled Portfolio Analysis Tools: used to model PG&E's bundled portfolio.

The two sets of tools are linked, as outputs from the CAISO System Tools (e.g., CAISO resource mix) are used as inputs into the Bundled Portfolio Tools. A high-level description of the modeling tools used in the analysis follows below.

A. CAISO System Tools

1) **CPUC's RESOLVE Model:** PG&E relied solely on the RESOLVE capacity expansion results (e.g., system-level resource portfolios) because the commitment and dispatch modeling and the time granularity in RESOLVE are highly simplified. PG&E used its own proprietary models, as described below, that take the RESOLVE capacity expansion results as inputs to develop market price forecasts that are needed for the bundled portfolio assessment.
2) **PG&E's Hourly Power Price Forecast Tool:**[16] This model establishes CAISO hourly power prices as a function of the CAISO system net-load and dispatchable resources available at each hour. Key inputs for this model are the CAISO system-level resource mix forecast, CAISO load and net import levels, all of which come from the specified RESOLVE model run. The model also relies on natural gas prices and GHG prices from the June 2020 CEC gas commodity mid-case forecast. The June 2020 CEC forecast was used by the CPUC in development of the Updated 2021 PSP that informs PG&E's IRP. The hourly prices are used to calculate the bundled portfolio generation revenue requirements. The hourly prices are also essential inputs to other commodity forecast models (namely, RA and REC price forecasts) required for the generation revenue requirement calculations.
3) **PG&E's Capacity Price Forecast Tool:**[17] This tool uses a weighting methodology applied to current and historical capacity transactions, market price quotes, and published forecasts. The methodology aggregates and profiles prices for existing

[16] Note that this model is PG&E's proprietary model and is used routinely by PG&E as part of its forward curve development process, and variants have been used in past regulatory filings, including in ERRA forecast proceedings.

[17] This is a PG&E-proprietary model.

transaction maturities and extends pricing beyond current maturities according to historical trend.

4) **PG&E's REC Price Forecast Tool:**[18] The REC price forecast tool calculates REC forward price by calculating a per-MWh premium for RPS-eligible energy. For example, the REC forward price for a given year, say 2024, for a solar resource is calculated based on the levelized cost of a new solar resource coming online in 2024, minus the levelized market revenue of the new solar resource. The tool also incorporates prices of recent REC transactions in the short term.

B. Bundled Portfolio Analysis Tools

1) **CPUC's CSP Model:** The CSP model is used to quantify PG&E's GHG emissions and local air pollutants associated with serving its bundled load on an hourly basis for PG&E's IRP scenarios. PG&E used the two versions of the CSP model that were provided by the Commission to analyze its Bundled Portfolio under the 30 MMT and 25 MMT Cases for both the Conforming cases and the ATE load forecast case. For the ATE case, PG&E modified the load inputs based on the data provided in the Additional Transportation Load Electrification forecast produced by the IAWG. PG&E also leveraged the hourly load energy shapes for calculating the bundled portfolio generation revenue requirements.
2) **PG&E's Procurement Portfolio Planner (P^3):** This proprietary model developed by PG&E forecasts PG&E's electric portfolio generation and procurement costs.[19] P^3 includes the electric portfolio's individual contracts and dispatchable unit characteristics. Market prices and bundled load are exogenous inputs to the model. The model follows an economic dispatch protocol where in each hour the dispatchable units are dispatched against the forecast hourly price. The generation and cost outputs from P^3 serve as the primary inputs into PG&E's bundled generation revenue requirement model.
3) **PG&E's Bundled Portfolio Optimization Tool (BPOT):** This proprietary tool determines the optimal mix of new generation and storage resources to be added to the bundled electric portfolio under scenarios where the existing set of resources is unable to meet certain operational and/or policy constraints. The model uses linear programming to select a mix of new assets from a set of candidate resources thereby yielding the lowest overall portfolio costs. The model is set up to minimize the net present value of portfolio costs (new resource costs plus spot market transactions) over the forecast horizon subject to meeting the following four portfolio constraints.

[18] This is a PG&E-proprietary model.

[19] PG&E has used the P^3 model in a variety of regulatory proceedings including ERRA Forecasts used to set rates.

(i) IRP-mandated 2030 and 2035 LSE GHG planning targets

The model is designed to meet the 2030 and 2035 GHG emission targets based on the GHG emission methodology utilized in the CSP model. The primary input assumption for determining a candidate resource's GHG emission impact on PG&E's portfolio is the marginal hourly GHG emission impact assumption derived from the 30 MMT and 25 MMT CSP models. Figures 1 and 2 show the hourly average GHG emission reduction impact by season associated with incremental GHG-free generation for the 30 MMT and 25 MMT CSP models. Candidate resources that generate in hours and seasons with higher emissions reductions impacts will be valued higher under this methodology whereas resources with higher generation in hours of low emissions factors would provide less value. For example, the incremental GHG emission reduction impact from an additional MWh of solar generation is less compared to other candidate resources because there are more midday, peak solar generating hours that provide no emission reduction benefit compared to other hours.

FIGURE 1
HOURLY AVERAGE SEASONAL MARGINAL GHG EMISSIONS FACTOR (30 MMT BY 2035)

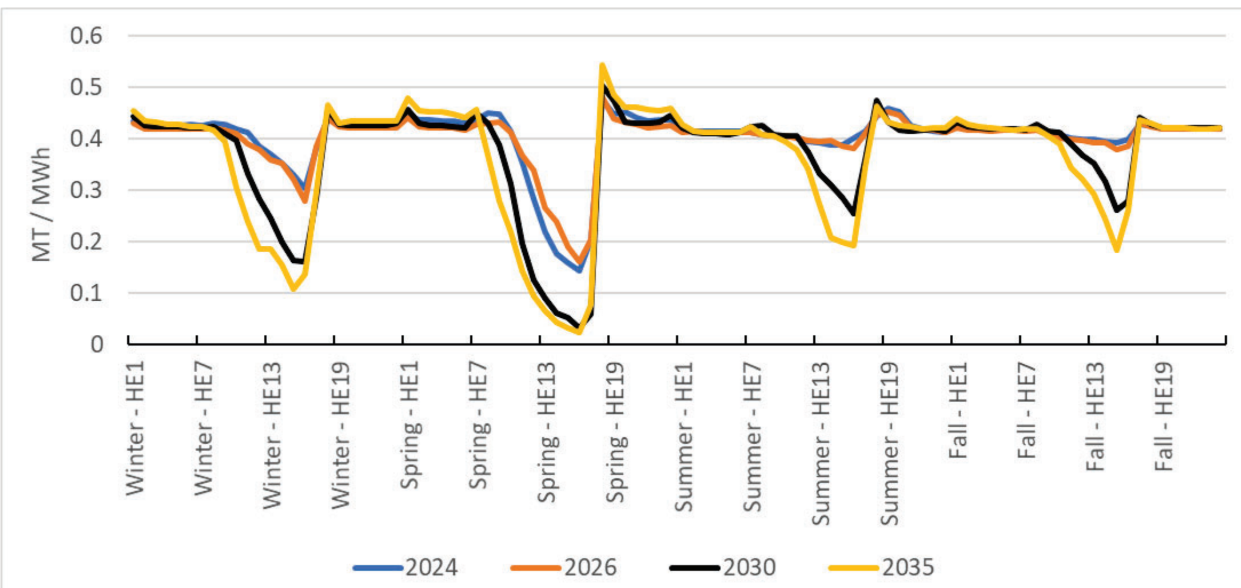
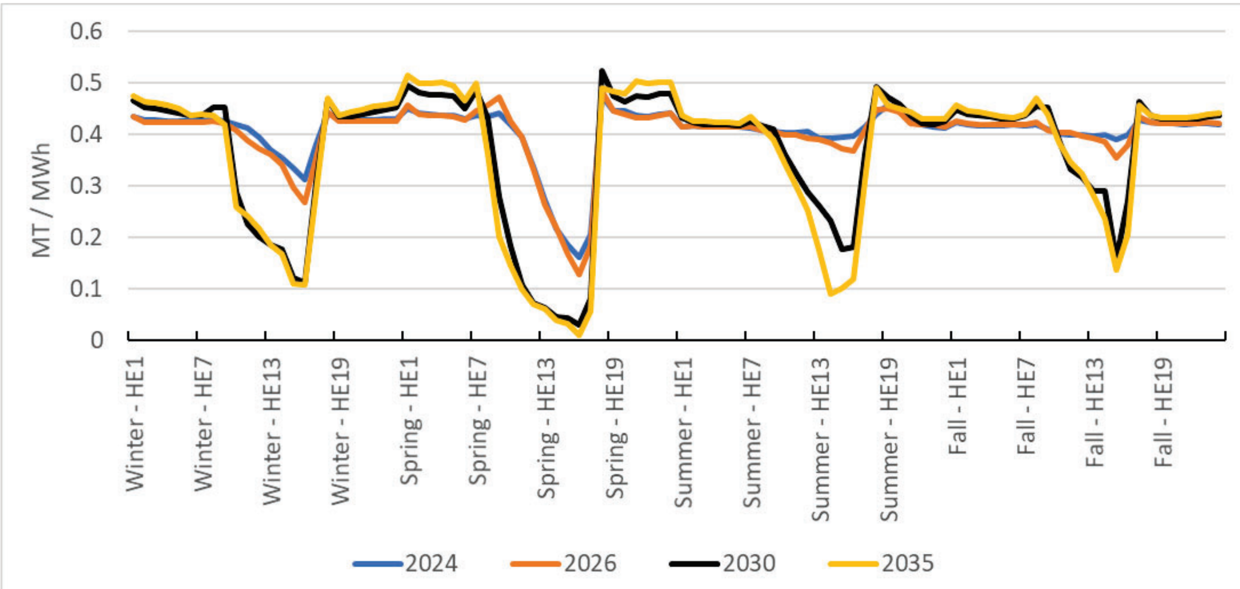


FIGURE 2
HOURLY AVERAGE SEASONAL MARGINAL GHG EMISSIONS FACTOR (25 MMT BY 2035)



The marginal hourly GHG emission impact rates are calculated based on adjusted System Power emission intensities from the 30 MMT and 25 MMT CSP models. The adjustments account for CSP model hours where there is non-displaceable system power, which results in the modeled system GHG emissions being allocated to all LSEs on a pro rata basis. Since additional GHG-free energy supply in these hours has no impact on an LSE's GHG emissions, PG&E adjusts the System Power emission intensity to zero in such hours when determining a candidate resource's impact on PG&E's total GHG emissions.

(ii) <u>California's annual RPS requirements</u>

PG&E uses the adopted annual RPS requirement targets based on the 44 percent, 52 percent, and 60 percent RPS requirements for 2024, 2027 and 2030, respectively. After 2030, the RPS requirement is held at 60 percent while the supply content constraint transitions to a GHG-free requirement trajectory.

(iii) Estimated annual GHG-free[20] requirements based on SB 100

Given the 100 percent GHG-free energy requirement by 2045 adopted in SB 100[21], PG&E developed an annual GHG-free requirement constraint to develop portfolios that position PG&E to meet the 2045 requirement with more linear, consistent annual procurement rates.

(iv) Estimated monthly bundled System RA open position

To ensure PG&E's IRP portfolio is meeting the System RA requirements required by the IRP filing requirements and Public Utilities Code Section 454.52(a)(1)(E) , PG&E sets monthly open position targets for each year of the IRP modeling horizon. These targets are based on estimated bundled peak load requirements and system RA supply from PG&E's bundled electric portfolio prior to any potential resource additions from future IRP procurement orders.

The model utilized the levelized cost of energy (LCOE) for resources from the 2021 PSP Update RESOLVE datasets and all related assumptions including inflation rate, levelization period, discount rate, taxes, and financing. (See Appendix 1: Bundled Portfolio Optimization Tool for a more detailed description).

4) **PG&E's RPS and GHG-free Stochastic Model:** PG&E's forecasted bundled RPS and GHG-free energy positions are determined using PG&E's RPS and GHG-free energy stochastic model. PG&E utilizes this model for RPS position planning in the RPS Plan proceeding, most recently in PG&E's draft 2022 RPS Plan.[22] The model accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to support position planning within designated levels of non-compliance risks.
5) **PG&E's Bundled System RA Model:** PG&E utilizes a structured query language (SQL) system RA model to determine the net qualifying capacity forecasts of its electric portfolio and the projected monthly net open positions.[23]

[20] GHG-free energy refers to the eligible renewable energy resources and zero-carbon resources referred to in California's SB 100 supply requirements.

[21] Constraints do not match the SB 1020 interim 2035 and 2040 GHG-free targets given the bill was approved on September 16, 2022.

[22] PG&E's Draft 2022 Renewable Energy Procurement Plan (July 1, 2022), R.18-07-003, <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=709459> (as of Oct. 25, 2022).

[23] 2022 IRP modeling based on existing system RA planning requirements while the RA Reform 'slice-of-day' methodology adopted in D.21-07-014 is developed for implementation in 2025.

6) **PG&E's Bundled Generation Revenue Requirement Model:** PG&E utilizes a SQL-based revenue requirement model for calculating gross and net bundled generation revenue requirement costs by established generation cost recovery types. Cost recovery types include categories such as Energy Resource Recovery Account (ERRA), Power Charge Indifference Adjustment (PCIA), Cost Allocation Mechanism (CAM), etc. with net cost calculations consistent with established methodologies and PG&E's commodity prices assumptions.

ii. Modeling Approach

This section describes PG&E's modeling approach for its Bundled Portfolio.

A. Overview

PG&E's 2022 IRP modeling effort is guided by two key modeling principles:

- Adhere to CPUC IRP guidelines; and
- Provide planning insights in meeting study objectives.

PG&E followed these guiding principles to select the most appropriate tools, approaches, and assumptions for this IRP filing.

PG&E used a three-step process described in this section to develop an optimized bundled portfolio for the scenarios considered by PG&E. This process allows PG&E's portfolios to be tested against the following four requirements:

1) GHG emission planning benchmark established by CPUC
2) California's RPS (Renewable Portfolio Standard) targets
3) California's GHG-free (Greenhouse Gas) energy target
4) PG&E's system capacity needs to meet RA requirements

The three-steps in PG&E's portfolio development process are:

<u>Step 1: Establish Assumptions to Be Used in the Analysis</u>

For each scenario, the first step is to establish assumptions for PG&E bundled and CAISO system loads and market prices to be used in the different scenarios. These assumptions, along with assumptions for CAISO system level resource mix, are required to determine whether PG&E's portfolio meets the desired requirements listed above and to calculate PG&E's bundled portfolio revenue requirements. Certain assumptions have been specified by the Commission as part of the filing requirements.

Step 2: Determine Incremental LSE Resource Needs

Once the assumptions for the analysis have been established, the next step is to test if PG&E's existing and planned portfolio of bundled resources[24] will meet the three portfolio requirements and determine PG&E's incremental resource need.

Step 3: As Necessary, Acquire Least-Cost New Resources

If Step 2 above shows a need for additional resources—for instance, to meet the GHG planning benchmark—then an additional step is taken to determine the optimal portfolio to fulfill such need. Functionally, this step resembles the capacity expansion process performed by Energy Division staff and E3 to establish the PSP for the CAISO system, but this step is employed for PG&E's bundled customers only.

B. Modeling Process Details

This section includes a more detailed description of the modeling processes underlying the three-step approach described above. It also provides additional discussion on the reasons behind specific modeling approaches.

Step 1: Establish Assumptions to Be Used in the Analysis

There are multiple sub-steps to develop assumptions to be used in subsequent steps and to calculate the rate forecast:

a) *Establish Bundled Load Forecast* – As discussed in the previous section, for the Conforming Scenarios, PG&E used the CPUC's prescribed load forecast for PG&E bundled customers.

b) *Establish Price Inputs* – Price inputs are used for developing hourly energy, REC, and RA prices. PG&E aligned price assumptions with 2021 PSP Update assumptions or assumptions from the CEC 2021 IEPR.

   1) Natural Gas and GHG Allowances – To develop the hourly energy prices for the Conforming Scenarios, PG&E used the 2020 IEPR Update natural gas and GHG price forecasts.
   2) Technology Cost – For developing REC prices, PG&E used LCOE forecasts for different technologies from the CPUC's PSP RESOLVE model.

c) *Develop CAISO System Portfolio* – For PG&E's Conforming Scenarios, this is simply the CPUC's PSP.

d) *Develop Energy Prices* – Since RESOLVE does not provide 8,760 hourly market energy prices, PG&E's Hourly Power Price Forecast Tool was used to develop hourly energy prices required to perform revenue requirement and rate calculations. Inputs to this

[24] Includes utility-owned resources, resources with existing contracts, and resources to be added to meet mandates.

model include CAISO load, the CAISO system portfolio, and natural gas and GHG prices. These hourly energy prices are integral to calculating the bundled portfolio generation revenue requirement for energy market sales or purchases. They are also an essential input to other commodity forecast models required for producing the capacity and REC price forecasts discussed below.

e) *Develop Capacity Prices* – PG&E developed capacity price forecasts using PG&E's Capacity Price Forecast Tool. This tool, as described above, estimates capacity prices based upon directly observed historical and current capacity transactions. As such, the Capacity Price Forecast Tool does not use Energy pricing directly in its methodology, so capacity price forecasts are agnostic to PG&E's scenario-specific energy price forecasts.

f) *Develop REC Prices* – REC prices are calculated as the difference between the levelized technology cost paid to acquire a new resource and the resource's estimated market revenue. Consequently, technology cost and market revenue are the largest determinants of the forecasted REC prices. For PG&E's Conforming Scenarios, REC prices were derived using the technology costs from RESOLVE and revenues based on Conforming Scenario prices.

Step 2: Determine Incremental LSE Resource Needs

For PG&E's Conforming Scenarios, PG&E modeled its bundled supply portfolio based on its latest data on existing contracts, future procurement for existing mandated programs, and planned power purchase agreement (PPA) expirations (e.g., CHP) and utility-owned generation (UOG) (e.g., DCPP) resource retirements to determine PG&E's additional resource need, if any.[25]

For all scenarios, PG&E included procurement under various CPUC-mandated programs, including energy storage resources for which it has sought approval pursuant to both Resolution (Res.) E-4909 and the 2019 IRP and 2021 IRP Procurement Track mandates.

PG&E then tested the bundled supply portfolio against established requirements (e.g., RPS, GHG, and RA) to determine if there was any incremental resource need.

a) *GHG Emissions:* PG&E's GHG emissions and need for incremental resources were calculated using the CPUC-provided CSP model.

b) *RPS Requirement:* PG&E's bundled supply portfolio was tested to identify if additional renewables are needed to meet RPS compliance requirements.

c) *RA Requirement:* PG&E's system RA requirements and need for incremental resources were calculated using both the CPUC-provided RDT RA calculator and PG&E's Bundled System RA model.

[25] For IRP planning purposes, PG&E assumes no re-contracting with expiring CHP facilities. This is an IRP planning assumption only.

Step 3: If Necessary, Acquire Least-Cost New Resources

A bundled portfolio optimization step is triggered if Step 2 identifies a need for additional resources to meet PG&E's GHG planning benchmark or RPS requirements. For its 2022 IRP, all three of PG&E's portfolios required PG&E to perform the optimization step.

C. Revenue Requirement and Rates Modeling

PG&E developed its revenue requirement and System Average Bundled Rates (SABR) for the Conforming Scenarios utilizing the 2021 IEPR Mid sales forecast or the ATE sales forecast, consistent with the 2022 IRP narrative requirements published on June 15, 2022. Only generation varied by scenario. Serving the higher load in the ATE forecast could require additional distribution and transmission infrastructure which has not been quantified in this report. The baseline revenue requirement forecast includes the following components:

Distribution (D)

- The Distribution revenue requirement forecast includes all approved and pending revenue requirement applications. Forecast years 2023 through 2026 reflect PG&E's pending 2023 General Rate Case (GRC), as updated September 6, 2022. Subsequent years escalate the prior year's base revenue requirement using an escalation factor of approximately 4 percent, which is based on the growth of the authorized GRC distribution revenue requirement in the 2017 GRC and 2020 GRC. In addition to the GRC base revenue requirement, the distribution revenue requirement reflects incremental revenue requirements for EV infrastructure, Alternative-Fuel Vehicle, Catastrophic Event Memorandum Account (2023), Wildfire Mitigation and Catastrophic Events Memorandum Account (2023-2024), Emergency Reliability, CPUC Fee, Family Electric Rate Assistance program, Mobile Home Park investments, and Hazardous Substance Mechanism.

Transmission (T)

- The transmission revenue requirement includes the currently effective Transmission Owner (TO) base revenue requirement for 2022 and forecasted TO20 Rate Year 2023 revenue requirement for the year 2023. Beyond 2023, the TO revenue requirement escalates by approximately 7 percent per year which is based on historical trends. In addition, the adjustments for the Federal Regulatory Energy Commission (FERC)-jurisdictional balancing accounts are also included in the transmission revenue requirement: (1) Reliability Services Balancing Account (RSBA), (2) Transmission Revenue Balancing Account (TRBA), (3) Transmission Access Charge Balancing Account (TACBA), and (4) Transmission Energy Cost Recovery Amount.

Demand-Side Management (DSM) Programs

- The DSM Programs' revenue requirements forecast includes all approved and pending revenue requirement applications. The is includes revenue requirements associated with Demand Response (DR), Energy Efficiency (EE), and DSM Programs.

Generation (G)

- PG&E's bundled customer generation revenue requirement is comprised of the expected bundled customer share of the forecasted cost recovery mechanisms for supply resources and the forecasted bundled portfolio costs recorded in ERRA. The supply resource cost recovery mechanisms include the CAM, Ongoing Competition Transition Charge (CTC), PCIA, Tree Mortality Non-bypassable Charge (TMNBC), and BioMAT. ERRA costs are primarily comprised of energy and related product purchases from the CAISO, retained RA and REC purchases from CTC, PCIA, and BioMAT generation resources, RPS sales revenues, and residual RA transactions. RA, REC, and CAISO market energy price assumptions are consistent with the PSPs described above. Further details regarding each revenue requirement can be found in PG&E's 2023 ERRA Forecast application.[26]
- As specified in the IRP filing requirements, the generation revenue requirement also includes the forecasted bundled customer share of electric distribution utility (EDU) carbon allowance auction revenues as an offset to the forecasted generation procurement costs. PG&E's forecast of these revenues are based on carbon prices from the 2021 IEPR mid demand scenario and PG&E's specified annual allowance allocations in California's Code of Regulations available through 2030[27], and post-2030 allocations based on PG&E's estimate of future allowance allocations.

Other

- The revenue requirements forecast for the "Other" category includes all approved and pending revenue requirement applications. This category includes: (1) the Public Purpose Programs, excluding those considered EE, DR, DSM, TMNBC, or BioMAT, (2) Wildfire Fund Charge, (3) Nuclear Decommissioning, (4) Energy Cost Recovery Amount, (5) Wildfire Hardening Charge, (6) Recovery Bond Charge and Recovery Bond Credit.

The non-generation revenue requirement forecast, comprised of Distribution, Transmission, DSM Programs, and Other is paired with the 2021 IEPR scenario's load forecast to derive the

[26] See A.22-05-029.

[27] See Cal. Code Regs. Tit. 17, § 95892, Table 9-4.

System Average Delivery Rate (SADR).[28] The SADR includes all non-Generation rate components and thus applies to all system sales independent of customers' choice of PG&E or third-party supplier. The remaining costs are reflected in the Generation/Commodity revenue requirement and rate, which include the scenario-specific planning assumptions for market price forecasts and for market sales or purchases.

For the generation costs of the Conforming Scenarios, PG&E relied on the Commission's planning assumptions to develop price assumptions used for market purchases or sales. The Conforming Scenarios use PCIA revenue forecasts that assume market-based valuation of the portfolio's attributes, which reduces cost shifts to bundled customers.

The SABR was determined using a two-step process. First, the sum of the revenue requirements for all non-generation rate components applicable to all customers was divided by PG&E's forecasted total system sales for the respective year to determine the SADR. Second, the forecasted bundled share of generation revenue requirements was divided by PG&E bundled sales to determine bundled customers' Generation Rate.[29] The SADR and the Generation rate are summed to determine the SABR.

D. GHG Emissions and Local Air Pollutants

PG&E relied on the CSP Calculator to model GHG emissions and local air pollutants from its bundled portfolio. In accordance with the LSE GHG benchmarks published on June 28, 2022, PG&E's LSE-specific 2030 and 2035 GHG emissions benchmarks are 3.988 MMT and 3.086 MMT for the 30 MMT scenario and 3.013 MMT and 2.466 MMT for the 25 MMT scenario.[30]

The CPUC's CSP calculator is also used to determine the emissions levels of three criteria pollutants for PG&E over the planning horizon. The pollutants included in the tool are $PM_{2.5}$, SO_x, and NO_x. Though no formal requirement was mandated by the CPUC, the emissions levels of each of these pollutants from PG&E's portfolio are provided in the Study Results section of this filing.

E. System Reliability

PG&E relied on both the RDT system reliability calculator and its Bundled System RA model to calculate and assess the net system RA positions for its bundled portfolio.

During the development of PG&E's RDT for this filing, PG&E identified an area for improvement in the process. While it is important that individual LSEs demonstrate compliance with existing

[28] SADR does not include non-bypassable charges recovered through CTC, PCIA, or CAM rates, to which a majority of customers in PG&E's service territory are subject.

[29] Forecasted bundled share based on the bundled sales percent of the applicable total sales for each cost recovery mechanism.

[30] See June 15, 2022, ALJ Ruling.

RA requirements, simply demonstrating compliance with existing RA requirements may not be sufficient to assure system reliability. PG&E therefore encourages that the Commission determine whether new or different metrics should be used for assessing system and local reliability given the current resource mix. For more details, refer to the "Planning for Reliability" portion of Section V: Lessons Learned.

III. Study Results

Overall, PG&E expects that it will need to procure new incremental resources beyond its current mandated procurement in order to meet the IRP GHG emission targets in 2030 and 2035 as well as achieve an annual GHG-free energy requirement trajectory that positions PG&E for achieving California's GHG-free energy requirements adopted in SB 100. For IRP planning purposes, PG&E has identified an incremental need for 10 to 12 TWh (3 to 5 GW nameplate) of new resource additions by 2030 and 15 to 22 TWh (6 to 11 GW nameplate) by 2035 across the three portfolios that were evaluated and as is shown in Tables 7 through 9.

In the following subsections, PG&E presents the following results for the three portfolios created to meet the requirements for the three scenarios: (1) 30 and 25 MMT GHG, Conforming Load Portfolios and 30 MMT GHG, ATE Load Portfolio; (2) GHG Emissions; (3) Local Air Pollutants and DACs, (4) Cost and Rate Analysis, (5) System Reliability Analysis; (6) High Electrification Planning; (7) Existing Resource Planning; (8) Hydro Generation Risk Management, and (9) Resource Development.

a. Conforming and Alternative Portfolios

PG&E prepared two Conforming and one Alternative Portfolios:

1) Conforming Portfolio for Scenario 1: 30 MMT GHG, Conforming Load; and
2) Conforming Portfolio for Scenario 2: 25 MMT GHG, Conforming Load.
3) Alternative Portfolio for Scenario 3: 30 MMT GHG, ATE Load.

This section includes results of PG&E's analysis to confirm that its two Conforming and Alternative ATE Portfolios meet its GHG emission, RPS, and RA requirements. This section also includes details of PG&E's baseline portfolio of resources (Tables 4 and 5), which includes the additional resources PG&E plans to bring online in the future to meet the procurement mandates that the Commission already authorized for PG&E (Table 6), as well as additional candidate resources that PG&E might add to meet each of the portfolios' compliance with GHG emissions, RPS, and RA compliance requirements (Tables 7 through 9).

i. Energy Sales Forecast

Pursuant to Commission guidance, the Conforming portfolios use the published 2021 IEPR Mid load forecast and the ATE portfolio uses the ATE 2021 IEPR load forecast[31] produced jointly by the CEC, CPUC and CAISO. The ATE forecast was developed in order to examine the impact higher electrification scenarios may have on the transmission system. It also best aligns with PG&E's climate strategy and commitment of achieving 3 million EVs by 2030 as well as CARB's

[31] Additional Transportation Electrification Scenario 2021 – Hourly Projections – CAISO, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-IEPR-03> (as of Oct. 25, 2022).

electric sector GHG emissions target. Tables 2 and 3 show the composition of PG&E's bundled retail sales forecast assumption for the Conforming and ATE portfolios, respectively.

PG&E Unmodified Bundled Customer Demand represents PG&E's bundled sales forecast prior to adjusting for EE, DG, EVs, and electrification. PG&E's Bundled Sales represent PG&E's sales forecast after accounting for these load modifiers. PG&E Net System sales represent PG&E's total service territory sales after accounting for DA (including BART) and CCA load.

For the Conforming portfolios, Table 2 shows that expected increases in EE and DG photovoltaic (PV) mostly offset the sales increase driven by electrification demand (e.g., EVs) such that the average annual growth rate in PG&E Bundled Sales is approximately one percent from 2024 to 2035. The ATE Alternative portfolio in Table 3 shows an average annual growth rate in PG&E Bundled Sales closer to 3 percent over the same period driven by EV growth that is approximately 5,800 gigawatt-hours (GWh) greater in 2035 compared to the Conforming portfolio.

TABLE 2
CONFORMING PORTFOLIOS ENERGY SALES FORECAST (GWH)

Line No.	Description	2024	2026	2030	2035
1	**PG&E Unmodified Bundled Customer Demand**	31,980	32,514	33,684	35,885
	Bundled Load Modifiers				
2	Energy Efficiency	(414)	(720)	(1,280)	(1,942)
3	Solar PV	(4,240)	(4,867)	(6,226)	(8,006)
4	Non-PV	(1,658)	(1,626)	(1,569)	(1,535)
5	BTM Storage Losses	8	13	23	36
6	**Total Distribution Generation**	(5,890)	(6,480)	(7,772)	(9,504)
7	EVs	1,059	1,514	2,385	3,792
8	Building Electrification	120	219	439	756
9	Other Electrification	243	352	563	865
10	**PG&E Bundled Sales**	**27,098**	**27,399**	**28,020**	**29,852**
11	**Metered PG&E Service Area Demand**				
12	DA	11,393	11,393	11,393	11,393
13	CCA	36,583	37,024	38,387	40,292
14	PG&E Net System Sales	75,074	75,816	77,800	81,536

(a) Totals may not add due to rounding.

(b) Forecasted Bundled, DA, and CCA demand from the LSE energy load forecast assigned pursuant to the June 15, 2022, ALJ Ruling. https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=485625915.

(c) Lines 5, 7-9 have been modified from the 'Demand Inputs' tab of the Conforming CSP model to reflect demand at the customer meter.

(d) Line 4 reflects PG&E's Bundled Share of 'Other Private Generation' from the 'IEPR CAISO Load Modifiers' tab of the CSP model. This generation source is not reflected in subsequent results tables.

TABLE 3
ATE PORTFOLIOS ENERGY SALES FORECAST (GWH)

Line No.	Description	2024	2026	2030	2035
1	**PG&E Unmodified Bundled Customer Demand**	32,995	33,555	34,739	36,929
	Bundled Load Modifiers				
2	Energy Efficiency	(415)	(722)	(1,286)	(1,963)
3	Solar PV	(4,535)	(5,159)	(6,517)	(8,292)
4	Non-PV	(1,658)	(1,626)	(1,569)	(1,535)
5	BTM Storage Losses	8	13	24	36
6	**Total Distribution Generation**	(6,185)	(6,771)	(8,063)	(9,790)
7	EVs	843	1,335	3,635	9,595
8	Building Electrification	120	219	441	765
9	Other Electrification	243	352	563	865
10	**PG&E Bundled Sales**	**27,602**	**27,968**	**30,029**	**36,401**
11	**Metered PG&E Service Area Demand**				
12	DA	11,605	11,630	12,210	13,893
13	CCA	37,264	37,793	41,140	49,131
14	PG&E Net System Sales	76,471	77,390	83,379	99,425

(a) Totals may not add due to rounding.

(b) Forecasted Bundled, DA and CCA demand is scaled up from the CPUC's LSE energy load forecast assigned per June 15, 2022, ALJ Ruling https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=485625915 for PG&E's ATE scenario.

(c) Lines 5, 7-9 have been modified from the 'Demand Inputs' tab of the Conforming CSP model to reflect demand at the customer meter under a high electrification scenario.

ii. Resource Portfolio

PG&E's electric portfolio is comprised of baseline resources that have already begun deliveries or are expected to come online by 2030, as shown in Table 6, or future resource additions needed to meet the IRP's GHG emission planning requirements, as well as clean energy and system RA requirements, shown in Tables 7 through 9 for each of the identified portfolios. The total gross capacity of PG&E's baseline generating resources is shown in Table 4 and represent the total contract or utility-owned asset equivalent capacity by technology type.

TABLE 4
GROSS CAPACITY OF BASELINE PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Resource	2024	2026	2030	2035
1	Solar	4,513	5,220	5,229	4,312
2	Large Hydro	2,403	2,403	2,403	2,363
3	Nuclear	1,118	0	0	0
4	Wind	948	845	704	479
5	Out of State Wind	540	450	450	0
6	Storage				
7	Battery Storage – LSE	3,046	4,191	4,322	4,152
8	Battery Storage – CPE	3	95	95	95
9	Pumped Storage	1,212	1,212	1,212	1,212
10	Small Hydro	436	435	395	326
11	Biomass	287	269	234	158
12	Geothermal	22	72	222	200
13	Biogas	48	66	84	63
14	Natural Gas				
15	Natural Gas – LSE	2,294	1,967	1,569	1,569
16	Natural Gas – CPE	1,910	8,170	7,600	7,600
17	Total Gross Capacity	18,780	25,394	24,517	22,528

By 2030 PG&E expects its baseline portfolio mix to change in the following three ways: (1) no nuclear capacity as a result of the retirement of DCPP[32]; (2) LSE contracts with natural gas-fired generators forecasted to be replaced with Central Procurement Entity (CPE) contracts with non-utility owned natural gas-fired generators located in local capacity areas within PG&E's service territory[33]; and (3) growth in battery storage capacity as PG&E continues to transition to a clean, reliable supply portfolio while meeting CPUC procurement requirements. The reduction in LSE natural gas-fired capacity is due to the expiration of legacy Qualifying Facility (QF) contracts and contracts executed as part of either the QF/CHP Settlement Agreement or the Long-Term Procurement Plan proceeding.

To determine the supply resources available to PG&E for purposes of calculating its GHG emissions using the CPUC's CSP model, PG&E adjusts the gross capacity value for resources

[32] Does not reflect five-year extension resulting from SB 846 (2021-2022 Reg. Sess.), signed into law on September 2, 2022.

[33] D.20-06-002, p. 91, OP 2, adopted PG&E as the CPE for PG&E's electric distribution service area.

subject to RPS sales through Voluntary Allocation Market Offer (VAMO), large hydroelectric carbon-free energy sales, or capacity allocation through CAM. PG&E's adjusted net capacity by technology for its baseline portfolio is shown in Table 5 and represents the share of capacity from these resources available to bundled customers in the CSP model. The primary difference is between the GHG-free energy resources due to RPS and carbon-free energy sales as well as assumed CPE-procured natural gas resources, which would be allocated through CAM.

TABLE 5
NET BUNDLED CAPACITY SHARE OF BASELINE PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Resource	2024	2026	2030	2035
1	Solar	2,015	2,673	2,682	2,294
2	Large Hydro	954	955	952	950
3	Nuclear	1,118	0	0	0
4	Wind	387	346	295	215
5	Out of State Wind	218	183	182	0
6	Storage				
7	Battery Storage - LSE	2,639	3,784	3,914	3,754
8	Battery Storage - CPE	1	34	34	35
9	Pumped Storage	1,212	1,212	1,212	1,212
10	Small Hydro	236	234	197	158
11	Biomass	189	170	162	131
12	Geothermal	9	55	194	188
13	Biogas	31	49	68	58
14	Natural Gas				
15	Natural Gas - LSE	2,258	1,967	1,569	1,569
16	Natural Gas - CPE	690	2,953	2,737	2,782
17	Total Bundled Capacity	11,955	14,616	14,198	13,347

iii. Resource Additions

PG&E's resource additions are broken out between baseline additions[34], shown in Table 6, and incremental resource additions for meeting the two Conforming portfolio and ATE Alternative portfolio IRP requirements, shown in Tables 7 through 9. The baseline resource additions in Table 6 reflect the resources PG&E plans to add as a result of procurement mandates already authorized by the Commission and are the same for all three portfolios. This includes resources that have already been contracted with and are not yet on-line and mandated or authorized

[34] Defined as projects expected to begin deliveries on January 1, 2023 or later.

resources that PG&E had not contracted for prior to the submittal of its 2022 IRP. The amounts shown are total resource capacities, not reflecting any capacity allocations for CAM cost recovery to the extent it is applicable. This list also does not include any investments by customers or third parties in DERs or investments in EE, which are modeled as load modifiers based on the IEPR forecast values.

TABLE 6
BASELINE CUMULATIVE NEW RESOURCE ADDITIONS (MW)

Line No.	Technology	2024	2026	2030	2035
1	**Biogas**				
2	SB1122/BioMAT	0	19	39	39
3	**Biomass**				
4	SB1122/BioMAT	20	27	53	53
5	ReMAT	0	0	46	46
6	2021 IRP (2023-26 Mid-Term Reliability (MTR))	11	11	11	11
7	**Biomass Subtotal**	**31**	**38**	**110**	**110**
8	**Wind**				
9	ReMAT	0	0	9	24
10	**Solar PV**				
11	ReMAT	3	15	39	39
12	GTSR/DAC	155	155	155	155
13	RPS (RFO)	74	74	74	74
14	2021 IRP (2023-26 MTR)	0	695	695	695
16	**Geothermal**				
17	2021 IRP (2023-26 MTR)	0	50	200	200
18	**Small Hydro**				
19	ReMAT	6	6	6	6
20	**Storage**				
21	AB 2514/IOU Target	35	35	35	25
22	Res. E-4909/Local Deficiency	75	75	75	75
23	Summer Emergency Reliability	10	10	10	0
24	2019 IRP (2021-23 Electric System Reliability)	220	220	220	220
25	2021 IRP (2023-26 MTR)	1,324	2,419	2,550	2,550
26	2021 PSP	0	145	145	145
27	**Storage Subtotal**	**1,664**	**2,904**	**3,035**	**3,015**
28	Total Portfolio Resource Additions	1,932	3,955	4,362	4,357

Baseline portfolio additions are expected as a result of the following activities:

a) **Existing Contracts:** As a result of procurement done through PG&E's RPS RFOs, RAM, ReMAT, and BioMAT programs, PG&E has executed contracts with solar PV and biomass resources that are expected to begin delivering energy for PG&E's bundled customers by 2024.[35] In addition, several energy storage contracts from the 2019 and 2021 IRP Procurement Track decisions, AB 2514 storage target, local area deficiency (E-4909), and Summery Emergency Reliability procurement are expected to come online by 2024.

b) **RPS Resource Procurement:** PG&E forecasts procurement of additional bioenergy, solar, and wind resources through the Commission's existing mandated procurement programs (e.g., BioMAT, ReMAT, RAM/PV RAM).[36] Additionally, PG&E anticipates it will procure bioenergy, solar, and geothermal resources in order to meet part of its remaining 2021 IRP procurement decision obligations.

c) **Energy Storage Procurement:** In addition to the energy storage projects PG&E already has under contract, PG&E plans to procure additional energy storage resources to meet part of its remaining 2021 IRP procurement decision obligations, including long-duration storage resources. PG&E was also ordered in the decision adopting the 2021 IRP PSP to pursue procurement of energy storage resources in response to transmission solutions identified in the California System Operator's 2020-2021 Transmission Planning Process (TPP).[37]

After accounting for these baseline resource additions as well as existing resources in PG&E's portfolio, Tables 7 through 9 show the additional resources that PG&E identified using its BPOT model that would be needed to meet its different bundled IRP planning compliance obligations, including GHG emission targets, for its two Conforming portfolios and ATE Alternative portfolio. As described in Appendix 1, the set of candidate resources assumed to be available to PG&E are constrained to be consistent with the resource additions identified in the CPUC's update to the 2021 PSP.

[35] For additional information, see A.22-05-029, PG&E's 2023 ERRA Forecast Application, prepared testimony Chapter 6, that provides an overview of PG&E's RPS-eligible contracts, <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=704998> (as of Oct. 25, 2022). PG&E's wholesale electric power procurement website provides information regarding historical RPS RFO and related RPS solicitations, <https://www.pge.com/en_US/for-our-business-partners/energy-supply/wholesale-electric-power-procurement/wholesale-electric-power-procurement.page> (as of Oct. 25, 2022).

[36] These mandated procurement programs are described in PG&E's Final 2019 Renewable Energy Procurement Plan (Jan. 29, 2020), Rulemaking (R.)18-07-003, Section 4.C, <https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=593454)> (as of Oct. 25, 2022).

[37] D.22-02-004, pp. 194-195, OP 12 and OP 13.

TABLE 7
ADDITIONAL PROCUREMENT FOR 30 MMT CONFORMING PORTFOLIO (MW)

Line No.	Technology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	127	127
3	Kramer	0	0	444	444
4	Riverside	0	0	711	711
5	Tehachapi	0	0	594	594
6	Wind				
7	Baja California	0	0	120	120
8	Carrizo	0	0	57	57
9	Central Valley	0	0	35	35
10	Humboldt	0	0	7	7
11	Kern Greater Carrizo	0	0	12	12
12	Northern California	0	0	173	173
13	Solano	0	0	112	112
14	Southern Nevada	0	0	88	88
15	Southwest Existing	0	0	53	53
16	Tehachapi	0	0	55	55
17	New Transmission Wind				
18	Humboldt Bay Offshore	0	0	0	179
19	Morro Bay	0	0	39	620
20	New Mexico	0	0	500	500
21	Wyoming	0	0	89	466
22	Storage				
23	Battery Storage	0	0	0	1,167
24	Total Portfolio Resource Additions	0	0	3,217	5,521

TABLE 8
ADDITIONAL PROCUREMENT FOR 25 MMT CONFORMING PORTFOLIO (MW)

Line No.	Technology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	166	166
3	Imperial	0	0	0	38
4	Kramer	0	0	754	754
5	Riverside	0	0	646	646
6	Tehachapi	0	0	113	543
7	Wind				
8	Baja California	0	0	109	109
9	Carrizo	0	0	52	52
10	Central Valley	0	0	31	31
11	Humboldt	0	0	6	6
12	Kern Greater Carrizo	0	0	0	11
13	Northern California	0	0	157	157
14	Solano	0	0	102	102
15	Southern Nevada	0	0	0	80
16	Southwest Existing	0	0	91	91
17	Tehachapi	0	0	50	50
18	New Transmission Wind				
19	Humboldt Bay Offshore	0	0	0	247
20	Morro Bay	0	0	0	564
21	New Mexico	0	0	455	455
22	Wyoming	0	0	423	423
23	Storage				
24	Battery Storage	0	0	0	1,102
25	Total Portfolio Resource Additions	0	0	3,156	5,627

TABLE 9
ADDITIONAL PROCUREMENT FOR 30 MMT ATE ALTERNATIVE PORTFOLIO (MW)

Line No.	Technology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	29	29
3	Kramer	0	0	121	1,072
4	Riverside	0	0	611	833
5	Tehachapi	0	0	567	1,258
6	Southern Nevada	0	0	713	713
7	PG&E	0	0	69	69
8	Wind				
9	Baja California	0	0	120	120
10	Carrizo	0	0	57	57
11	Central Valley	0	0	35	35
12	Humboldt	0	0	7	7
13	Kern Greater Carrizo	0	0	12	12
14	Northern California	0	0	152	152
15	Solano	0	0	112	112
16	Southern Nevada	0	0	88	88
17	Southwest Existing	0	0	53	100
18	Tehachapi	0	0	55	55
19	New Transmission Wind				
20	Humboldt Bay Offshore	0	0	0	321
21	Morro Bay	0	0	39	620
22	New Mexico	0	0	500	500
23	Wyoming	0	0	98	466
24	Storage				
25	Battery Storage	0	0	1,127	4,809
26	Total Portfolio Resource Additions	0	0	4,565	11,429

iv. Resource Sales

PG&E's resource portfolio is expected to be reduced as a result of the following forecasted sales:

a) **RPS Sales:** On May 20, 2021, the Commission adopted Decision (D.)21-05-030, creating significant regulatory changes in how PG&E will be able to manage its RPS-eligible portfolio. The VAMO was adopted for PCIA-eligible resources and applies to all of PG&E's resources that are eligible for PCIA cost recovery, which is a majority of PG&E's RPS portfolio. Under VAMO, PCIA-eligible LSEs have an option to receive an allocation of RPS attributes from the IOUs' PCIA-eligible resources based on each LSE's vintaged load forecast relative to the total PCIA-eligible vintaged load forecast. Declined allocations will be offered for sale by the IOUs through a market offer process established through the RPS proceeding process.

Consistent with PG&E's Draft 2022 RPS Plan, PG&E's forecasted RPS supply positions in its 2022 IRP reflect the assumption that PG&E retains 100 percent of the bundled service customer share of the expected RPS-eligible generation subject to VAMO and that 100 percent of the departed load share is sold as either allocations to departed LSEs or through the market offer process to entities other than PG&E. The sale volumes assumed in PG&E's IRP differ from its RPS Plan due to the IRP scenarios using different bundled load forecasts. However, the amount will be equivalent to the allocation volumes forecasted to be available to departed load. For the 2022 IRP modeling horizon of 2023 through 2035, this represents approximately 115,000 GWh of RPS sales for each of PG&E's portfolios.

b) **Carbon-Free Energy Sales:** In May 2020, the Commission adopted Res.E-5046 to give LSEs within PG&E's TAC area the option to receive a pro-rata allocation of the GHG-free attributes associated with PG&E's large hydroelectric and nuclear carbon-free resources for the remainder of 2020. In subsequent years, PG&E has made available and executed similar agreements with LSEs within PG&E's TAC area. For its 2022 IRP, PG&E assumes that departed LSEs will elect their share of generation volumes from PG&E's large hydroelectric resources from 2023 through 2035 in subsequent, annual sale offerings. This is a conservative assumption as the Commission has not made a determination on how to treat GHG-free energy after 2023.

v. Clean System Power Model Energy Volumes

To calculate PG&E's bundled portfolio GHG emissions for each of the three portfolios using the CPUC's CSP model, PG&E combined the forecasted energy and capacity inputs from the baseline resources presented in Table 5 with the respective resource additions presented in Tables 7 through 9. The resulting forecasted energy volumes representing the three bundled CSP model portfolios is shown in Tables 10 through 12, with each resulting in PG&E meeting its bundled IRP GHG emissions planning targets.

TABLE 10
30 MMT CONFORMING PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2024	2026	2030	2035
1	Demand Inputs				
2	Managed Retail Sales	27,098	27,399	28,020	29,852
3	Behind-The-Meter PV	4,240	4,867	6,226	8,006
4	**Total CSP Demand Inputs**	**31,338**	**32,266**	**34,246**	**37,858**
5	Supply Inputs				
6	Large Hydro	3,082	3,039	2,944	2,801
7	Imported Hydro	1,812	1,815	1,813	1,870
8	Asset Controlling Supplier	0	0	0	0
9	Nuclear	17,098	0	0	0
10	Biogas	130	198	329	268
11	Biomass	1,187	970	797	811
12	Geothermal	140	328	1,429	1,316
13	Small Hydro	521	513	473	374
14	Wind Resources				
15	Wind Baseline California	1,085	556	565	557
16	Wind New PG&E	0	0	935	964
17	Wind New SCE SDG&E	0	0	911	912
18	Wind Pacific Northwest	0	0	0	0
19	Wind Wyoming	0	0	431	2,203
20	Wind New Mexico	0	0	2,224	2,183
21	Wind Offshore Morro Bay	0	0	159	2,660
22	Wind Offshore Humboldt	0	0	0	910
23	Solar Resources				
24	Solar Baseline California	4,215	3,972	3,853	3,132
25	Solar New PG&E	189	336	379	372
26	Solar New SCE SDG&E	0	1,368	7,453	7,037
27	Solar Distributed	0	0	0	0
28	Storage & DR				
29	Shed DR	2	2	1	2
30	Pumped Storage	-712	-693	-772	-783
31	Battery Storage	-586	-973	-1,037	-1,231
32	**Total CSP Supply Input**	**28,162**	**11,433**	**22,888**	**26,358**

TABLE 11
25 MMT CONFORMING PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2024	2026	2030	2035
1	Demand Inputs				
2	Managed Retail Sales	27,098	27,399	28,020	29,852
3	Behind-The-Meter PV	4,240	4,867	6,226	8,006
4	**Total CSP Demand Inputs**	**31,338**	**32,266**	**34,246**	**37,858**
5	Supply Inputs				
6	Large Hydro	3,082	3,039	2,944	2,801
7	Imported Hydro	1,812	1,815	1,813	1,870
8	Asset Controlling Supplier	0	0	0	0
9	Nuclear	17,098	0	0	0
10	Biogas	130	198	329	268
11	Biomass	1,187	970	797	811
12	Geothermal	140	328	1,429	1,316
13	Small Hydro	521	513	473	374
14	Wind Resources				
15	Wind Baseline California	1,083	556	565	557
16	Wind New PG&E	0	0	798	855
17	Wind New SCE SDG&E	0	0	706	920
18	Wind Pacific Northwest	0	0	0	0
19	Wind Wyoming	0	0	1,962	1,936
20	Wind New Mexico	0	0	1,945	1,918
21	Wind Offshore Morro Bay	0	0	0	2,337
22	Wind Offshore Humboldt	0	0	0	1,211
23	Solar Resources				
24	Solar Baseline California	4,215	3,972	3,853	3,132
25	Solar New PG&E	189	336	379	372
26	Solar New SCE SDG&E	0	1,368	6,731	7,679
27	Solar Distributed	0	0	0	0
28	Storage & DR				
29	Shed DR	2	2	1	2
30	Pumped Storage	-703	-728	-791	-736
31	Battery Storage	-587	-969	-1,367	-1,542
32	**Total CSP Supply Input**	**28,170**	**11,401**	**22,567**	**26,083**

TABLE 12
30 MMT ATE PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2024	2026	2030	2035
1	Demand Inputs				
2	Managed Retail Sales	27,602	27,968	30,029	36,401
3	Behind-The-Meter PV	4,535	5,159	6,517	8,292
4	**Total CSP Demand Inputs**	**32,137**	**33,127**	**36,546**	**44,693**
5	Supply Inputs				
6	Large Hydro	3,306	3,254	3,156	2,999
7	Imported Hydro	1,846	1,852	1,943	2,280
8	Asset Controlling Supplier	0	0	0	0
9	Nuclear	17,096	0	0	0
10	Biogas	130	198	329	268
11	Biomass	1,185	969	797	811
12	Geothermal	59	249	1,351	1,316
13	Small Hydro	541	534	493	390
14	Wind Resources				
15	Wind Baseline California	1,083	561	581	616
16	Wind New PG&E	0	0	807	807
17	Wind New SCE SDG&E	0	0	865	994
18	Wind Pacific Northwest	0	0	0	0
19	Wind Wyoming	0	0	440	2,090
20	Wind New Mexico	0	0	2,035	2,035
21	Wind Offshore Morro Bay	0	0	159	2,523
22	Wind Offshore Humboldt	0	0	0	1,549
23	Solar Resources				
24	Solar Baseline California	4,805	6,037	6,250	5,332
25	Solar New PG&E	0	0	199	190
26	Solar New SCE SDG&E	0	0	7,819	11,411
27	Solar Distributed	0	0	0	0
28	Storage & DR				
29	Shed DR	2	2	1	2
30	Pumped Storage	-712	-693	-772	-783
31	Battery Storage	-578	-887	-1,250	-2,035
32	**Total CSP Supply Input**	**28,762**	**12,076**	**25,204**	**32,797**

b. Conforming Portfolios for IRP Compliance

PG&E is submitting two Conforming Portfolios presented in this plan for meeting the requirements described in Section III.b of the IRP filing requirements:

- 30 MMT Conforming Portfolio
- 25 MMT Conforming Portfolio

As described below, both Conforming Portfolios meet the following requirements of SB 350, as codified in Public Utilities Code Section 454.52(a)(1):

454.52(a)(1)(A): As shown in Section III.c, PG&E's Conforming Portfolios meet the assigned LSE GHG planning benchmarks for PG&E in 2030 and 2035.

454.52(a)(1)(B): Figures 3 and 4 show how PG&E's Conforming Portfolios meet the LSE RPS compliance requirements for the IRP study years 2024, 2026, 2030 and 2035, including PG&E's commitment to 70 percent RPS by 2030. Figure 5 shows comparable data for PG&E's 30 MMT ATE Alternative portfolio. In each portfolio, PG&E's RPS position continues to increase beyond 2030 as a result of meeting the IRP GHG emission planning targets for 2035 and California's SB 100 clean energy content requirements.

FIGURE 3
30 MMT CONFORMING PORTFOLIO RPS POSITION (GWH)

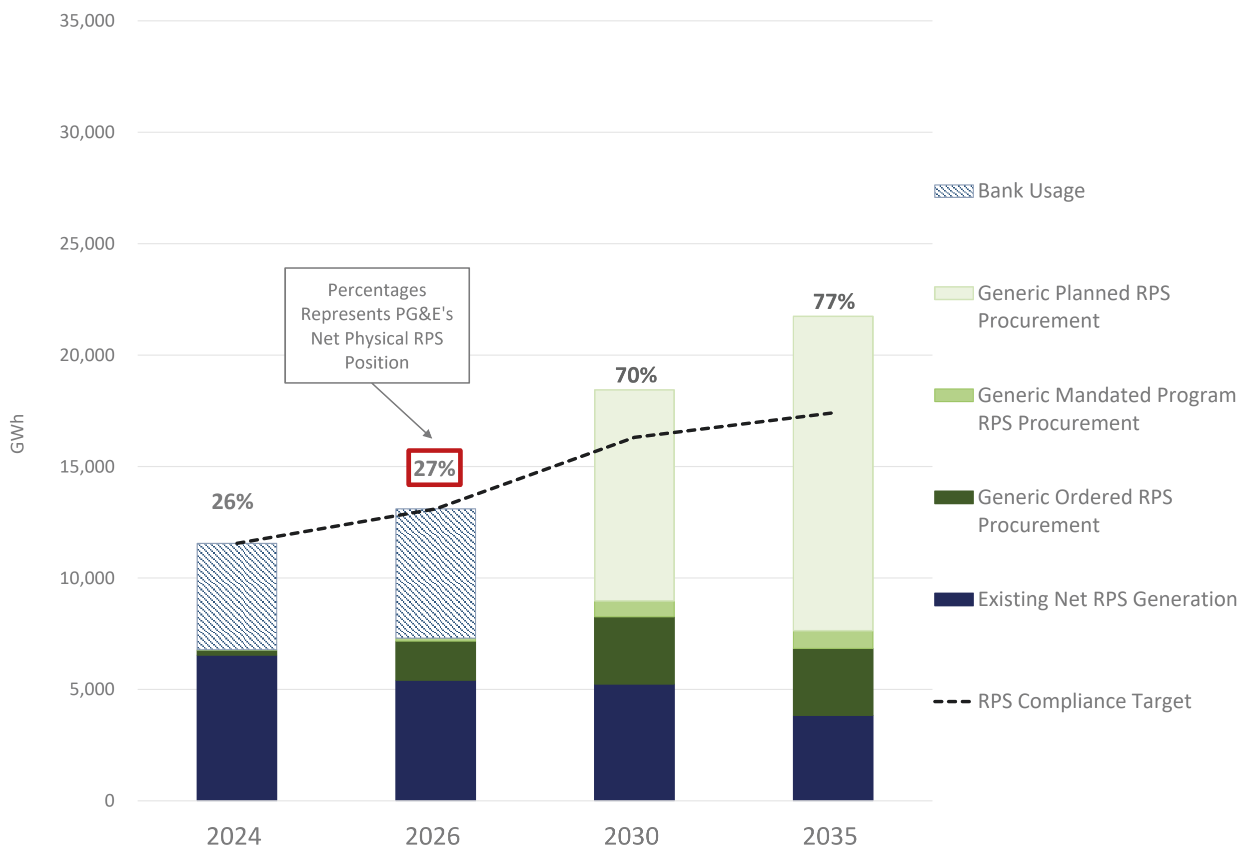


FIGURE 4
25 MMT CONFORMING PORTFOLIO RPS POSITION (GWH)

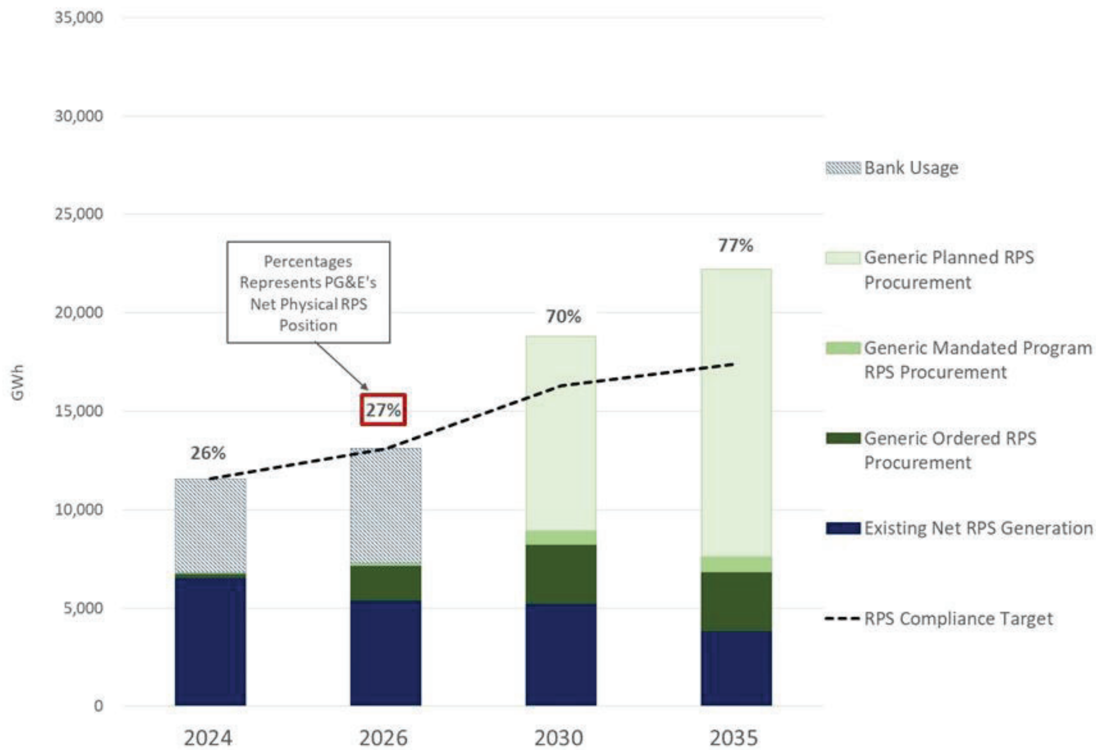
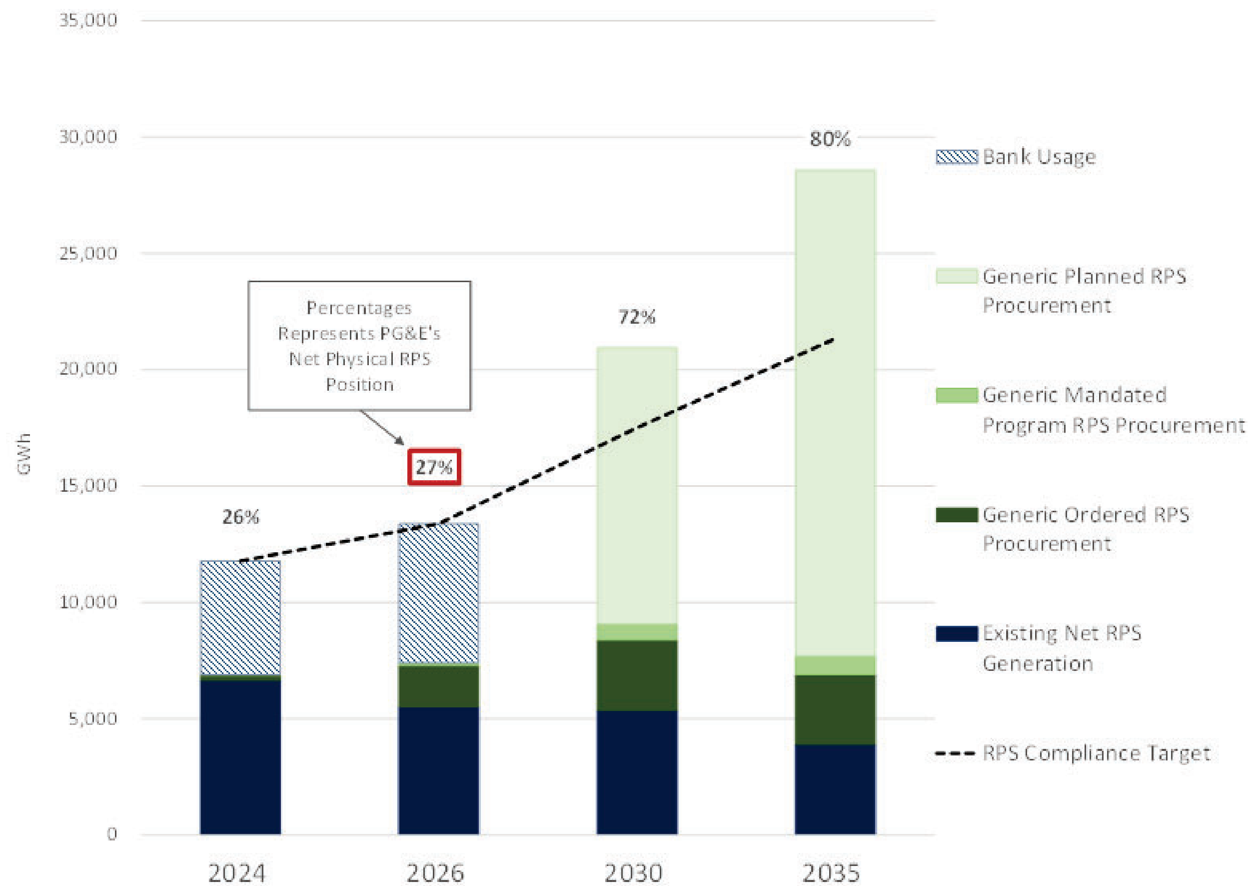


FIGURE 5
30 MMT ATE ALTERNATIVE PORTFOLIO RPS POSITION (GWH)



454.52(a)(1)(C): The revenue requirements and associated bundled generation rates for PG&E's Conforming portfolios are shown in Section III.e. These rates reflect the net impact from PG&E's baseline resource portfolio, which is comprised of existing contracts and utility-owned resources already approved as reasonable by the CPUC as well as additional CPUC ordered procurement, and an optimal mix of future resource additions that meet the bundled portfolio planning constraints utilized in PG&E's BPOT model at the lowest cost.

454.52(a)(1)(D): PG&E's Conforming Portfolios minimize ratepayer bills to the extent feasible through the IRP process. Specifically, PG&E's portfolios do not include any incremental procurement beyond what PG&E expects is needed to meet GHG, RPS, and RA requirements through 2035, with resource additions incorporated gradually over time.

454.52(a)(1)(E): Per the CPUC IRP filing requirements in Section III.f, PG&E's Conforming Portfolios demonstrate meeting the required system RA requirements. For local reliability, PG&E assumes that the CPE will procure at least capacity from thermal resources assumed to be operating through 2035 and located in PG&E local capacity areas in order to ensure local reliability requirements are met. For purposes of calculating PG&E's system RA position in Section III.f, PG&E includes its bundled LSE load share of these local resources.

454.52(a)(1)(F): On August 17, 2017, PG&E informed the Commission of election to comply early with the long-term contracting requirements in subsection (b), starting with the 2017–2020 RPS compliance period. PG&E will continue to comply going forward, as will be reported in its RPS compliance reports.

454.52(a)(1)(G): *"Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."* PG&E's Conforming Portfolios include a diverse set of resources that provide support to CAISO system reliability. PG&E's 2030 portfolios provide 66 percent of its September RA requirement from flexible, non-emitting resources, including hydroelectric, pumped storage, and battery storage.

454.52(a)(1)(H): "*Enhance distribution systems and demand-side energy management.*" PG&E's Action Plan includes extensive demand side procurement activities to support demand side energy management and continuing growth in demand-side energy resources, including energy efficiency, rooftop solar generation, EVs, building electrification, and expanded demand response participation in both CAISO and CPUC DR programs.

454.52(a)(1)(I): "*Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.*" PG&E's Action Plan includes a broad range of programs focused on DACs. These programs include electrification and fuel switching pilots, community solar programs, and clean transportation programs focused on DACs. Additionally, as discussed in the filing, PG&E actively pursues procurement options to improve air quality in DACs.

c. GHG Emissions Results

i. CSP Model Resource Assumptions

a) **GHG-Free Energy Supply:** The GHG-free energy forecast used in PG&E's CSP portfolio is shown in Tables 10 through 12 and consists of PG&E's baseline resources shown in Table 5 as well as the identified additions to meet the IRP planning constraints shown in Tables 7 through 9 for the three presented portfolios. PG&E's portfolio does include non-Portfolio Content Category (PCC) 1 out-of-state (OOS) wind resources, which have been excluded from providing a GHG benefit in the CSP calculator.
b) **Hydro Imports:** Accurately accounting for the attributes associated with hydroelectric energy imported into California requires a level of centralized verification that does not currently exist. It is possible an LSE can show offtake agreements with a hydroelectric provider. However, without a clearinghouse to track the actual energy from each source there is no way to ensure that the IRP avoids double counting. Therefore, PG&E believes a pro-rata allocation of the hydroelectric energy imported

into California is the appropriate way to avoid potential double counting, and PG&E has reflected its pro-rata share in its calculation.

c) **Demand Response:** All customers within PG&E's service area can benefit from PG&E's DR and Demand Response Auction Mechanism (DRAM) programs. Accounting for which customers receive peak load shifting benefits from these programs can be difficult and could result in LSEs showing a load reduction from the same mechanism, leading to potential double counting. PG&E believes a pro-rata allocation of DR capacity is the appropriate way to avoid potential double counting, and PG&E has reflected its pro-rata share in its calculation.

d) **Energy Storage (Capacity Attributes):** PG&E has several contracts with energy storage assets where PG&E is purchasing all of the capacity and counting attributes, but not directly purchasing any energy revenues. PG&E is including these resources in its CSP supply portfolio, which is also In line with the CPUC's CSP portfolio guidance[38].

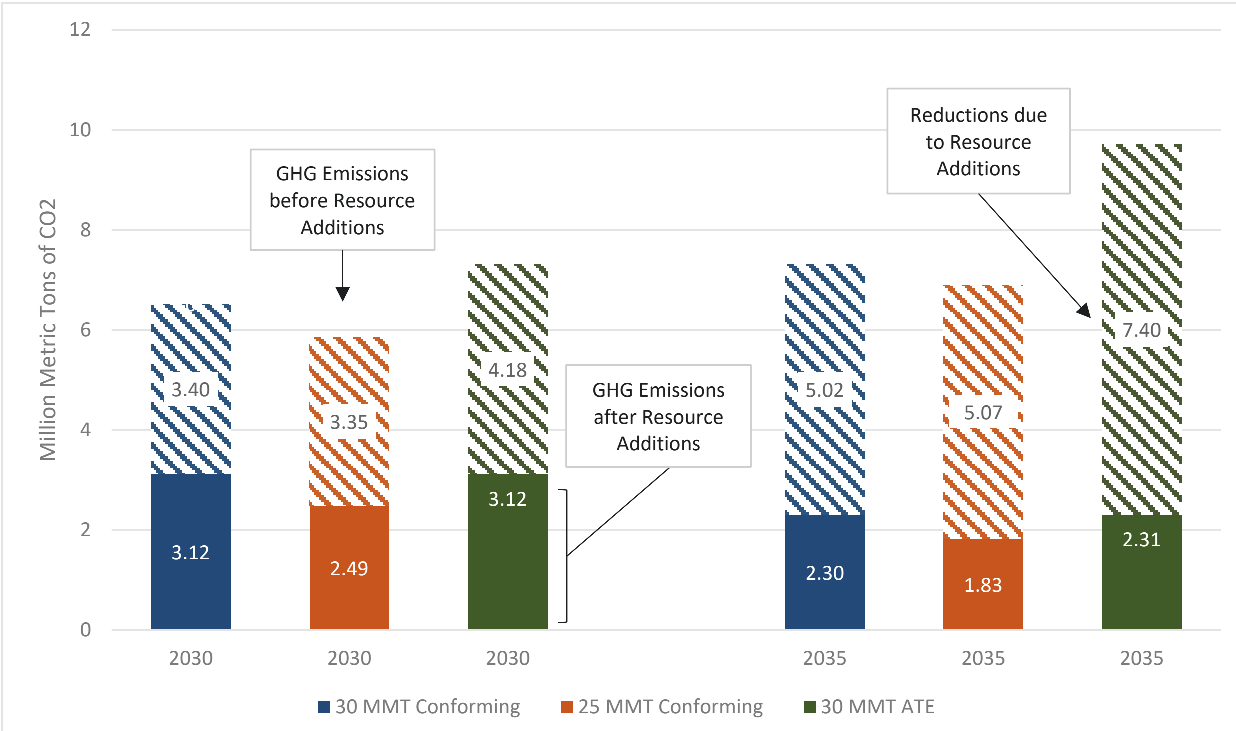
e) **Front-of-the-Meter CHP:** The current CSP model is set up to calculate each LSE's front-of-the-meter CHP emissions based on their respective load share. This does not account for actual potential individual LSE's CHP retirements and assumes there is no reduction in system CHP capacity until after 2030 as California moves towards meeting its SB 100 goals. While the CSP assumption on CHP emissions helps to simplify calculations, it may fail to account for changes individual LSEs are making to reduce CAISO system CHP capacity and consequently GHG emissions.

ii. Scenario GHG Emission Results

As described above, PG&E will need to add additional resources to its baseline portfolio in order to meet its 2030 and 2035 GHG emission targets for its two Conforming and ATE Alternative scenarios. Figure 6 shows the initial gross baseline GHG emission totals as well as the net GHG emissions for each scenario after accounting for the resource additions presented in Tables 7 through 9.

[38] Integrated Resource Planning (R.20-05-003) 2022 IRP Filings, Filing Requirements' Questions and Answers, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2022-filling-requirement-qav2.pdf> (as of Oct. 25, 2022).

FIGURE 6
IRP SCENARIOS CSP GHG EMISSION RESULTS (MMT)



All portfolios presented here meet or exceed their GHG emissions benchmark requirements as documented in Section II.a. For example, for the 30 MMT Conforming case in 2035, the initial gross baseline GHG emissions are 7.32 MMT. This represents the starting point for emissions in this portfolio before any resources incremental to PG&E's baseline portfolio are added. The shaded section of each column represents the GHG emission reductions resulting from the incremental new resource additions. In the example above, this value is 5.02 MMT. Finally, the solid section of each column represents the final GHG emissions totals for each portfolio. In the previous example, this is the initial gross baseline GHG emissions minus GHG reductions due to the addition of new resources, a value of 2.30 MMT. For 2035, all three scenarios reflect GHG emissions below PG&E's 25 MMT target as a result of the resource additions needed to meet PG&E's assumed procurement trajectory to achieve California's SB 100 requirements.

d. Local Air Pollutant Minimization and Disadvantaged Communities

In this section, PG&E describes the local air pollutant emissions from its two Conforming Scenario bundled portfolios and ATE Alternative based on their respective CSP models. PG&E also discusses its efforts to mitigate local air pollutants from its bundled portfolio with early prioritization on DACs. This section also provides insights on customers that reside in DACs and highlights PG&E's programs and regulatory activities that impact DACs.

i. Local Air Pollutants

PG&E's CSP-Tool-calculated portfolio local air pollutant emissions are summarized in Table 13. These emission amounts were determined using the 30 MMT and 25 MMT CSP models and reflect expected reductions in 2030 and 2035 as PG&E adds incremental GHG-free energy resources to its bundled portfolio.

TABLE 13
LOCAL AIR POLLUTANT EMISSIONS (TONS/YEAR)

Line No.	Description	Portfolio	2024	2026	2030	2035
1		30 MMT Conf	429	637	410	373
2	$PM_{2.5}$	25 MMT Conf	429	628	396	362
3		30 MMT ATE	424	632	409	378
4		30 MMT Conf	156	160	136	127
5	SO_2	25 MMT Conf	156	159	134	126
6		30 MMT ATE	156	160	136	127
7		30 MMT Conf	1,310	1,419	1,107	979
8	NOx	25 MMT Conf	1,311	1,415	1,091	978
9		30 MMT ATE	1,305	1,414	1,105	979

ii. Focus on Disadvantaged Communities

PG&E supports the Commission's focus on DACs[39] for this IRP, especially given the high levels of air pollutants historically recorded in DACs by the California Environmental Protection Agency (CalEPA). Many DACs are characterized by high levels of economic hardship and a relatively high energy burden compared to other communities in PG&E's service territory. Additionally, the CalEPA identifies these communities as having the highest percentile of adverse scores pertaining to poor environmental health and air quality. While the issues facing DACs extend far beyond the scope of the CPUC's IRP proceeding, the IRP process is a useful venue to consider how electric sector resource planning and other related decarbonization efforts (such as clean transportation and building electrification) may impact air pollution and DACs. The IRP

[39] For this IRP, DACs are defined as follows based on CalEPA's designation from SB 535: 1) census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0; 2) census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 % of CalEnviroScreen 4.0 cumulative pollution burden scores; 3) census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0; 4) lands under the control of federally recognized Tribes. OEEHHA, SB 535 Disadvantaged Communities, <https://oehha.ca.gov/calenviroscreen/sb535> (as of Oct. 28, 2022).

process also presents an opportunity for LSEs to highlight the breadth of activities and programs impacting DAC.

PG&E provides electric service to 645 census tracts that are classified as a DAC using the guiding definition for this IRP. This corresponds to 0.8 million residential customer accounts, and 0.1 million business customer accounts, and approximately 4,200 residential customer accounts on tribal lands.[40] A full breakdown of PG&E's customers in DACs in comparison to the entire services territory is included in the Tables 14 through 16 below. Of note is the high number of DACs that are present in the Central Valley, resulting in a higher proportion of DAC residential and business customers in the Central Valley than elsewhere in the service territory.

TABLE 14
OVERALL PG&E AND DISADVANTAGED COMMUNITIES POPULATION IN PG&E ELECTRIC SERVICE TERRITORY

Line No.	Customer Types	Overall PG&E	Disadvantaged Communities	Percent of Overall PG&E
1	Residential Customers	4,717,867	802,840	17%
2	Business Customers	487,495	112,052	23%

TABLE 15
REGIONAL DISTRIBUTION OF RESIDENTIAL CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY[41]

Line No.	PG&E Region	PG&E Electric Service Territory Customer Accounts (%)	PG&E Electric Service Territory Residential DAC Accounts (%)
1	Bay Area Region	1,584,204 (34%)	169,941 (21%)
2	Central Valley Region	1,026,583 (22%)	542,180 (68%)
3	North Coast Region	459,471 (10%)	6,019 (1%)
4	North Valley & Sierra Region	659,251 (14%)	48,230 (6%)
5	South Bay & Central Coast Region	988,358 (21%)	36,470 (5%)

[40] All accounts reflect PG&E electric service territory customers. PG&E gas only customers are excluded from this dataset.

[41] This figure is based on the number of residential customer accounts, not the number of residential customers. Some PG&E residential customers may have multiple accounts across PG&E's electric service territory.

Approximately 17 percent of the 4.7 million PG&E electric service territory residential customers live in designated DAC Census Tract Areas. Of these, over two-third of customers (68 percent) are in the Central Valley region, despite the Central Valley region containing only approximately one-fifth of all residential customers in PG&E's electric service territory. Residential customers residing in DACs are more likely to be people of color, as stated in the most recently released CalEnviroScreen report: "The results using the CalEnviroScreen 4.0 scores are consistent with earlier versions of the tool, and reflect racial disparities, with the highest percentages of people of color living in the most highly impacted communities."[42]

TABLE 16

REGIONAL DISTRIBUTION OF BUSINESS ACCOUNTS IN PG&E ELECTRIC TERRITORY[43]

Line No.	PG&E Region	PG&E Business Accounts (%)	DAC Business Accounts (%)
1	Bay Area Region	127,730 (26%)	24,503 (22%)
2	Central Valley Region	128,821 (26%)	71,264 (64%)
3	North Coast Region	54,830 (11%)	1,024 (1%)
4	North Valley & Sierra Region	76,939 (16%)	7,297 (7%)
5	South Bay & Central Coast Region	99,175 (20%)	7,964 (7%)

Approximately 23 percent of PG&E's 487,495 business customers are located in DACs. These businesses are predominantly located in the Central Valley region, with approximately two thirds located in this area compared to only one fourth of all business accounts. Across the entire PG&E electric service territory, businesses in DACs are much more likely than overall businesses to be in wholesale, manufacturing, transportation, construction, retail, and administrative waste industries.

PG&E is focused on minimizing air pollutant emissions from its portfolio for bundled customers with early prioritization of DACs as part of its enterprise goals of providing safe, reliable, affordable energy service while proactively combating climate change. Coupled with efforts to mitigate local air pollutants, PG&E has a broad array of programs that are designed to improve both the air quality and the economic vitality of DACs and low-income demographics in PG&E's service territory. Many of these programs have a specific program focus on DACs, including

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[42] Office of Environmental Health Hazard Assessment, CalEnviroScreen 4.0 (Oct. 2021), p. 15, <https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf> (as of Oct. 25, 2022).

[43] This figure is based on the number of business accounts, not the number of business customers. Some PG&E business customers may have multiple accounts across PG&E's electric service territory.

programs in PG&E's clean transportation portfolio, distributed generation programs, and building electrification programs. A detailed list of programs available to customers residing in DACs is included in Appendix 2: PG&E DAC Programs, and further details on EV and DG programs are included in Section IV.a.x and IV.a.ix, respectively.

PG&E conducts outreach to customers in DACs as a component of many existing programs to ensure that impacted customers and customers qualifying for program assistance are aware of the offerings. Some examples of customer outreach include outreach to eligible customers for income qualified programs such as the California Alternative Rates for Energy (CARE) Program, and outreach to customers in high wildfire threat districts with a high likelihood of being impacted by a Public Safety Power Shutoff (PSPS) event. PG&E conducts much of this outreach through partnerships with Community Based Organizations (CBOs) to leverage local insights and resources to better reach customers. Outreach was not conducted as part of this IRP process due to time constraints, but a plan for outreach and DAC customer input has been developed for future IRPs, which is detailed in Section IV.b of this report. PG&E looks forward to leveraging best practices from other outreach efforts to conduct outreach to DACs as part of future IRP cycles. The process and anticipated impact of such outreach is discussed in further detail in Section IV.b.

e. Cost and Rate Analysis

Table 17 presents baseline scenario revenue requirements and rate analysis and Tables 18 and 19 present the revenue requirements and rate analysis for the 30 and 25 MMT Conforming Portfolios. As required, all three tables are expressed in real 2021 dollars. PG&E's Conforming Portfolios do not incorporate any explicit additional transmission or distribution investments that may be needed to connect new resources and continue reliably serving PG&E's customers. As a result, only the generation revenue requirement varies by scenario.

As ordered, the rate presentation includes both the Simple Average Delivery Rate (SADR) containing the rate components recovered from all PG&E customers, and the Simple Average Bundled Rate (SABR), which includes the bundled generation rate from PG&E's portfolio plus the SADR to determine the average system rate for bundled customers.

As described in Section II of this report, the Conforming Scenarios relied on the Commission's planning assumptions to develop price assumptions used for bundled energy market purchases and revenues for generation market sales. This includes natural gas prices, GHG allowance costs, and REC market prices, with the provided gas price assumptions showing a significant variance compared to actual higher prices observed in late 2021 and 2022. For example, the natural gas average California Citygate price forecast provided by the Commission for July 2022 is $3.89/MMBtu[44] while actual gas prices averaged $7.06/MMBtu[45]. Natural gas prices are a key modeling assumption, and actual prices in the future will impact procurement decisions and costs that could deviate significantly from this forecast.

For the other components of its revenue requirement forecast (transmission, distribution, DSM programs, and other), PG&E created a forecast that incorporates all revenue requirements approved but not yet implemented as well as pending requests. PG&E notes that the rate forecasts provided in the IRP are indicative. Actual realized rates will depend upon future realized market prices, the outcomes of future rate cases, in particular GRCs, other ongoing proceedings, and market conditions. Future rate forecasts will reflect the information available at that time and may lead to updated revenue requirements associated with additional (or reduced) future costs including, but not limited to, T&D upgrades, grid modernization costs, clean transportation infrastructure costs, and changes based on PG&E's cost of capital.

The revenue requirement and rate differences between the two scenarios is negligible. In 2035, the 30 MMT scenario's SABR in 2021 dollars is 28.68 cents per kWh and in the 25 MMT scenario, the SABR in 2021 dollars is 28.62 cents per kWh. The small rate difference in the generation revenue requirements for the two scenarios is primarily due to different forward market power prices given the two different system-level portfolios, which impacts the market value of supply resource sales and bundled load purchases. In 2035, the 30 MMT Conforming scenario's bundled generation rate in 2021 dollars is 8.03 cents per kWh and in the 25 MMT Conforming scenario, the bundled generation rate is 7.97 cents per kWh[46].

PG&E is concerned that the revenue requirements do not fully capture the increase in costs that are expected in order to implement either the 30 MMT or 25 MMT scenarios. For example, PG&E believes the system will incur additional costs not identified in the IRP to create the flexibility and capacity needed to operate a system that meets California's clean energy and carbon neutrality goals. Gaps in T&D costs are addressed in the Section III.e.i below.

[44] Calculated as the average of the PG&E Citygate and SoCalGas Citygate prices from the CEC's June 2020 gas price forecast in nominal dollars.

[45] Prices were converted from $/Mcf to $/MMBtu using a conversion factor of 1.035 MMBtu/Mcf. Natural Gas Citygate Prices in California can be found on the EIA website, <https://www.eia.gov/dnav/ng/hist/n3050ca3m.htm> (as of Oct. 25, 2022).

[46] There is a slight increase in PG&E's bundled nominal generation rate from 2023 to 2035 for the two Conforming scenarios.

TABLE 17
REVENUE REQUIREMENTS AND BUNDLED SYSTEM AVERAGE RATES FOR BASELINE SCENARIO
(2021 $MILLIONS)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 6,633	$ 10,410	$ 8,644	$ 9,216	$ 9,337	$ 9,549	$ 9,733	$ 9,957	$ 10,193	$ 10,437	$ 10,689	$ 10,949	$ 11,219
2	Transmission	$ 2,509	$ 2,490	$ 2,937	$ 3,068	$ 3,218	$ 3,371	$ 3,536	$ 3,718	$ 3,910	$ 4,111	$ 4,327	$ 4,556	$ 4,800
3	Generation	$ 2,529	$ 2,594	$ 2,459	$ 2,345	$ 2,346	$ 2,261	$ 2,296	$ 2,261	$ 2,285	$ 2,253	$ 2,216	$ 2,186	$ 2,150
4	Demand Side Programs	$ 575	$ 425	$ 362	$ 361	$ 359	$ 355	$ 351	$ 348	$ 333	$ 328	$ 323	$ 318	$ 314
5	Other	$ 738	$ 622	$ 612	$ 578	$ 569	$ 560	$ 551	$ 543	$ 535	$ 527	$ 519	$ 512	$ 505
6 (sum lines 1-5)	Baseline Revenue Requirement	$ 12,985	$ 16,541	$ 15,014	$ 15,568	$ 15,828	$ 16,095	$ 16,467	$ 16,828	$ 17,255	$ 17,656	$ 18,074	$ 18,521	$ 18,987
7	System Sales (GWh)	74,578	75,074	75,437	75,816	76,245	76,654	77,211	77,800	78,519	79,153	79,919	80,684	81,536
8	Bundled Sales (GWh)	26,903	27,098	27,257	27,399	27,549	27,650	27,879	28,020	28,356	28,613	29,044	29,434	29,852
9	System Average Delivery Rate (¢/kWh	14.02	18.58	16.64	17.44	17.68	18.05	18.35	18.72	19.07	19.46	19.84	20.25	20.65
10	Bundled Generation Rate (¢/kWh)	9.40	9.57	9.02	8.56	8.51	8.18	8.24	8.07	8.06	7.87	7.63	7.43	7.20
11	System Average Bundled Rate (¢/kWh	23.42	28.15	25.66	26.00	26.20	26.22	26.59	26.79	27.12	27.33	27.47	27.67	27.85

(a) Totals may not add due to rounding.

(b) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

(c) Note that Line 2 represents generation costs for only PG&E Bundled customers while Lines 1, 2, 4, and 5 represent costs for all PG&E System customers. In Line 6, PG&E sums the values for Lines 1 through 5 as required although they have different representations.

TABLE 18
REVENUE REQUIREMENTS AND BUNDLED SYSTEM AVERAGE RATES FOR 30 MMT CONFORMING PORTFOLIO
(2021 $MILLIONS)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 6,633	$ 10,410	$ 8,644	$ 9,216	$ 9,337	$ 9,549	$ 9,733	$ 9,957	$ 10,193	$ 10,437	$ 10,689	$ 10,949	$ 11,219
2	Transmission	$ 2,509	$ 2,490	$ 2,937	$ 3,068	$ 3,218	$ 3,371	$ 3,536	$ 3,718	$ 3,910	$ 4,111	$ 4,327	$ 4,556	$ 4,800
3	Generation	$ 2,508	$ 2,576	$ 2,457	$ 2,333	$ 2,381	$ 2,400	$ 2,389	$ 2,372	$ 2,436	$ 2,433	$ 2,461	$ 2,397	$ 2,397
4	Demand Side Programs	$ 575	$ 425	$ 362	$ 361	$ 359	$ 355	$ 351	$ 348	$ 333	$ 328	$ 323	$ 318	$ 314
5	Other	$ 738	$ 622	$ 612	$ 578	$ 569	$ 560	$ 551	$ 543	$ 535	$ 527	$ 519	$ 512	$ 505
6 (sum lines 1-5)	30 MMT Conforming Portfolio Revenue Requirement	$ 12,964	$ 16,523	$ 15,012	$ 15,556	$ 15,863	$ 16,235	$ 16,560	$ 16,939	$ 17,406	$ 17,836	$ 18,319	$ 18,733	$ 19,234
7	System Sales (GWh)	74,578	75,074	75,437	75,816	76,245	76,654	77,211	77,800	78,519	79,153	79,919	80,684	81,536
8	Bundled Sales (GWh)	26,903	27,098	27,257	27,399	27,549	27,650	27,879	28,020	28,356	28,613	29,044	29,434	29,852
9	System Average Delivery Rate (¢/kWh	14.02	18.58	16.64	17.44	17.68	18.05	18.35	18.72	19.07	19.46	19.84	20.25	20.65
10	Bundled Generation Rate (¢/kWh)	9.32	9.50	9.02	8.51	8.64	8.68	8.57	8.47	8.59	8.50	8.47	8.14	8.03
11	System Average Bundled Rate (¢/kWh	23.34	28.08	25.66	25.96	26.33	26.73	26.92	27.19	27.66	27.96	28.32	28.39	28.68

(a) Totals may not add due to rounding.

(b) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

(c) Note that Line 2 represents generation costs for only PG&E Bundled customers while Lines 1, 2, 4, and 5 represent costs for all PG&E System customers. In Line 6, PG&E sums the values for Lines 1 through 5 as required although they have different representations.

TABLE 19
REVENUE REQUIREMENTS AND BUNDLED SYSTEM AVERAGE RATES FOR 25 MMT CONFORMING PORTFOLIO
(2021 $MILLIONS)

Line No.	Cost Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Distribution	$ 6,633	$ 10,410	$ 8,644	$ 9,216	$ 9,337	$ 9,549	$ 9,733	$ 9,957	$ 10,193	$ 10,437	$ 10,689	$ 10,949	$ 11,219
2	Transmission	$ 2,509	$ 2,490	$ 2,937	$ 3,068	$ 3,218	$ 3,371	$ 3,536	$ 3,718	$ 3,910	$ 4,111	$ 4,327	$ 4,556	$ 4,800
3	Generation	$ 2,529	$ 2,594	$ 2,459	$ 2,345	$ 2,381	$ 2,342	$ 2,441	$ 2,454	$ 2,499	$ 2,483	$ 2,440	$ 2,412	$ 2,379
4	Demand Side Programs	$ 575	$ 425	$ 362	$ 361	$ 359	$ 355	$ 351	$ 348	$ 333	$ 328	$ 323	$ 318	$ 314
5	Other	$ 738	$ 622	$ 612	$ 578	$ 569	$ 560	$ 551	$ 543	$ 535	$ 527	$ 519	$ 512	$ 505
6 (sum lines 1-5)	25 MMT Conforming Portfolio Revenue Requirement	$ 12,985	$ 16,541	$ 15,014	$ 15,568	$ 15,864	$ 16,177	$ 16,612	$ 17,021	$ 17,469	$ 17,886	$ 18,297	$ 18,748	$ 19,216
7	System Sales (GWh)	74,578	75,074	75,437	75,816	76,245	76,654	77,211	77,800	78,519	79,153	79,919	80,684	81,536
8	Bundled Sales (GWh)	26,903	27,098	27,257	27,399	27,549	27,650	27,879	28,020	28,356	28,613	29,044	29,434	29,852
9	System Average Delivery Rate (¢/kWh	14.02	18.58	16.64	17.44	17.68	18.05	18.35	18.72	19.07	19.46	19.84	20.25	20.65
10	Bundled Generation Rate (¢/kWh)	9.40	9.57	9.02	8.56	8.64	8.47	8.76	8.76	8.81	8.68	8.40	8.19	7.97
11	System Average Bundled Rate (¢/kWh	23.42	28.15	25.66	26.00	26.33	26.52	27.11	27.48	27.88	28.14	28.24	28.44	28.62

(a) Totals may not add due to rounding.

(b) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

(c) Note that Line 2 represents generation costs for only PG&E Bundled customers while Lines 1, 2, 4, and 5 represent costs for all PG&E System customers. In Line 6, PG&E sums the values for Lines 1 through 5 as required although they have different representations.

i. Gap in Transmission and Distribution Cost Assumptions

Over the coming decades California will need to invest billions of dollars to build new transmission & distribution to bring on the resource capacity necessary to meet growing customer electric demands and achieve the SB 100 target of 100 percent clean energy sales by 2045. These required upgrades will not only encompass the high-voltage transmission lines needed to access new in-state & OOS resources, but also must be made at the distribution level to accommodate the growing loads from residential electrification and EV penetration. In the most recent publication of CAISO's 20-Year Transmission Outlook[47], the study suggests that in order bring on 120.8 GW necessary to serve CAISO's 2040 load demand, the transmission development cost is estimated to be around $30.5 Billion. While this study largely focuses on transmission, additional costs required to upgrade substations & distribution circuits will need to be considered. One estimate of such costs comes from the Energy Institute @ Haas[48] which estimates in PG&E territory alone, these costs could be substantial, adding at least $1 billion and potentially over 10 billion to PG&E's rate base by 2050. Further analysis and future studies will be required to better understand the total transmission & distribution infrastructure investments more accurately at the CAISO level.

f. System Reliability Analysis

Maintaining system reliability is of paramount importance to the IRP process. A robust reliability assessment is a critical component of the long-term procurement plan process and foundational reliability issues should not be overlooked as the Commission analyzes the aggregated LSE Plans. Indeed, without verifying that the PSP meets local, system, and flexible reliability needs, the Commission cannot confirm the PSP will reliably meet its GHG reduction goals.

As required by the 2022 IRP filing requirements for LSEs, Table 20 and Figure 7 demonstrate PG&E meeting the reliability requirements for its Conforming 30 MMT scenario and Table 21 and Figure 8 demonstrate PG&E meeting the reliability requirements for its Conforming 25 MMT scenario. These results are based on the RDT portfolios for both Conforming scenarios.

[47] CAISO, 20-Year Transmission Outlook (Jan. 31, 2022) Draft, <http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf> (as of Oct. 25, 2022).

[48] Fowlie, Meredith, What Will Electrification Cost (the Distribution System)? (June 27, 2022), Energy Institute Blog, UC Berkeley, <https://energyathaas.wordpress.com/2022/06/27/what-will-electrification-cost-the-distribution-system/> (as of Oct. 25, 2022).

TABLE 20
30 MMT CONFORMING PORTFOLIO RELIABILITY (MW)
CONFIDENTIAL

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LSE reliability need (MW)	[redacted]											
ELCC by contract status (effective MW)												
Online												
Development												
Review												
PlannedExisting												
PlannedNew												
BTM PV												
LSE total supply (effective MW)												
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)												

FIGURE 7
30 MMT CONFORMING PORTFOLIO RELIABILITY (MW)
CONFIDENTIAL

[redacted]

TABLE 21
25 MMT CONFORMING PORTFOLIO RELIABILITY (MW)
CONFIDENTIAL

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LSE reliability need (MW)	[redacted]											
ELCC by contract status (effective MW)												
Online												
Development												
Review												
PlannedExisting												
PlannedNew												
BTM PV												
LSE total supply (effective MW)												
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)												

FIGURE 8
25 MMT CONFORMING PORTFOLIO RELIABILITY (MW)
CONFIDENTIAL

[redacted]

g. High Electrification Planning

PG&E supports the CPUC's consideration of planning for higher customer loads due to growth in electrification and is requesting that the CPUC base its resource planning and PG&E's request for resource procurement on the ATE load forecast. As shown in Table 9, PG&E will need to add additional resources in order to meet PG&E's portfolio planning constraints as compared to the resource additions for the two Conforming portfolios shown in Tables 7 and 8. Table 22 shows the incremental resource additions identified for PG&E's 30 MMT ATE alternative portfolio. As a result of resource additions needed to meet the GHG-free energy trajectory necessary for achieving California's SB 100 goals, Figure 6 shows that PG&E's ATE portfolio satisfies PG&E's 25 MMT emissions target for 2035. Therefore, it wasn't necessary for PG&E to explicitly model a 25 MMT emissions target portfolio since the same resource additions are needed for both the 30 MMT and 25 MMT portfolios to meet California's GHG-free energy requirements.

TABLE 22
INCREMENTAL ATE RESOURCE ADDITIONS

Line No.	Resource Type	MW	GWH	2035 GHG target	Transmission Zone[49]	Substation/ Bus[50]	Alternative location[50]	Note
1	Solar PV							
2	Arizona	(137)	(392)	Both	AZ_WE	NA	NA	
3	Imperial	(38)	(110)	Both	SCADSNV_Z3_GreaterImperial	NA	NA	
4	Kramer	318	999	Both	GK_Z2_InyokernAndNorthOfKramer	NA	NA	
5	Riverside	186	648	Both	SCADSNV_Z4_RiversideAndPalmSprings	NA	NA	
6	Southern_Nevada	713	2,070	Both	NV_EA	NA	NA	
7	PG&E	69	190	Both	SPGE_Z1_Westlands	NA	NA	
8	Tehachapi	714	2,049	Both	Tehachapi	NA	NA	
9	Wind							
10	Baja	11	24	Both	BJ_SO	NA	NA	
11	Carrizo	5	9	Both	SPGE_Z3_Carrizo	NA	NA	
12	Central Valley	3	5	Both	SPGE_Z4_CentralValleyAndLosBanos	NA	NA	
13	Humboldt	1	1	Both	Norcal_Z2_Humboldt	NA	NA	
14	Kern_Greater_Carrizo	1	2	Both	SPGE_Z2_KernAndGreaterCarrizo	NA	NA	
15	Northern California	(5)	(17)	Both	LassenCountyPartial	NA	NA	
16	Solano	10	18	Both	Norcal_Z4_Solano	NA	NA	
17	Southern_Nevada	8	18	Both	NV_WE	NA	NA	
18	SW Existing	9	20	Both	SW_Ext_Tx	NA	NA	
19	Tehachapi		11	Both	Tehachapi	NA	NA	
20	New Transmission Wind					NA	NA	
21	Humboldt_Bay_Offshore	75	338	Both	Humboldt_Bay	NA	NA	
22	Morro	56	186	Both	Morro_Bay	NA	NA	
23	New_Mexico	46	117	Both	NM_EA	NA	NA	
24	Wyoming	42	154	Both	WY_EA	NA	NA	
25	Storage							
26	Battery Storage	3,707		Both	NA	NA	NA	
27	Total	5,796	6,340					

49 For Resolve resource names that are mapped to more than one electrical zone, PG&E has listed the electrical zone that is associated with the highest remaining resource potential as indicated in CPUC IRP RESOLVE_Resource Costs and Build_2022-06-17.xlm (Resolve Supply Curve). File can be found within the linked .zip file: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/zipped-files/resolve-public-release-2022-06-23-lse-plans-filing-requirements.zip (as of Oct. 26, 2022).

50 The incremental ATE resource additions are generic resources and substation location is not available.

h. Existing Resource Planning

For its 2022 IRP portfolios PG&E took a similar approach as it did in its previous 2018 and 2020 IRP plans regarding existing resources. As described in Section III.a, a majority of PG&E's baseline portfolio is comprised of existing resources that are already online and delivering to PG&E's customers, contracted resources that are under development, and planned new resources that PG&E is actively pursuing in response to mandated procurement programs and procurement orders such as the 2021 IRP (2023-26 MTR) procurement decision. PG&E's IRP portfolios do not reflect any re-contracting with PG&E's existing baseline GHG-free resources when their current contracts expire nor future contracts with other existing GHG-free resources. The portfolio additions presented in Tables 7 through 9 are all identified as 'planned new' resources in PG&E's RDT.

As described in Section III.a.iv, given the limited consideration of local reliability planning in the IRP currently, PG&E's baseline portfolio does include an assumption regarding future contracts with natural gas-fired generators in order to ensure local reliability requirements are being met in PG&E's service territory. Specifically, PG&E assumes that all of the non-utility owned natural gas-fired generators located within PG&E local capacity areas will sign contracts with the CPE and have their reliability attributes proportionally allocated to LSEs within PG&E's service area.[51] This assumption is consistent with the CPUC's updated PSP portfolio, which assumes that all of these resources are available to the CAISO through the IRP planning horizon, as well as PG&E's bundled portfolio that does not include any re-contracting with natural gas-fired generators.

The issue of future contract assumptions for existing resources, in particular GHG-free resources, is critical for ensuring that the needed amount of 'planned new' resources is developed over time and developed equitably across all LSEs. Given the difficulties that individual LSEs face regarding identifying an existing resource for future procurement that is not also being identified by another LSE, the CPUC should consider proportionally allocating the energy and reliability attributes of existing generators for all years after their existing contracts expire through their planned retirement date as part of their standard IRP planning assumptions.[52] This would ensure a more equitable representation of planned new procurement across LSEs within their IRPs while actual future LSE procurement will likely be a combination of agreements with both new and existing generators.

[51] Consistent with the 2022 IRP filing requirements, PG&E is only including its bundled load share of assumed future CPE procurement in its RDT.

[52] Similar to the IFM CHP resource allocation methodology currently implemented in the CSP model.

i. Hydro Generation Risk Management

As presented in Tables 4 and 5, PG&E's bundled customers rely on a variety of generation technology types for providing carbon-free energy and system capacity. While the proportional contribution differs between energy and capacity, hydroelectric resources play a critical role in PG&E meeting both its reliability and GHG emission planning requirements.

The following sections provide additional detail regarding PG&E's hydroelectric resources and their expected energy and system reliability supply as well as associated risks for each.

i. Risk of in-state drought

A. Hydro Generation for 2022 IRP

For the 2022 IRP, PG&E modified 15-year historical average hydroelectric generation conditions to account for the future impacts of climate change and FERC relicensing. This assumption reflects lower generation than the 30-year historic average used in PG&E's 2020 IRP filing. A summary of these changes include:

1) Moving to a 15-year average results in lower generation than a 30-year average. This decrease reflects potential near-term climate change impacts, including years with warmer temperatures, decreased snowpack, and flood affects, as well as the recent extreme droughts and other watershed changes; but it also includes the larger impact to-date from updated license conditions (less generation) as well as additional outage time and spills in recent years. PG&E also adjusted the 15-year average to remove mothballed units from the forecast.
2) The impacts of climate change under the Representative Concentration Pathway 8.5 (RCP 8.5) 50th percentile case reduce hydroelectric generation as the forecast period progresses. The CPUC requires IOUs to use the RCP 8.5 scenario for planning.[53]
3) Expected FERC license conditions which result in less water allocated to hydroelectric generation.

PG&E utilizes a fifteen-year performance average to mitigate year-to-year variability. It accounts for hydrological variability (e.g., cycle of droughts and wet years) but prioritizes more recent years than a 30-year forecast where the impacts of climate change are more apparent. Additionally, the CEC utilized a 15-year historic average assumption in their 2021 IEPR.[54]

Based on this approach, PG&E's annual hydroelectric generation forecast in the 2022 IRP is approximately 15-21 percent lower using the most recent long-term average analysis compared

[53] D.19-10-054, p. 57, OP 4.

[54] CEC Staff Members, Final 2021 IEPR, Volume III: Decarbonizing the State's Gas System, (Mar. 2022) p. F-2, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=242233> (as of Oct. 25, 2022).

to a 30-year historic average. The hydroelectric generation assumption is used in the forecasts of energy production, GHG emissions and expected costs.

B. Comparison to Updated Preferred System Portfolio

As described above, PG&E currently estimates its hydroelectric generation based on a future-adjusted fifteen-year average hydroelectric generation analysis. The forecasted capacity factor assumption for PG&E's hydroelectric resources begins at 37 percent in 2023 and declines linearly to 34 percent by 2035.[55] By comparison, the capacity factor if calculated under the 30-year historic average methodology would have been 44 percent.

As described in the 2019–2020 IRP Inputs and Assumptions document, the annual hydroelectric generation assumption as part of the representative sampling of days method used by RESOLVE.[56] The daily hydro conditions sampled were specifically based on the 2008, 2009, and 2011 hydro years. Based on the published PSP results, this methodology resulted in a capacity factor assumption of approximately 33 percent for hydroelectric resources within the CAISO.[57]

Compared to PG&E's future-adjusted fifteen-year average, the PSP assumes between approximately 13 percent and 5 percent less generation from hydroelectric resources located within the CAISO.[58] The difference decreases over time as PG&E's assumed capacity factor decreases due to impacts of climate change and relicensing. This equates to approximately 3,000 GWh less in 2023 down to approximately 1,200 GWh less in 2035. Given that PG&E's hydroelectric capacity represents a third of the CAISO's large hydroelectric capacity, PG&E recommends that the CPUC review and update as appropriate the expected generation from hydroelectric resources interconnected to the CAISO. Additionally, PG&E recommends the CPUC consider the impacts of climate change under the RCP 8.5, 50th percentile scenario and account for changes in generation due to future unit relicensing.

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[55] Capacity factors represent the ratio of expected output compared to the maximum output for a unit generating at its maximum capacity for every hour in a year.

[56] CPUC, Inputs & Assumptions: 2019-2020 Integrated Resource Planning (Nov. 2019), p. 68, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/inputs--assumptions-2019-2020-cpuc-irp_20191106.pdf> (as of Oct. 25, 2022).

[57] Derived from the reference system plan results of 22,964 GWh hydroelectric generation from 8,032 MW.

[58] Calculated based on PG&E's future-adjusted 15-year capacity factor of between 37 and 34 percent compared to RESOLVE's 33 percent for hydroelectric resources.

ii. System Reliability

A. Planning Assumptions for Hydro Reliability Supply

PG&E recommends the Commission utilize the methodology from D.20-06-031 for calculating monthly dispatchable hydroelectric Net Qualifying Capacity (NQC) values. This methodology will account for hydrological variability and other operational constraints resulting in more representative reliability planning assumptions for hydroelectric resources.

iii. Risks and Planning

A. GHG Emissions

As described above PG&E currently uses a future-adjusted fifteen-year performance average in its hydroelectric generation forecast to mitigate year-to-year variability, including the impacts of in-state drought. The future-adjusted fifteen-year average is used in the forecasts of GHG emissions, as well as energy production and expected costs.

Compared to PG&E's 2018 IRP, PG&E's bundled customers no longer bear the full risk associated with potentially lower levels of hydroelectric generation. This is due to the re-contracting of carbon-free energy sales that PG&E expects to occur as well as the sale of RPS energy from small hydroelectric resources as a result of implementing VAMO, which reduces PG&E's bundled customer's reliance on generation from utility-owned hydroelectric resources for GHG emissions planning. Further details on this assumption are provided in Section III.a of this report.

B. Reliability Supply

Unlike GHG emissions where fluctuations in annual hydroelectric generation volumes have a direct impact on an LSE's total GHG emissions, in-state drought conditions pose a more limited risk to reliability planning since most of PG&E's hydroelectric resources are flexible and have operational discretion on when and how much to dispatch. Even during drought conditions, the supply of water can be reoptimized and released when and where it is most needed to provide peak hour availability and generate at their respective NQCs. However, that flexibility can be reduced during sustained extreme drought, whereby releases could become constrained by late summer or early winter prior to the onset of precipitation for the next water year.

C. Expected Costs

As with the energy and GHG emission forecasts discussed above, PG&E uses a recent future-adjusted fifteen-year performance average to forecast energy from hydroelectric generation to mitigate year-to-year variability. The cost risk associated with lower-than-forecasted energy production from the hydroelectric resources is not solely borne by PG&E's bundled customers because utility-owned hydroelectric resources are recovered through the PCIA rate. Since a majority of customers in PG&E's service territory are subject to

PCIA charges, PG&E's bundled customers are responsible for less than half of the above market cost from utility-owned hydroelectric resources.[59]

While the expected annual cost impact from in-state drought is relatively flat for long-term position planning, the primary risk posed by in-state drought is associated with the short-term, year-to-year fluctuations in actual hydroelectric generation. Given that the costs for PG&E's hydroelectric resources are predominantly fixed, annual fluctuations in hydroelectric generation resulting from actual hydro conditions impacts the CAISO energy market revenues for hydroelectric resources. The next section provides further detail regarding how PG&E's hedging strategy addresses this short-term hydro condition risk.

D. Hedging and Contingency Planning

PG&E's current hedging strategy addresses near term market price risk exposure for PG&E's bundled customers. As the expected hydroelectric generation is updated based on more recent hydro condition data, PG&E updates its hedge position accordingly to reflect either more or less expected generation due to a wetter or drier hydro year, respectively.

Beyond hedging short term market price risk, PG&E has developed a risk mitigation plan regarding potential large uncontrolled water releases.[60] In its plan PG&E identifies potential risks for large uncontrolled water releases and proposed mitigation actions to address those risks. In addition to addressing safety concerns, the mitigation plan also reduces the potential for lost water supply and, therefore, an associated increase in future GHG emissions due to a reduction in hydroelectric generation.

j. Long-Duration Storage Development

PG&E is in discussions with providers of long-duration storage as part of its MTR solicitations and is also pursuing a pilot project with a long-duration storage provider.

As the state considers long-duration solutions within an optimized portfolio of resources that can meet key IRP objectives, current market and regulatory challenges will need to be addressed, including the following:

- Regulatory clarity on the specific needs that long-duration storage can cost effectively address
- Determination of value of additional duration beyond four-hour needs, in light of the current RA market and procurement models

[59] Based on prescribed PG&E bundled customer sales assumption for the 2019-2020 IRP cycle.

[60] PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020), Chapter 13, Risk Assessment and Mitigation Phase Risk Mitigation Plan: Large Uncontrolled Water Release.

- Consideration of how procurement of large, capital-intensive resources will be accomplished among a large and diverse set of LSEs (e.g., through an expanded use of a central buyer)
- Policy support in legislative and regulatory arenas for cost-recovery mechanisms that ensure that all benefiting customers pay
- Consideration of State funding for pilot and demonstration projects that can help to drive down technology costs

k. Clean Firm Power Planning

PG&E has not identified any clean firm generation resource[61] need incremental to existing procurement orders within its Conforming or Alternative portfolios. Accordingly, the baseline resource additions identified in this section are consistent with the resources identified in the Updated 2021 PSP and no additional transmission need has yet to be identified.

l. Out-of-State Wind Development

PG&E has identified additional OOS wind generation resources within its Conforming and Alternative portfolios. Since PG&E identified new resource additions based on those resources selected by the Updated 2021 PSP, assumptions for these resources, including locations identified, are consistent with the CPUC's analysis, as is the justification for their selection.

The following information is also provided in Section IV.a.iv of the Action Plan below as requested by the Commission:

PG&E does not have specific procurement activities for out-of-state (OOS) wind, though it continues to monitor the regulatory processes, including the CAISO consideration of transmission to connect OOS wind areas to California, and the commercial prospects for wind technologies to be incorporated into PG&E's portfolio.

Generally, PG&E supports California accessing OOS wind as an option to meet its clean energy goals while ensuring system reliability and customer affordability, and PG&E itself is interested in investigating procurement of OOS wind to meet its own clean energy goals. However, PG&E believes that CAISO stakeholders (and particularly LSEs) need additional information on the status of OOS wind project development in the various states in the WECC and cost-effectiveness information on the various potential transmission lines that could bring OOS

[61] 2022 Narrative Template (June 15, 2022), p. 15, "*clean firm generation (with an annual capacity factor of at least 80 percent) resources that are not subject to use limitations or are weather dependent. The type of resource described here must be a generating resource, not storage, able to generate when needed, for as long as needed, and may not have any on-site emissions, except if the resource otherwise qualifies under the Renewables Portfolio Standard (RPS) program eligibility requirements.*"

wind into California to assess which line would be most cost-effective for CAISO to commit to and put into its rate base.

m. Offshore Wind Planning

PG&E has identified additional OSW generation resources within its Conforming and Alternative portfolios. Since PG&E identified new resource additions based on those resources selected by the Updated 2021 PSP, assumptions for these resources, including locations identified, are consistent with the CPUC's analysis, as is the justification for their selection. These resources are differentiated between the central coast (Morro Bay) and the north coast (Humboldt).

In August 2022, the CEC set forth a planning goal for California to interconnect between 2,000 MW and 5,000 MW of OSW resources by 2030 and 25,000 MW by 2045[62] in a process required by AB 525 (Chiu, 2021). At the CAISO level, the CPUC's Updated 2021 PSP includes only 195 MW of OSW by 2030. However, only two years later (by 2032), the Plan calls for 2,502 MW of OSW which is within the CEC's planning range. This then increases to 4,707 MW in 2035, a value that is then constant through 2045. This delay in reaching the planning target is indicative in the uncertainty present within this newer technology as deployed in California. Since PG&E's bundled portfolios are consistent with the Updated 2021 PSP, the same findings hold.

The following information is also provided in Section IV.a.iii of the Action Plan below as requested by the Commission:

Currently, PG&E does not have specific procurement activities for OSW. PG&E is tracking regulatory processes at the state and federal level for potential procurement opportunities.

Significant transmission upgrades are needed to make resource procurement available to LSEs. Given the long-lead time nature and very large capital costs associated with the transmission along with the untested and risky nature of the technology, individual LSEs may choose not to engage in self-procurement of this clean and renewable energy technology. While this has been identified in PG&E's LSE Plan as a selected resource, construction of OSW resources off the California coast will require a broad and coordinated effort by stakeholders and local, state, and federal government agencies to ensure that this clean resource is available to LSEs.

OSW may be a candidate for the CPUC to consider the use of centralized procurement to overcome many of the market barriers, potentially high upfront costs, and timeline risks that are present for this unique technology type.

[62] CEC Staff, Offshore Wind Development off the California Coast (Aug. 2022), pp. 61-62.

n. Transmission Development

PG&E has included detailed resource location information for new contracted resources in the RDTs as required by the Commission. For more information, see the RDT, Unique Contracts tabs, for a list of resources, their queue positions, and other information.

For its 30 MMT Conforming and 25 MMT Conforming Portfolios, PG&E made generic resource additions to meet its 2030 GHG and 2035 emissions benchmarks. These resources do not yet have an interconnection queue position. To ensure that the generic resources are a part of the CPUC Updated 2021 Preferred System Portfolio, PG&E limited the candidate resources available to meet PG&E's open GHG position to those chosen at the system level by the RESOLVE model. Therefore, PG&E's transmission assumptions are consistent with the CPUC Updated 2021 PSP assumptions.

Since the additional resources identified under the "High Electrification Planning" portfolios also rely on the generic resource assumptions in the Updated 2021 Preferred System Portfolio, PG&E did not map those to specific substation/busbar locations.

As noted in the Lessons Learned section, the actual transmission need, and cost will be available after CAISO's reliability assessment in its TPP. Given the level of increase in renewable resources, it is likely that additional transmission investment will be required to interconnect and reliably integrate the new renewables and storage resources to the CAISO system.

IV. Action Plan

The action plan described herein demonstrates PG&E's near-term activities align with its planning and procurement strategy, outlines current and planned activities to address DAC, and notes what actions PG&E is requesting from the Commission to consider to facilitate its effective implementation of its 2022 IRP. PG&E's 2022 IRP Action Plan is highly influenced by PG&E's climate strategy and the plan is on track to meet California's GHG emissions targets. Each subsection of the action plan provides a clear overview of PG&E's progress toward achieving its GHG target compliance and in providing valuable contributions in meeting California's clean energy goals in a safe, reliable, and cost-effective manner.

Based on the study objectives and results of PG&E's IRP analysis, this section presents PG&E's activities to procure the resources identified in its Conforming Portfolios. The Action Plan presented below is the same for both Conforming Portfolios as well as for the ATE alternative portfolio. To meet the goals laid out in its study design section, PG&E anticipates the need for an additional 12 TWh of GHG-free energy by 2030. Given this need, PG&E believes it is prudent to begin soliciting or entering negotiations for resources as soon as possible and is therefore requesting procurement authorization from the CPUC in this filing. The exact quantity and types of resources PG&E will ultimately procure to satisfy its procurement needs may vary depending on the resource mix, changes in load forecast, outcomes of ongoing regulatory proceedings, or procurement resulting from future mandates. Ultimately, PG&E's goal is to procure these incremental resources gradually to mitigate potential risks with future events, developments, and forecast adjustments. More details regarding this procurement authorization request can be found in Section IV.c.i.

a. Proposed Procurement Activities and Potential Barriers

The sections below describe PG&E's supply-side procurement activities (e.g., renewable energy and energy storage) as well as demand-side procurement activities that are not otherwise reflected in the supply-side tables of this report.

i. Resources to meet D.19-11-016 procurement requirements

System Reliability RFOs: In November 2019, the CPUC issued D.19-11-016, which ordered incremental electric system reliability procurement by all LSEs operating within the CAISO's balancing area to meet system RA needs for the period 2021–2023 to address potential system RA shortages beginning in 2021. D.19-11-016 requires PG&E to make incremental procurement of 765.1 MW[63] of system-level qualifying capacity. The Decision also required that at least 50 percent of LSE resource responsibilities come online no later than August 1, 2021, at least 75 percent by August 1, 2022, and the remaining by August 1, 2023. PG&E issued its System Reliability RFO – Phase 1 on February 28, 2020 to solicit offers from participants for the purchase of eligible system RA to come online by August 1, 2021, and count towards PG&E's requirement. At the conclusion of the RFO, PG&E submitted for CPUC approval seven agreements, together totaling 423 MW of incremental system RA.[64] PG&E issued the System Reliability RFO – Phase 2 on July 10, 2020 to procure the remaining required MW. At the conclusion of the Phase 2 RFO, PG&E submitted for CPUC approval six agreements, together totaling 387 MW of incremental system RA.[65]

Information for Procurement Ordered in D.19-11-016 (2019 IRP Procurement Track): In response to the system RA procurement ordered in D.19-11-016, PG&E submitted a Tier 3 Advice Letter (AL) 5826-E on May 18, 2020, seeking Commission approval of seven agreements to meet PG&E's August 1, 2021 requirement (Phase 1) and a Tier 3 AL 6033-E on December 22, 2020, seeking Commission approval of six agreements to meet PG&E's August 1, 2022 and 2023 requirement (Phase 2). The agreements were submitted confidentially to the Commission in PG&E Advice 5826-E and PG&E Advice 6033-E. PG&E has procured 788.21 MW NQC and expected online dates for the projects that PG&E has entered into agreements with to meet its 2021, 2022, and 2023 requirements.

ii. Resources to meet D.21-06-035 procurement requirements

MTR RFOs: On June 30, 2021, the CPUC issued D.21-06-035. In D.21-06-035, the Commission requires incremental procurement of 11,500 MW of additional NQC resources, of which PG&E is responsible for 2,302 MW for its bundled service customer portion. The decision requires that at least 2,000 MW be online by August 1, 2023, an additional 6,000 MW by June 1, 2024, an additional 1,500 MW by June 1, 2025, and an additional 2,000 MW by June 1, 2026. Further, D.21-06-035 requires that at least 2,500 MW of resources procured collectively by the LSEs, between 2023 and 2025, be either zero emission generation resources, generation resources paired with storage, or demand response, to replace the current supply of energy from the

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[63] PG&E was informed on April 15, 2020 via ALJ Ruling that it is required to procure an additional 48.2 MW for CCAs and ESPs in its TAC area that chose not to self-provide their required portion of incremental system RA. 765.1 MW includes the original 716.9 MW for PG&E bundled customers plus an additional 48.2 MW of backstop procurement. *ALJ's Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual 2020 Integrated Resource Plan Filings and Assigning Procurement Obligations Pursuant to Decision 19-11*-016 (Apr. 15, 2020) R.16-02-007, p 9.

[64] See PG&E AL 5826-E, dated May 18, 2020.

[65] See PG&E AL 6033-E, dated December 22, 2020.

Diablo Canyon Power Plant (DCPP). This is to ensure there are no GHG emissions increases upon DCPP's retirement.

PG&E issued its MTR RFO – Phase 1 on June 18, 2021, to solicit offers to procure incremental NQC resources with an expected online date of August 1, 2023, and June 1, 2024, which will count towards PG&E's procurement requirement of a total of 1,601 MW by June 1, 2024. At the conclusion of the RFO, PG&E submitted for CPUC approval, Tier 3 AL 6477-E on January 21, 2022, nine agreements totaling 1,598.7 MW.

PG&E issued its MTR RFO – Phase 2 on April 15, 2022, to solicit offers to procure incremental NQC resources to provide system-level qualifying NQC with online dates beginning June 1, 2024 through June 1, 2026 depending on the category. All resources will be expected to be considered incremental in counting towards PG&E's procurement responsibilities, as specified in the Decision.

iii. Offshore Wind

The following information is also provided in Section III.m of the Action Plan below as requested by the Commission:

Currently, PG&E does not have specific procurement activities for OSW. PG&E is tracking regulatory processes at the state and federal level for potential procurement opportunities.

Significant transmission upgrades are needed to make resource procurement available to LSEs. Given the long-lead time nature and very large capital costs associated with the transmission along with the untested and risky nature of the technology, individual LSEs may choose not to engage in self-procurement of this clean and renewable energy technology. While this has been identified in PG&E's LSE Plan as a selected resource, construction of OSW resources off the California coast will require a broad and coordinated effort by stakeholders and local, state, and federal government agencies to ensure that this clean resource is available to LSEs.

OSW may be a candidate for the CPUC to consider the use of centralized procurement to overcome many of the market barriers, potentially high upfront costs, and timeline risks that are present for this unique technology type.

iv. Out-of-State Wind

The following information is also provided in Section III.l of the Action Plan below as requested by the Commission:

PG&E does not have specific procurement activities for out-of-state (OOS) wind, though it continues to monitor the regulatory processes, including the CAISO consideration of transmission to connect OOS wind areas to California, and the commercial prospects for wind technologies to be incorporated into PG&E's portfolio.

Generally, PG&E supports California accessing OOS wind as an option to meet its clean energy goals while ensuring system reliability and customer affordability, and PG&E itself is interested in investigating procurement of OOS wind to meet its own clean energy goals. However, PG&E believes that CAISO stakeholders (and particularly LSEs) need additional information on the status of OOS wind project development in the various states in the WECC and cost-effectiveness information on the various potential transmission lines that could bring OOS wind into California to assess which line would be most cost-effective for CAISO to commit to and put into its rate base.

v. Other Renewable Energy

This section includes PG&E procurement activities (including near-term actions), potential barriers, and resource viability for renewable resources in PG&E Conforming portfolios (Tables 7 and 8).

PG&E will continue to meet its RPS requirements as established by the California Legislature. As shown in its Draft 2022 RPS Plan[66], PG&E projected an RPS need before 2030. Although this need is several years away PG&E requested authority to procure resources to meet this need with solicitations beginning in 2023 to help (1) hedge against changes to PG&E's need year and (2) provide PG&E the ability to procure in a supply constrained market. The 12 TWh procurement request in this IRP filing is inclusive of the RPS procurement request made earlier this year in its RPS plan but provides additional detail on the volume and reflects other planning and legislative procurement drivers that also reflect PG&E's IRP goals compared to the RPS plan request. Table 23 below provides a summary of PG&E's renewable energy actions, barriers, and recommendations.

[66] See PG&E's Draft 2022 RPS Plan (July 1, 2022) R.18-07-003, Section VIII, Renewable Net Short (RNS) Calculation, for more details on PG&E's RNS position, http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=709459 (as of Oct. 26, 2022).

TABLE 23
RENEWABLE ENERGY – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• Administer BioMAT program auctions. • Administer ReMAT program.[(b)] • Bioenergy Renewable Action Mechanism (BioRAM) procurement. • Administer AB 1613 program. • DAC solicitations twice a year. • GTSR solicitations twice a year. • Administer Public Utility Regulatory Policies Act (PURPA) procurement. • Continue allocations and sales of RPS energy.
Key Barriers	• Load forecast uncertainty, including new electrification load and load migration. • Delays in achieving expected online dates.
Proposed New Near-Term Actions/ Commission Direction	• PG&E has submitted a request for renewable energy procurement in its Draft 2022 RPS Plan.
Deviations From Current Resource Plans	No deviations.
Recommendation for Future IRPs	The CPUC continue to model RPS resources as candidate resources.

(a) Resource additions are from either existing contracts not yet online or future procurement for mandated procurement programs. This total RPS generation value includes an assumption of continued RPS bundled energy sales.

(b) PG&E suspended the ReMAT program in 2017 as directed by the CPUC in response to a federal court order in *Winding Creek Solar LLC v. Peevey*. On June 26, 2020, the CPUC issued a staff proposal with proposed modifications to bring ReMAT into compliance and subsequently reopen the program. On October 16, 2020, the CPUC issued its final decision 20-10-005 to bring the ReMAT program into compliance. PG&E reopened its ReMAT program on Feb 5, 2021.

Existing Near-Term Actions

PG&E is also administering the following programs which impact RPS procurement:

Administer BioMAT Program Auctions: PG&E will continue to administer its bi-monthly BioMAT auctions for waste management and dairy/agricultural projects, and monthly BioMAT auctions for sustainable forest management projects. On October 3, 2018, the CPUC issued a staff proposal, initiating a BioMAT program review. On September 1, 2020, the CPUC issued its final decision 20-08-043, extending the program end date to December 31, 2025 among other program changes. Through BioMAT, PG&E is required to procure a total 111 MW of bioenergy resources. Currently PG&E has procured 38 MW under this program.

Administer ReMAT Program: PG&E will continue to administer its ReMAT program for renewable peaking, non-peaking, and baseload resources. On December 17, 2021, the CPUC issued D.21-12-032, resolving several outstanding petitions for modification. Among other program changes, the decision allows renewable facilities enhanced with storage to participate and revises the program end date to when remaining capacity in the program reaches 0.99 MW or less. Through ReMAT, PG&E is required to procure a total of 218.8 MW of renewable resources. Currently PG&E has procured 102 MW, which includes capacity procured under the predecessor programs E-SRG and E-PWF.

BioRAM Procurement: PG&E will continue to comply with SB 901 and CPUC Res.E-4977 which requires PG&E to seek to extend various Biomass contracts by five years and modify feedstock requirements. PG&E has so far received CPUC approval for one amendment to an existing BioRAM contract and one new 5-year BioRAM contract. PG&E will offer the RA and RECs generated by BioRAM facilities for sale in accordance with the Tree Mortality Non-Bypassable Charge decision. SB 1109 requires the IOU procure their share of 125 MW of existing bioenergy generating capacity by 12/31/2023. The contracts terms must be 5-15 years. Also, IOUs must seek offer to extend existing BioRAM contracts that expire before December 31, 2028 5-year extensions.

Administer AB 1613 Program: In compliance with D.09-12-042, the AB 1613 contract remains available for efficient CHP facilities.

DAC Solicitations: In compliance with E-4999, PG&E will hold two solicitations per year seeking new solar PV projects for Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff ("CS-GT") until the remaining capacity is procured. PG&E's allocation is 54.82 MW for DAC-GT and 14.20 MW for CS-GT. PG&E has procured the full allocation for the DAC-GT program, and the program has closed. There remains 2.2 MW of procurement need for the CS-GT program, which had a new solicitation issued on September 6, 2022.

GTSR Solicitations: In compliance with D.21-12-036, PG&E will hold a minimum of two solicitations per 12-month period for both the Green Tariff program (brand name Solar Choice) and for the Enhanced Community Renewables (brand name Regional Renewable Choice) program until enrolled capacity is met by new dedicated sources. PG&E is allocated a total of 272 MW to procure under Green Tariff Shared Renewables ("GTSR"). GTSR has two program components, and PG&E has procured about 53 MW under Solar Choice and 3.65 MW under Enhanced Community Renewables.

PURPA In compliance with D.20-05-006, the Standard Offer PURPA contract remains available to Qualifying Facilities.

Continue Sales of Bundled RPS Volumes as Needed: Pursuant to the Commission's approval of PG&E's 2022 RPS Procurement Plan, PG&E continues to consider opportunities for sales of RPS volumes that benefit its bundled customers as needed. Execution volumes are dependent on a combination of factors, including limits under PG&E's pre-approved RPS sales framework, market demand and market pricing as well as any impacts D.21.05-030 implementation may have on PG&E's portfolio.

Key Barriers

Load forecast uncertainty, including new electrification load and load migration: PG&E's RPS need is a function of its forecasted bundled service retail sales. The energy landscape in California has changed significantly over the last few years and an emphasis on customer choice, in the form of DG, CCAs and potential further reopening of DA, has dramatically changed PG&E's expectation of future retail sales. Uncertainty regarding future levels of load departure to other suppliers, as well as load growth from EV adoption, creates uncertainty with respect to PG&E's future RPS need.

Delays in achieving expected online dates: Force Majeure and other development delays, such as interconnection and deliverability upgrades, can cause delays in achieving expected online dates.

vi. Other Energy Storage

This section includes PG&E procurement activities (including near-term actions), and potential barriers for energy storage resources in PG&E's Conforming Portfolios (see Tables 7 and 8), in this report. As discussed above, PG&E will continue to procure storage resources for MTR and IRP targets.

PG&E is actively implementing California's programs to develop cost effective energy storage resources in the state to integrate renewable resources, provide output in periods of peak demand, and reduce GHG emissions. Additionally, in some cases energy storage projects can be a preferred alternative to provide grid efficiency and reliability in lieu of conventional wires solutions. Energy storage technology can also provide enhanced grid resiliency for critical customers during grid disturbances. PG&E's energy storage strategy includes all of these use cases and seeks to ensure the proper regulatory rules are in place to enable them.

PG&E is accelerating deployment of energy storage on its grid through owning and operating storage resources, procuring storage through third party contracts, testing innovative storage solutions through pilot projects, and enabling customer adoption of energy storage. PG&E

envisions a large and growing need for energy storage in the future as California continues to increase renewable energy production and pursue increasingly ambitious GHG reduction goals. There is a suite of innovative storage technologies, including power to gas, pumped hydro, and compressed air, that PG&E feels should be considered "eligible storage technologies" to meet the state's needs. In summary, there is ample opportunity going forward for utilities, third-party storage providers, and retail customers to be part of the energy storage solution that incorporates a wide array of storage technologies. Table 24 below provides a summary of PG&E's energy storage actions, barriers, and recommendations.

TABLE 24
ENERGY STORAGE – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• Mid-Term Reliability (MTR) RFOs
Key Barriers	• Cost effectiveness of storage vs. traditional grid solutions. • Lack of enhanced visibility, monitoring, and control systems for utility operations to ensure grid needs are addressed and fully realize the value of energy storage. • Cross-sector competition for current energy storage technologies creates upward pressure on prices.
Proposed New Near-Term Actions/ Commission Direction	None at this time.
Deviations From Current Resource Plans	No deviations.
Recommendation for Future IRPs	Continue modeling energy storage resources as candidate resources.

Existing Near-Term Actions

AB 2514 Energy Storage Targets: PG&E is on track to comply with the state-wide energy storage adoption requirements of 580 MW by 2024 (AB 2514) and has largely met its requirements in all three domains (transmission, distribution, and customer).

AB 2868 Distributed Energy Storage Investments and Programs: In March 2018, PG&E filed its proposal with the CPUC to deploy distributed energy storage in compliance with AB 2868.[67] PG&E included in its proposal up to 5 MW BTM thermal energy storage program which provides incentives for low-income customers and customers in DACs to electrify their water heating and shift the associated load to off-peak hours. PG&E's pilot program – "WatterSaver" – launched in March 2022 and is expected to enroll 5,000-9,000 customers, who will benefit from energy bill savings and reduced onsite emissions from propane-based water heating.

Key Barriers

Cost effectiveness of storage vs. traditional grid solutions: While battery costs are expected to decline over time, energy storage is still an expensive technology when compared to traditional grid infrastructure or generation today. In some cases, energy storage is precluded as a solution to grid needs due to PG&E's obligation to seek the most cost-effective grid solutions for its customers.

Lack of enhanced visibility, monitoring, and control systems for utility operations to ensure grid needs are addressed and fully realize the value of energy storage: As storage deployment and opportunities for multiple use applications increase, the complexity of utility distribution and transmission grid planning and operations will also increase. Enhanced utility planning, operational and communication systems and protocols will be required to: (1) maintain both transmission and distribution grid safety and reliability; (2) realize the maximum value of storage; and (3) validate storage operational performance for compliance and settlements. These enhanced measures will require integration of multiple transmission and distribution system planner and operator applications to not only validate storage performance but to also simplify management of the grid.

Cross-sector competition for current energy storage technologies creates upward pressure on prices: Lithium-ion-based storage, the generation sector has to compete with the electric vehicle sector and may not have the economies of scale to be competitive with Battery Energy Storage System vendors without paying high premiums. Energy storage emerging technologies that can meet 4-hour or 8-hour needs without lithium have considerable technology risk that is still in research, development, and deployment stages though may soon achieve broader economies of scale.

[67] A.18-03-001, Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018.

vii. Other Demand Response

PG&E continues to support DR as a technology-neutral platform through which customers and aggregators can access markets and receive compensation for the provision of grid services. Moreover, PG&E continues to operate its own DR programs as well as support third-party DR market participation. PG&E facilitates third-party provider participation that directly bid into the CAISO markets with access to customer authorized data for CAISO registration, verification of customer eligibility, and settlement processes for such a mechanism.[68]

PG&E is currently in the final year of its current funding cycle for DR programs (2018–2022)[69] and submitted A.22-05-002 to the Commission in May 2022 with its proposals for the 2023 Bridge Year and next funding cycle (2024-2027).[70] Since submitting its most recent IRP Action Plan, the Commission opened the Emergency Reliability OIR (R.20-11-003) to identify and execute all actions necessary to ensure reliable electric service following rotating outages that occurred in August 2020 due to an extreme heat storm. In this proceeding, the Commission authorized new demand response pilots that PG&E launched in 2021, such as the Emergency Load Reduction Program (ELRP) and Bring-Your-Own Thermostat (BYOT) Pilot.

In addition, the following ongoing trends and issues will continue to shape the delivery of PG&E's DR portfolio in the coming years:

The role of third-party participation. The CPUC is still evaluating the future of DRAM, as the provider of economic DR.

CCA DR program impact on IOU programs: Per the Competitive Neutrality[71] framework, if a CCA offers a "similar" program as an IOU, the IOU program must cease to offer its own DR program to customers of that CCA, and remaining programs funds would need to be returned.

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[68] This includes the Rule 24 tariff and the ongoing DRAM pilot.

[69] D.17-12-003 adopted each of the three IOUs Funding Applications for 2018-2022. As part of the extended cycle, each IOU was obligated to file a Mid-Cycle update by April 1, 2020 (AL-5799-E). Furthermore, the IOUs were ordered to file their next five (2023-2027) year funding Applications by November 1, 2021.

[70] PG&E's Application includes 2023 as a bridge year between the prior cycle (2018-2022) and (2024-2027). The Commission is currently prioritizing approval of DR programs for the 2023 Bridge Year before the end of 2022 in Phase I of the DR proceeding.

[71] D.14-12-024 established a competitive neutrality cost causation framework by which IOUs would refrain from offering DR products and services to customers of third-party Load Serving Entities (LSEs), such as CCAs or ESPs, if these LSEs establish a "similar" DR program. Moreover, DR funds collected from customers who are with CCAs and ESPs that offer a "similar" DR program would need to be returned; thereby, reducing the pool of funds available to support the IOU DR program. The Commission approved the Joint IOU's implementation filing (AL 5353-E) in July 2022 via Res.E-5008.

The capacity valuation of demand response. The RA Proceeding at the CPUC has ushered in new proposals from CAISO on the value of DR. The final capacity valuation of DR could be a large sensitivity in the size of the portfolio and impact cost-effectiveness. Generally, DR programs should be cost-effective.

Prohibited Resources: The restrictions on the use of fossil fueled backup generation have created some challenges, especially for traditional load drop DR resources.[72]

The technology that participates in demand response. The underlying load impacts both the size of the portfolio and its performance in the CAISO market. While most of the load that participates in DR is behavioral, market trends indicate that we may see more automated and dispatchable load in the future.

A policy shift away from market integration to load management: PG&E recognizes there has been a waning interest in CAISO market participation due to challenges that are unique to demand response, coupled with an increased interest in more flexible rates, as suggested by the CEC in their Load Management Rulemaking.[73]

Increased Interest in and Potential for Load Shifting: Technological advances and the increase in potentially flexible demand due to electrification (e.g., EV charging) presents an opportunity for increased deployment of demand shifting to play a greater role as part of DR portfolios and a more holistic load management portfolio. California SB 846 recognizes this growing potential and requires the CEC, in consultation with the CPUC and CAISO, to adopt load shifting goals with targets as part of the biennial IEPR process and to recommend policies to increase load shifting opportunities that support GHG reduction and affordability goals. PG&E looks forward to collaborating with agencies on expanding the role of load shifting programs going forward.

Table 25 below provides a summary of PG&E's demand response actions, barriers, and recommendations.

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[72] CPUC Res.E-4906 imposed restrictions on the use of prohibited resources for supporting DR events beginning January 1, 2019. The proceeding addressing this issue undertook a test year pilot to determine the level of baseline compliance and to test metering/logging capabilities for enforcement. In July 2022, the Commission re-opened the record of the proceeding to request comments on the 2020 and 2021 Demand Response Prohibited Verification Audits. A Commission decision is expected in 2022.

[73] The CEC initiated a stakeholder process to address load management. The *2020 Load Management Rulemaking* (Docket #19-OIR-01) expands on efforts to increase efficiency and demand flexibility in California's electricity grid. The CEC will revise the existing standards to promote a demand flexible electricity market, while ensuring that costs and benefits are equitable. The CEC will consider new tariffs, technologies, and other measures that are consistent with the need for increased demand flexibility to support a renewable and decarbonized electricity grid. <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-OIR-01> (as of Oct. 26, 2022)

TABLE 25
DEMAND RESPONSE – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• Work with regulators on programs that can participate in CAISO and CPUC DR markets. • Continue PG&E's DR programs and pilots for residential and non-residential customers. • Continue refining the DRAM pilot with third party demand response providers.
Key Barriers	• Uncertainty with respect to PG&E's role as the demand response provider (DRP) or procurer. • Uncertainty with respect to the ability of DR resources to cost-effectively provide grid services. • Enrolling EV and other BTM battery storage in demand response programs for smart charging. • Rapid technological advancement and changing customer preferences.
Proposed New Near-Term Actions / Commission Direction	• Approval of PG&E's 2023 Bridge Year Application. • Consideration of PG&E's proposals in its 2024-2027 Application.
Deviations From Current Resource Plans	PG&E's DR portfolio is aligned with the current DR funding cycle budget (2018–2022) authorization per D.17-12-003.
Recommendation for Future IRPs	• Continue to evaluate DR in IRP as a candidate resource.

Existing Near-Term Actions

Offer DR Programs for Residential and Non-Residential Customers: PG&E's DR portfolio currently consists of programs authorized in D.17-12-003 for the 2018-2022 program cycle as well as new pilots adopted in the Emergency Reliability OIR. The programs authorized in D.17-12-003 include the Base Interruptible Program (BIP) and Peak Day Pricing (PDP) for non-residential customers, SmartAC and Smart Rate for residential customers, and Capacity Bidding Program (CBP) and time-of-use (TOU) rates for all customer classes. Customers can enroll in PG&E DR programs directly or through third-party aggregators (e.g., CBP and BIP). In addition, the Commission authorized new demand response pilots in R.20-11-003 that PG&E launched in 2021, such as the ELRP and BYOT Pilot.

In the near-term, PG&E proposed modifications to CBP and its Rule 24 program for the 2023 Bridge Year. PG&E's proposed CBP changes include:

- Changes to the program hours to align CBP availability with the hours of greatest potential for supply shortfalls;
- Increasing incentives to encourage greater participation;
- Enhance the settlement process for CAISO wholesale energy payments; and
- Continue electronic enrollments in the program.

In addition, PG&E proposes to increase funding for its Rule 24 program, which enables third-party demand response providers to enroll PG&E's electric retail customers in the CAISO wholesale electric market, based on forecasted mass market participation levels.

Pilot the DRAM RFO with Third Party Demand Response Providers: PG&E is administering the DRAM RFO pilot through a pay-as-bid auction of monthly capacity for DR RA bid into the CAISO's energy market, where DR providers must meet the CAISO's must-offer obligations with customers in PG&E's service area. The pilot is designed to encourage third party DR providers to develop demand response programs that can spur innovation and growth of a competitive third-party market. The Commission is currently assessing the future of DRAM as part of PG&E's 2023-2027 DR Application.

Key Barriers

Uncertainty with respect to PG&E's role as the demand response provider (DRP) or procurer: This uncertainty manifests in in two ways. First, CCAs are serving an ever-increasing portion of customers within the PG&E service territory. Second, the future of the role of IOUs in providing DR versus third parties, such as DRAM, is an open question.

With respect to the first issue, under the Competitive Neutrality Cost Causation principle, a customer whose energy is procured by a CCA or an ESP is ineligible to participate in an IOU DR program if the CCA or ESP offers a program that is deemed by the Commission to be "similar" to the one offered by the IOU.[74] In addition, the Commission adopted Resolution E-5008 in July 2022, which established a process for the IOUs to implement a bill credit to CCA or ESP customers participating in a similar DR program. It remains to be seen how these processes may impact enrollment levels and cost effectiveness of IOU DR programs.

Uncertainty with respect to the ability of DR resources to cost effectively provide grid services: Additionally, grid needs are evolving away from system capacity and toward local capacity, flexible capacity, and ancillary services that are needed to support the transition to a cleaner grid. It will be important to determine which evolving grid needs DR is best suited to meet cost-effectively. This is important because the IOU DR programs are mandated to be cost-effective, and the complexities associated with an evolving grid may require costly solutions in terms of program offerings and system administration. In addition, recent changes to the methodology for calculating Avoided Costs could impact the value attributed to DR resources.[75]

Enrolling EV and other BTM battery storage in demand response programs for smart charging: Many BTM DER technologies have the potential to provide grid services via DR by temporarily dropping or shifting load to help realign supply and demand, and/or reduce the customer's utility bill. These include battery systems, in EVs or stand alone. Smart charging of a battery can be utilized to maximize customer benefit, which may or may not align with maximizing benefit to the electric grid. If enrolled in a DR program, however, the battery is incentivized to dispatch when needed by the grid.

Rapid technological advancement and changing customer preferences: An important recognition in DR program design involves consideration of technological advancement and customer preferences. These are critical as certain legacy technologies (e.g., direct load control) may no longer provide cost-effective resources. Moreover, customers' desire to embrace new technologies (e.g., Smart thermostats) and understanding behavioral changes (e.g., when are customer using resources) are critical in the development of DR offerings. A key challenge is staying ahead of these trends.

viii. Other Energy Efficiency

PG&E is optimizing its EE portfolio for recent CPUC direction that emphasizes EE's full-lifecycle benefits to the grid, as well as longer-term and equity objectives EE programs serve, while in 2022 continuing the transition started in 2018 toward a predominantly third-party implemented portfolio. In February 2022, PG&E filed an application for approval of its 2024-2031 strategic business plan. The business plan reflects a focus on offering a diverse portfolio to maximize participation and grid benefits, supporting a multi-pronged approach to

[74] D.14-12-024, p. 87, OP 8b.

[75] Resolution E-5228, 2022 Policy Updates to the Avoided Cost Calculator.

building decarbonization, and incorporating support for load management and customer resiliency into programs.

PG&E's 2024-2031 EE Strategic Business Plan presents PG&E's annual Total System Benefit (TSB), energy savings, CO_2 emissions reduction, and cost effectiveness forecasts for 2024-2027, as well as a budget cap request for 2024-2031. The plan also discusses strategies that PG&E will employ in its 2024-2027 portfolio. These include:

- Delivering TSB by offering programs and services at multiple interaction points, and deploying a variety of program types, intervention approaches, and transaction structures to increase customer participation and generate benefits across customer sectors and PG&E's territory.
- Undertaking a multi-pronged approach to decarbonization by supporting all-electric and electric-ready buildings, including all-electric new construction. Where possible, PG&E will prioritize zonal electrification, followed by whole-building electrification, and targeted electrification for harder-to-electrify technologies and customer sectors. PG&E will also leverage technical support and advocacy through codes and standards, and workforce education & training.
- Supporting load management and customer resiliency by providing permanent load reduction, incorporating EE measures with flexible demand capabilities, and using EE to support or reduce customer costs for resiliency solutions.

The Strategic Business Plan also reflects the impact of several recent policy developments in the energy efficiency space.

In May 2021, the CPUC issued D.21-05-031, which put in place a new performance metric, Total System Benefit (TSB), for ratepayer-funded EE portfolios in California beginning in 2024. TSB is defined as "the sum of the benefit that a measure provides to the electric and natural gas systems."[76] TSB is an expression, in dollars, of the lifecycle energy, ancillary services, generation capacity, T&D capacity, and GHG benefits of energy efficiency activities, on an annual basis. The TSB metric replaces energy and peak demand savings as the goals metric for ratepayer-funded EE programs. The shift to the TSB metric will recognize the impact of longer-life EE measures over the full time they are installed and saving energy. It also assigns greater value to load reduction that occurs at times that align with system needs. The TSB metric is fuel agnostic and thus may more easily facilitate fuel substitution.

Beginning in 2022, D.21-05-031 also ordered EE Program Administrators (PA) to "segment" the voluntary, or non-codes and standards, portion of their EE portfolios into three categories, based on their primary purpose: resource acquisition, market support, and equity. Cost-effectiveness requirements for IOUs were changed and now apply only to the resource

[76] CPUC, Total System Benefit Technical Guidance, Version 1.2 (Oct. 25, 2021) p. 1.

acquisition segment of PA voluntary (non-codes and standards) program portfolios.[77] The resource acquisition segment comprises the majority of IOUs' portfolio budgets, at least 70 percent. This change in cost-effectiveness policy may have the impact of helping EE PAs focus their efforts on delivering cost-effective TSB across the resource acquisition segment, while focusing on other objectives in the market support and equity segments.

While segments are intended to indicate programs' primary purpose and only the resource acquisition segment remains subject to cost-effectiveness compliance considerations, programs in any segment may deliver TSB and contribute toward EE PAs' achievement of their TSB goals, and programs in the resource acquisition segment may serve hard-to-reach, DAC, or underserved customers. PG&E completed its initial segmentation of its portfolio in its 2022-2023 Biennial Budget AL and discusses portfolio segmentation in depth in its 2024-2031 Strategic Business Plan Application.[78]

Prior CPUC direction on third-party outsourcing remains in effect, and PG&E has fully embraced the transition to a predominantly third-party implemented portfolio. PG&E met the June 30, 2020 compliance target of 25 percent third-party programs and the December 31, 2020 compliance target of 40 percent by the end of 2021. PG&E is on track to meet the CPUC's final third-party outsourcing target of 60 percent by December 31, 2022. With the phase-in of third-party implementation shifting the task of program design and delivery more to third parties, PG&E retains responsibility to ensure that the contracted programs remain consistent with PG&E's approved strategies to achieve reliable energy savings and total system benefit.

In the near term, PG&E is also focused on accommodating the shift toward statewide EE programs.[79] PG&E leads the statewide new construction, codes & standards advocacy, workforce education & training, and institutional partnerships programs with the State of California and state Department of Corrections. Statewide programs led by other IOUs include

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[77] D.21-05-031, p. 14 and p. 81, OP 2. Segmentation applies only to the voluntary (non-codes and standards) portion of IOUs' program portfolios. Resource acquisition programs are those aimed primarily at delivering cost-effective, near-term TSB, and make up at least 70% of IOUs' EE voluntary program portfolios. This portfolio segment must meet at 1.0 TRC test. Market support programs are aimed primarily at supporting the long-term success of the EE market (for example, by educating customers or training contractors). Equity programs are aimed primarily at serving hard-to-reach or underserved customers and disadvantaged communities in advancement of the CPUC's ESJ action plan. Together, the market support and equity segments are limited to no more than 30 percent of Pas' voluntary portfolios, and they are not subject to cost-effectiveness requirements. Performance metrics for the market support and equity segments are under discussion as of September 2022. Codes and standards programs remain classified separately.

[78] See A.22-02-005, PG&E's Prepared Testimony, Exhibit 2, Chapter 3.

[79] In D.18-05-041, the Commission ordered a move to statewide administration of certain programs, in which a single IOU leads the program operationally for the entire state.

technology programs such as lighting, plug load and appliance, food service, and water heating. Because these programs operate and serve customers throughout the state, program impacts (savings or TSB) are credited to participating IOUs proportionally.

Finally, as federal and state investment in energy efficiency and decarbonization increase, PG&E expects to administer programs designed to complement efficiency and electrification support available through external funding sources. For example, as low-to-moderate-income and whole-building electrification program authorized in the Inflation Reduction Act (IRA) become available in California, PG&E anticipates working with its third-party implementers and partners to help their program designs evolve to complement IRA programs.

Table 26 below provides a summary of PG&E's energy efficiency actions, barriers, and recommendations.

TABLE 26
ENERGY EFFICIENCY – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• PG&E expects to achieve its final, 60% outsourcing target by December 31, 2022. • PG&E filed its 2024-2031 EE Strategic Business Plan Application on February 15, 2022, and expects a decision in Q3 2023.
Key Barriers	None at this time.
Proposed New Near-Term Actions / Commission Direction	• Commission should approve PG&E's 2024-2031 EE Strategic Business Plan.
Deviations From Current Resource Plans	None at this time.
Recommendation for Future IRPs	• Evaluate EE in IRP as a candidate resource.

ix. Other Distributed Generation

Here, distributed generation (DG) refers to customer-sited renewable generation installations – primarily rooftop solar PV systems and, increasingly, rooftop solar PV systems paired with storage. PG&E has a long history as the leading utility when it comes to solar DG integration.[80] PG&E supports customer adoption of solar and other DG technologies by implementing DG-specific tariffs and incentive programs, working to improve and streamline interconnection processes, and by providing customers DG-related educational and customer service resources.

[80] Smart Electric Power Institute (SEPA) 2019 Top 10 Winners, <https://sepapower.org/2019-top-10-winners/> (as of Oct. 26, 2022).

PG&E has also been active in developing best practices for incorporating DG into load planning and building codes and standards.

PG&E recently reached 655,000 bundled and unbundled customer service agreements with DG installed behind the utility meter. PG&E is supporting these and future DG customers through several actions.

Table 27 below provides a summary of PG&E's distributed generation actions, barriers, and recommendations.

TABLE 27
DISTRIBUTED GENERATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• Provide customer service infrastructure to implement Net Energy Metering (NEM) tariffs. • Administer or support DG and storage programs. • Streamline interconnection and facilitate incorporation of solar inverter technology.
Key Barriers	• Incentives through the NEM tariff structure that are misaligned with DG's net value. • Lack of visibility into DG generation data. • Inability to use available technology to capture additional value and minimize operational impacts at high penetration levels.
Proposed New Near-Term Actions / Commission Direction	• The new NEM tariff structure should be reformed to correct the inequities created by the existing NEM tariff while incentivizing customer generation and storage technologies in a way that better aligns the interests of all customers and the grid.
Proposed New Near-Term Actions	• Actively continue to participate in ongoing CPUC NEM Reform proceeding to support sustainable customer-focused NEM tariffs.
Recommendation for Future IRPs	• Evaluate DG in IRP as a candidate resource. • Ensure consistent valuation between supply-side resources and DG. • Validate assumed DG generation profiles against metered data.

Provide Customer Service Infrastructure to Implement Net Energy Metering (NEM) Tariffs: NEM tariffs—which allow customers to receive monetary credits for electricity exported to the grid and use credits to offset charges for imported electricity—have spurred significant growth in DG adoption. The NEM tariffs and sub-schedules require specialized billing infrastructure to implement, dedicated staff with specialized training in safe generation interconnection, as well as educational and communication resources for customers and vendors due to the complexity of these tariffs. PG&E provides dedicated staff and billing infrastructure, as well as communications resources (including a call center dedicated to handling approximately 30,000 monthly calls from DG customers) to implement the NEM tariffs and sub-schedules. In addition to the call center, PG&E offers online educational tools and guides for customers who are considering or who have installed DG.

Administer or Support DG and Storage Programs: PG&E manages or supports DG Programs that will continue to facilitate the incorporation of DG and BTM storage into PG&E's electric system. These include:

- The Self Generation Incentive Program (SGIP) is administered by PG&E in its service area, which provides incentives to non-solar PV technologies such as fuel cells and wind, along with storage technologies. In 2020 SGIP was re-oriented to focus on providing customer resilience, and the program currently will extend through 2025. PG&E has paid over 3,600 applications worth over $134M for the Equity Resiliency budget.
- The Multifamily Affordable Solar Housing (MASH) Program is administered by PG&E in its service area. This program is not currently accepting applications and will fund PV installations through the end of 2022.
- The Disadvantaged Communities Single-Family Affordable Solar Homes (DAC-SASH) program is administered by Grid Alternatives on behalf of all three IOU. PG&E supports the DAC-SASH program by reviewing final incentive packages, providing data, and processing payments.
- The Solar on Multifamily Affordable Housing (SOMAH) program is administered by the Center for Sustainable Energy for California. PG&E supports the SOMAH program by providing participant data to the administrator, reviewing final incentive packages, and processing payments. In addition, PG&E ensures safe interconnection of SOMAH PV generation and administers the supporting SOMAH tariff.
- PG&E also administers four community solar programs for both general market and DAC. These programs do not result in rooftop solar installations, instead PG&E procures wholesale resources on behalf of participants; hence they are not included in the DG forecast. For general market these include the Solar Choice and Regional Renewable Choice programs, which are collectively capped at 272 MW of generation resources. For DACs these include the Green Saver and Local Green Saver programs, which are capped at 52.7 and 14.2 MW of solar resources, respectively.

Ongoing Interconnection Streamlining & Transparency Efforts, Accommodation of Storage/EVs, and Planning for a Grid with Higher DER: As phase 1 of an ongoing interconnection (Rule 21) proceeding and associated working groups draws to a close, PG&E has continues to make significant strides in reducing interconnection times, increasing interconnection status transparency, and provide greater ways to adapt to a grid that needs to be able to accommodate more generation/DER notably storage including EV (as storage e.g. vehicle-to-grid (V2G)). To meet these goals, PG&E has consolidated various online interconnection application portals into a single portal and significantly enhanced its portal functionality, incorporated standard interconnection timeline reporting, worked to implementing more advanced smart inverter communications to enable the more sophisticated and adaptive use of smart inverters, established pilots for non-export storage and for EV storage, as well as adopted various consumer protection measures. Looking ahead, PG&E is taking steps to implement generator aggregation arrangements and in phase 2 of the proceeding is beginning to explore various interconnection cost sharing options.

Continue to Integrate DG into Load Planning and Building Codes and Standards: PG&E plans to continue to work with the CEC, CPUC, DG providers, and other stakeholders to improve understanding of DG adoption trends and load impacts, and to assess and implement best practices for incorporating DG into load planning and codes and standards. In addition, PG&E will work with the CPUC and other stakeholders to more closely align the NEM tariff with appropriate cost causation principles.

Advocate for NEM Reform: While PG&E supports the options for its customers to install rooftop solar, particularly when paired with storage, PG&E notes that the current prevailing mechanism for compensating rooftop solar systems – NEM – is in direct conflict with affordability and equity goals. Specifically, the subsidies paid to new customers taking service on the NEM rate exceed any other state except for Hawaii. In fact, within California subsidies paid by PG&E customers exceed those paid by customers of any other utility except for San Diego Gas & Electric. An assessment commissioned by the CPUC of the current NEM tariff demonstrated that this subsidy is regressive: it primarily benefits higher income households at the expense of lower income households including renters.[81] Consistent with PG&E's objective of developing a cost-effective portfolio of resources to ensure customer affordability and support state electrification goals, PG&E has proposed reforms to the NEM tariff that would align compensation for distributed energy resources with their value to all customers and would incentivize customers to install rooftop paired with storage.

[81] Verdant Associates, LLC, Net-Energy Metering 2.0 Lookback Study (Jan. 21, 2021), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nem-evaluation/nem-2_lookback_study.pdf> (as of (Oct. 26, 2022).

Key Barriers

Incentives through the NEM tariff structure that are misaligned with DG's net value: PG&E supports customers' choice to use DG to serve their energy needs, and NEM tariffs have played a role in incenting customers to adopt DG. As was documented in PG&E's communication to the CPUC and other stakeholders during the NEM Successor Tariff proceeding, PG&E remains very concerned that NEM currently provides incentives that are not proportionate to the net value of DG resources to the electrical system,[82] as is required by law.[83] This has resulted in DG adoption that is inconsistent with meeting system needs in the least cost manner, as demonstrated in RESOLVE modeling that shows that overall system costs increase with higher assumed levels of BTM PV adoption. Furthermore, under the past and current NEM Tariff structures, revenue recovery from the DG customers usually is less than the cost to serve them, and the DG customers cost the utility more to serve in comparison to the non-NEM customers under most of the circumstances. As a result, there is a disproportionate burden on customers who cannot, or choose not to, adopt DG to bear the cost for electric system infrastructure that supports all customers.

PG&E supports continued availability of rooftop solar as a viable option for its customers and looks forward to working with all stakeholders in near-term CPUC proceeding expected to result in a sustainable NEM tariff. Among other things, PG&E will focus on continuing to improve the customer experience of rooftop solar and other DG choices.

Lack of visibility into DG generation data: In the California IOU service areas, DG vendors and customers are not required to provide sub-metered data on DG generation to the IOUs or to statewide planners. This lack of access to DG generation data creates challenges for customer understanding of NEM billing and may pose operational awareness challenges for utilities and planners as more DG, and particularly solar with variable generation, is incorporated into California's electrical system. Of increasing concern is the paucity of data regarding charge/discharge operation of BTM customer storage installation, particularly those installed in conjunction with rooftop solar.

Inability to use available technology to capture additional value and minimize operational impacts at high penetration levels: BTM PV systems are not metered by utilities for generation output. Visibility is restricted to the net usage (electric consumption net of solar generation) and exports to the grid that are measured by the utility revenue meter for customers participating in a NEM tariff. It is infeasible currently to collect data on the actual generation. While most vendors provide information to customers regarding their PV systems' production,

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[82] PG&E's Comments on Party Proposals and Staff Papers (Sept. 1, 2015) R.14-07-002, NEM Successor Tariff <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K655/154655659.PDF> (as of Oct. 26, 2022).

[83] PUC Section 2827.1(b)(4).

there are no collection standards and quality requirements for that data. Furthermore, there are limited existing data collection, delivery protocols, and communication infrastructure that could be used make the data available to utilities, regulators, or market participants. Significant investment in data collection and communication infrastructure would be required before BTM generation could be reliably used for market participation that relied on measured data from the generator, which may be necessary for realization of BTM PV value for certain system benefits.

x. Transportation electrification

PG&E is committed to increasing adoption of clean fuel vehicles, such as EV, hydrogen vehicles, and natural gas vehicles, in California to help the state meet its aggressive climate and clean transportation goals. PG&E's climate strategy is aligned with the underlying assumption of increased transportation electrification and higher GHG emission reductions, and the 2022 IRP's ATE scenario aligns closest with PG&E's internal load forecast for the post 2030 horizon. The 2021 IEPR mid EV forecast that was used for PG&E's Conforming Portfolios includes expected deployment of over 1.2 million clean fuel vehicles in its service territory by 2030 and 3.1 million statewide, in support of state regulations regarding zero-emission vehicles. PG&E's existing and soon to be implemented customer offerings address key barriers to transportation electrification and EV adoption throughout its service territory in support of those goals. Beyond approved state regulations, PG&E has committed to fueling 3 million EVs by 2030[84] which is aligned with recent goals set by the Governor. PG&E will continue to implement its existing CPUC approved infrastructure programs, Vehicle-Grid-Integration (VGI) pilots, Low Carbon Fuel Standard (LCFS) programs and offer EV-specific rates and rebates in the near term in support of its commitments, and the utility will also look for new opportunities aligned to PG&E's core capabilities to support the needs of EV drivers, including customers located in DAC, through additional program and rate design and through technology research and development.

Table 28 below provides a summary of PG&E's clean transportation actions, barriers, and recommendations.

[84] PG&E Climate Strategy Report (June 2022), <https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/pge-climate-goals/PGE-Climate-Strategy-Report.pdf> (as of Oct. 26, 2022).

TABLE 28
CLEAN TRANSPORTATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• Support medium- and heavy-duty vehicle charging infrastructure via PG&E's EV Fleet Program. • Expand light-duty charging options through PG&E's EV Fast Charge Program. • Expand charging infrastructure in state parks and schools through PG&E's EV Schools and Parks Program. • Support increased EV adoption among low-and-moderate-income customers through PG&E's Empower EV program. • Offer customers EV specific rates (e.g., EV-2A, EV-B, Business EV (BEV)) to provide low-cost fuel to customers. • Implement LCFS Holdback Programs to increase customer EV adoption. • Test vehicle-to-grid technologies through analysis and pilots.
Key Barriers	• Lack of availability of charging infrastructure. • Total cost of ownership. In particular, upfront EV costs tend to be higher than those of internal combustion engine vehicles. • Lack of EV awareness or understanding. • Inequitable access to EVs and EV charging. • Grid impacts due to magnitude of expected EV load.
Proposed New Near-Term Actions / Commission Direction	PG&E is not requesting any additional actions in this IRP. However, PG&E encourages the Commission to approve the following actions, which are currently open or will be filed in separate, future proceedings: • A decision on the Transportation Electrification Framework. • Approval of the Submetering Implementation Plan (to be filed in Dec 2022). • Approval of the VGI Dynamic Rates AL. • Approval of the Joint IOU Tier 3 AL with adjustments to the medium- and heavy-duty vehicle charging infrastructure programs. • Approval of PG&E's EV Charge 2 Application. • Approval of future proposed programs, including additional or extended LCFS Holdback programs or programs proposed under the CPUC's "Near-Term Priority" pathway.
Deviations from current resource plans	The activities listed above are all in support of PG&E's Climate Strategy goal of 3 million EVs deployed in PG&E's Service Territory by 2030. This is almost twice as many EVs deployed as planned in the current IRP.
Recommendations for Future IRPs	• Evaluate EVs in IRP as a candidate resource. • Incorporate higher EV load such as the IAWG ATE case.

PG&E is supporting the planned number of deployed EVs in the IRP through its duty to serve Service Planning Process. This includes:

Supporting interconnection of EV charging infrastructure through Electric Rule 29: PG&E's EV Infrastructure Rule 29 pays for and coordinates the design and deployment of service extensions from PG&E's electrical distribution line facilities to the service delivery point for separately metered EV charging stations for commercial, industrial, and multi-family customers. Rule 29 can support the anticipated increase in EV charging interconnection by reducing the cost and complexity for customers to install EV charging infrastructure.[85]

Planning for increased EV load through the Utility Distribution Planning Process: PG&E uses the approved CEC IEPR transportation electrification forecast to plan for necessary investments on the grid. The 2021 IEPR mid EV load forecast is integrated into PG&E's distribution planning process to inform where grid upgrades are needed and how much increased capacity is necessary. To prepare the grid for the EV load that is anticipated beyond the 2021 IEPR forecast, and in line with PG&E's 2030 EV commitments, PG&E received approval from the CPUC to plan to the higher EV forecast, the High Transportation Electrification IEPR scenario, for future years.

PG&E is currently supporting EV adoption within its service territory above and beyond the current EV deployment plan in the IRP through the following actions:

Support MDV/HDV Charging Infrastructure via PG&E's EV Fleet Program: Continue implementation of PG&E's EV Fleet Program by installing "make-ready" infrastructure for non-light-duty fleets at approximately 700 sites and supplying charging for approximately 6,500 vehicles.[86] Additional incentives are provided to sites in DACs, as defined by the CPUC, and to school and transit bus projects.

Expand Charging Options through PG&E's DC Fast Charging Infrastructure Program: Continue implementation of PG&E's EV Fast Charge Program to install approximately 40 sites for DC fast charging in corridor and urban sites, with at least 25 percent of sites located in DACs adjacent areas. Additionally, rebates are provided to sites in DACs.[87]

Expand Infrastructure in State Parks and Schools: Implement PG&E's EV Schools and EV Parks programs to install Level 2 and DC Fast Charging infrastructure targeting 15 state parks and beaches, and 16 school facilities and educational institutions within PG&E service territory.[88]

Support Increasing EV Adoption Among Low-and-Moderate Income Customers through Empower EV: PG&E's Empower EV offers a rebate for a residential charger, and in some cases

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[85] PG&E Electric Rule 29, <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_29.pdf> (as of Oct. 26, 2022).

[86] D.18-05-040.

[87] D.18-05-040.

[88] D.19-11-017.

panel upgrade, as well as tailored marketing, education, and outreach to meet the needs of low- and moderate-income customers with a focus on communities in Fresno, San Jose, and Brentwood/Oakley. PG&E will tailor Marketing, Education, and Outreach to best serve these communities with a focus on providing multi-lingual resources and leveraging a diverse set of marketing channels. PG&E is also partnering with a program implementer with close ties to the communities served to administer the Empower EV program.

Pilot Vehicle Grid Integration technologies: Implement three VGI pilots to evaluate use of vehicles for grid services and as backup power. These include a V2G pilot to provide backup power to residential customers in PSPS via their EVs, a pilot to test the use of commercial EVs to manage load/bills at commercial buildings, and a pilot to enable passenger and fleet EVs to charge and discharge in a PSPS-formed microgrid.[89]

Offer Customers EV Specific Rates (e.g., EV-2A, EV-B, BEV, and EV Submetering): PG&E has two residential EV rates designed to promote EV charging during times consistent with grid needs, EV2-A and EV-B.[90] The rates are differentiated based on whether the EV charging has a dedicated meter. Both rate plans use an un-tiered TOU rate structure. They offer on-peak, partial peak, and off-peak energy prices. Additionally, PG&E now offers an EV rate for commercial customers (Business EV Rate or BEV). PG&E offers two BEV plans, BEV-1 and BEV-2, based on charging installation load and combines a customizable monthly subscription charge with a TOU rate structure. PG&E will also begin implementation of its optional day-ahead real time rate for commercial EV customers on the BEV rates. Additionally, within approximately the next 2 years, PG&E will modify its billing system(s) to allow for non-NEM residential and business customers to begin submetering their EV load. This rate is intended to help EV charging occur at optimal times for the grid. Submetering will lower barriers to customers' access to low-cost EV-specific rates by eliminating the need for a separate meter

LCFS Holdback Programs: PG&E earns credits for providing low-carbon fuels and uses this off-bill revenue to fund customer programs to promote EV adoption. The LCFS programs have four guiding principles for their design and evaluation: i) maximize benefits utility customers; ii) advance the state's equity, resiliency, and climate goals; iii) support EV awareness and adoption; and iv) efficiently use funding. The four LCFS holdback programs are as follows:[91]

- **Pre-Owned EV Rebate:** Post-purchase rebate for pre-owned EVs. This is a $1,000 base rebate, with an additional $3,000 for income-qualified customers.
- **Multi Family Home and Small Business Direct Install Pilot:** Installation of low-power chargers (Level 1 and Level 2) at multifamily and small businesses with capacity on the panel.

[89] Res. E-5192, PG&E's AL 6529-E, May 6, 2022.

[90] Res. E-4508, PG&E's ALs 3910-E and 3910-E-A, August 27, 2012.

[91] PG&E AL 6226-E-A, pp. 4-5.

- **Residential Charging Solutions Pilot**: Educational resources and financial support to install residential EV charging which avoids panel upgrades.
- **Resiliency Pilot (evPulse for PG&E):** Communication and/or active management of residential customers' EV charging prior to a PSPS event to ensure their battery is charged before an event.

Customer Education: PG&E provides resources to support customers in their EV evaluation and purchasing considerations. PG&E's online EV Savings Calculator[92] is a customizable tool for residential customers that disambiguates total cost of ownership and pools together information on EV models, rates, incentives, and helps customers locate charging stations. The website also offers videos and checklists about EV charger installation. Additionally, PG&E offers an EV Fleet Calculator[93] to assist business customers in evaluating fuel savings and total cost of ownership for switching to an EV fleet.

PG&E has proposed the following program to continue its support of EV adoption and PG&E and the State's goals:

Expand charging infrastructure for multi-family housing residents: PG&E's proposed EV Charge 2-program[94] is an extension of the EV Charge Network and the EV Fast Charge programs and will support installation of L2 and DC fast charge charging ports at multi-family housing, workplaces, and public destinations. 50 percent of the program's infrastructure will be deployed in priority communities per AB 841.[95]

Key Barriers

Lack of availability of charging infrastructure: Access to EV charging infrastructure continues to be a major challenge across all vehicle types that contributes to range anxiety and hinders EV adoption. To date there are 41,921 public and private charging ports in California, 8,064 of which are Direct Current Fast Charging (DCFC).[96] Progress toward the state of California's goal of 250,000 charging ports, including 10,000 DCFC, has been slow in part due to the significant

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[92] PG&E EV Saving Calculator, <https://ev.pge.com/> (as of Oct. 26, 2022).

[93] PG&E EV Fleet Calculator, <https://ev.pge.com/> (as of Oct. 26, 2022).

[94] A.21-10-010, Application of Pacific Gas and Electric Company for Approval of its Electric Vehicle Charge 2 Program (Oct. 26, 2021).

[95] AB 841 (2021-2022 Reg. Sess.) <https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201920200AB841> (as of Oct. 26, 2022).

[96] Total public and private chargers in California from the Department of Energy's Alternative Fuels Data Center.

costs associated with EVSE installation. PG&E is committed to accelerating investment in infrastructure to aid progress toward this goal and address this gap.

Total cost of ownership: While EV technology continues to advance and model types increase, EVs can still cost more than traditional internal combustion engine vehicles. This is particularly true for medium- and heavy-duty vehicle types which currently have fewer EV options available and are significantly higher in price.

Lack of EV awareness or understanding: The decision to purchase an EV or convert a fleet involves awareness and understanding of new technology not limited to the vehicle itself but also the charging equipment, rate structures, and ways to maximize TOU benefits, as well as how to navigate the various incentive programs available to both residential and commercial customers.[97]

Inequitable access to EVs and EV charging: The key barriers to transportation electrification of lack of charging infrastructure and high upfront vehicle costs are exacerbated for hard-to-reach and underserved customers and communities. Low- and moderate-income customers often purchase cheaper pre-owned vehicles but are faced with fewer pre-owned EV options. Additionally, those customers may not have access to financing to be able to afford the upfront price of an EV even if there are after-purchase rebates available. There are also significantly fewer charging stations in disadvantaged communities or in areas that support customers who live in multi-family housing and can't charge EVs at home.

Grid impacts due to magnitude of expected EV load: The statewide goal of 5 million passenger vehicles by 2030 and 100% zero-emission passenger vehicle sales by 2035 and the complementary regulations for other transportation sectors will result in significant additional load to the grid which could exacerbate reliability issues. This will require new strategies and technologies, such as VGI, to successfully integrate future load of this magnitude.

xi. Building Electrification

In June 2022, PG&E issued its *Climate Strategy Report*, which established its goal to achieve a net zero energy system in 2040—five years ahead of the California carbon neutrality goal established in Executive Order B-55-18—and be climate and nature positive by 2050. PG&E recognizes the importance that building decarbonization must play in meeting these carbon goals and the specific leadership role that PG&E can serve in advancing zonal electrification as a part of a broader building and gas decarbonization strategy. In addition to PG&E's Energy Efficiency programs (detailed in Section A.8), PG&E has made a commitment in its *Climate Strategy Report* to "evaluate gas capital projects for electrification as an alternative to the planned gas projects and pursue electrification for the projects evaluated as feasible and

[97] A.17-01-022, PG&E's Transportation Electrification SB 350 Prepared Testimony (Jan. 20, 2017).

cost-effective." This focus on a managed transition through zonal electrification will ensure both greenhouse gas savings and long-term customer affordability.

Table 29 below provides a summary of PG&E's building electrification actions, barriers, and recommendations.

TABLE 29
BUILDING ELECTRIFICATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• PG&E has supported state and local government policies that promote all-electric new construction. Over 50 local jurisdictions, 43 of which are in PG&E's service territory, have adopted "reach" building codes either mandated or giving preference to all-electric new construction. PG&E has provided written support for these local efforts where they are cost effective and reduce emissions for its customers. • PG&E has supported the adoption of the 2022 California Title 24 Energy Code, which includes provisions around electric space and water heating, and continues to find ways to promote energy efficiency and electrification through its Codes and Standards partnerships. • In the California Public Utilities Commission Building Decarbonization proceeding (R.19-01-011), PG&E supported the elimination of gas line allowances, discounts, and refunds for all residential customers and the elimination as allowances, discounts, and refunds for non-residential customers where there was not a financial or environmental benefit to its customers.[98] • PG&E's *Climate Strategy Report* includes a 2030 goal to "evaluate gas capital projects for electrification as an alternative to the planned gas projects and pursue electrification for the projects evaluated as feasible and cost-effective.[99]" • The *Climate Strategy Report* also includes an effort to zonally electrify three to five communities, with a specific focus on the decarbonization of vulnerable communities. • PG&E has created a *Gas Asset Analysis Tool*, which highlights portions of the gas system which may make sense to further investigate zonal and/or targeted electrification.

[98] R.19-01-011, Opening Comments of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company on the Phase III Staff Proposal (Dec. 20, 2021), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K000/434000388.PDF> (as of Oct. 26, 2022).

[99] PG&E's Climate *Strategy Report* (June 2022), p. 22.

TABLE 29
BUILDING ELECTRIFICATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS (CONTINUED)

	• PG&E is participating in EPIC GFO-20-503 to "develop multi-disciplinary, strategic approaches for stakeholders and decision makers to determine where natural gas infrastructure retreat is plausible, economically viable, and ratepayer supported" with partners Gridworks, E3, and East Bay Community Energy. • On August 10th, PG&E filed an application with the CPUC that asks for up to $17.2 million to pursue "zonal" electrification for Phases 2-5 at CSU Monterey Bay (A.22-08-003). The costs of the zonal electrification project are anticipated to be fully offset avoided gas distribution replacement costs for these phases. • PG&E's innovative WatterSaver program and California Energy-Smart Homes Program, provide incentivizes low-carbon solutions in the building sector. • PG&E has developed an electrification website (https://www.pge.com/electrification) and email address (electrification@pge.com) to support its customers transitioning to all-electric homes and businesses. • PG&E provides no-cost electrification training to its customers and the building industry through its workforce education and training programs. In its *Climate Strategy Report,* PG&E included a goal for 50% of these programs to focus on electrification by 2030, with a goal of 60% of participants being from DAC. • PG&E will be releasing the E-ELEC electrification rate beginning in 2023. • PG&E is a supporter of the Switch is On, which provides technical assistance and contractor resources for those looking to make the switch to all-electric.

TABLE 29
BUILDING ELECTRIFICATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS (CONTINUED)

Key Barriers	• Obligation to serve. • External/non-traditional funding. • Financial reform for non-pipeline alternatives.
Proposed New Near-Term Actions / Commission Direction	PG&E is not requesting any additional actions in this IRP.
Deviations from current resource plans	None.
Recommendations for Future IRPs	Incorporate building electrification demand in future IRPs.

Key Barriers

Obligation to serve: Due to PUC Code 451 (“obligation to serve”), one hold-out can lead to failure of a zonal electrification effort, even if electrification is the best financial or environmental outcome for customers. A legislative reform to obligation to serve would allow for greater building electrification potential.

External/non-traditional funding: External funding will be critical to ensuring that PG&E can pursue electrification while minimizing the impact on remaining gas customers, many of whom are likely to be low-income customers.

Financial reform for non-pipeline alternatives. PG&E believes that zonal electrification can reach wider scale and scope if PG&E were to have appropriate rate recovery for zonal electrification projects, for example allowing recovery of costs as a regulatory asset over a 15-year period. This would allow utilities such as PG&E to evaluate gas investments and electrification on more equal financial footing and pursue the option that is more cost effective for its customers.

xii. Other

PG&E has not identified any other resources not covered in the above sections.

b. Disadvantaged Communities

In implementing its IRP Action Plan, PG&E is committed to serving customers in DAC. Regarding outreach to DAC, PG&E describes its existing outreach activities in this section as well as Sections III.d.ii and in Appendix 2: PG&E DAC Programs. Given evolving market dynamics, PG&E's current energy procurement and customer engagement activities are driven primarily by state policy mandates and the implementation of DSM programs, many of which already include targeted offerings to DAC communities.

i. DAC Activities/Programs

PG&E has a wide array of programs available to customers residing in DACs. A full list of programs is available in Appendix 2, with selected programs highlighted below:

- Building Electrification pilots targeted to residents of DACs and/ or low-income customers promote clean indoor air quality for participants as well as provide broader environmental benefits. The San Joaquin Valley Clean Energy Pilots have been converting appliances in customer homes from propane to electric since the pilot launch in 2020. The Energy Savings Assistance (ESA) program Pilot Plus/ Pilot Deep program launched in late 2022 and will include electrification of select participating customer homes, especially those with high energy usage.
- Clean transportation programs targeted to residents in DACs help mitigate local air quality concerns. Programs with specific focus on DACs include Empower EV, the EV Charge 2 proposal, and the Used EV Rebate, which are discussed in more detail in the Transportation Electrification section above.

PG&E's programs targeted to customers residing in DACs have evolved over the years to include more programs providing greater access to clean technologies that help minimize criteria air pollutants both inside customer homes and in the broader community. PG&E anticipates that there will continue to be more programs developed to help address and mitigate poor air quality in DACs, particularly programs that have a direct impact such as expanding access to EVs and building electrification.

ii. DAC Outreach

PG&E has not conducted outreach for this IRP filing due to time constraints but plans to conduct outreach for future IRPs. PG&E currently conducts outreach for many programs, primarily through partnerships with CBOs to assist in reaching hard to reach customers segments, such as customers residing in DACs or rural communities. PG&E anticipates that outreach efforts for future IRPs will build on and collaborate with efforts in other similar forums to leverage existing local outreach already underway. One key example to follow is the outreach conducted for the Climate Vulnerability Assessments, which includes overlaps with DAC customers. For future IRP cycles, PG&E anticipates that lessons learned from past outreach efforts will be leveraged to best reach impacted customers, and a robust outreach plan will likely have the following key elements:

- Contracted partnership with CBOs in impacted communities to best facilitate community outreach and engagement

- Partnership with internal PG&E teams including Local Government Affairs and Regional VP teams to inform and engage government and community leaders in impacted communities
- Meeting advertisements and materials available in primary languages spoken in impacted communities
- Outreach conducted in multiple cycles to introduce the procurement plan, solicit feedback, and inform residents of the final adopted procurement plan
- Information about additional programs available to customers residing in DACs to encourage enrollment in mitigating programs (such as clean energy programs or bill assistance rate programs). This outreach is already happening via other programs such as the ESA Program through local contractors who perform energy education in addition to weatherization services. This program reaches approximately 60,000 homes per year, and 25% of all homes treated are located in DACs[100]

PG&E has not developed metrics or scoring criteria for incorporating community input into the planned procurement activities but plans to begin discussions with internal and external stakeholders to develop a set of metrics that are feasible and reasonable before the next IRP filing.

c. Commission Direction or Actions

i. IRP Procurement Track

As noted earlier in the Study Results Sections III, PG&E anticipates that it will need to procure additional resources to meet its 2030 IRP GHG emission target and California's clean energy goals. Based on its IRP analysis, PG&E shows a need of approximately 12 TWh of incremental GHG-free resources by 2030. As a result of this need, PG&E requests authority to begin soliciting for GHG-free resources in 2023 in order to facilitate gradual procurement to avoid the reliability and, in some cases, cost impacts occurring today due to shortages and project delays. PG&E may procure less than 12 TWh depending on the resource mix procured, changes in PG&E's load forecast, outcomes of ongoing regulatory proceedings, or procurement resulting from additional future mandates. PG&E will continue to update and refine its analysis and subsequent need based on the latest available information as it moves forward to help determine the amounts and products that PG&E plans to procure in the future.

An early and flexible procurement approach will (1) help PG&E plan for potential changes in its need year and (2) realize potential benefits from gradual procurement including balancing the

[100] PG&E's ESA, CARE, and Family Energy Rate Assistance (FERA) Program Monthly Report for July 2022, ESA Program Table 7, <https://liob.cpuc.ca.gov/wp-content/uploads/sites/14/2022/09/PGE-JULY2022-Low-Income-Monthly-Report.pdf?emrc=ff7506> (as of Oct. 28, 2022).

certainty of procuring conventional GHG-free resources today with the opportunity to procure emerging technologies as they develop.

Request for Procurement Authorization

PG&E requests the Commission explicitly provide PG&E with procurement authority in its decision approving PG&E's 2022 IRP. PG&E proposes the following language be adopted by the Commission as an ordering paragraph in the decision that would provide PG&E with procurement authority to fulfill the procurement need identified by its 2022 IRP:

> "PG&E is authorized to initiate resource procurement activities, including solicitations and bilateral negotiations beginning in 2023, to meet the needs identified in its 2022 IRP or any subsequent update thereto approved by the Commission. Resources procured under this authorization may also count towards future procurement mandates or compliance requirements established by the Commission in this proceeding. PG&E shall submit a Tier 3 AL for approval of contracts for resources procured by PG&E pursuant to this ordering paragraph, unless such contracts are also authorized pursuant to any other proceeding before the Commission in which case such contracts may be presented pursuant to a Tier 1 AL. For administrative efficiency, more than one contract may be presented to the Commission in each AL submission."

PG&E is seeking approval to procure new resources via procurement activities such as solicitations and bilateral negotiations. While solicitations may allow PG&E to understand overall market depth, PG&E also seeks authority to procure via bilateral negotiations to ensure it can take advantage of any unique or fleeting opportunities in the market.

Potential for Need Year Change

As noted in PG&E's 2022 Draft RPS Plan[101] PG&E's need year may change as a result of several factors:

- Uncertainty regarding VAMO implementation ordered under D.21-05-030 including a final decision on what may happen to any volumes unsold in the Market Offer Process. This can impact PG&E's RPS supply portfolio and ultimately its need year.
- Mandated Procurement (e.g., for reliability purposes, procurement orders via IRP, etc.) that includes RPS-eligible or GHG-free resources may impact PG&E's future GHG-free position and subsequently its procurement need.
- Changes in load forecast such as increased electrification, adoption of energy efficiency resources, EV adoption, future CCA departure, or customer return can impact PG&E's forecasted customer load and load shape impacting PG&E's need year.

[101] PG&E's 2022 Draft RPS Plan (July 1, 2022) R.18-07-003, Section IV.A.3, PG&E's RPS Procurement Need for New Resources Before 2030, <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=709459> (as of Oct. 26, 2022)

- New laws increasing or expanding upon GHG-free requirements may change PG&E's total GHG-free energy need and/or change PG&E's need year.
- Procurement by the Central Procurement Entity (CPE) or another procurement entity of GHG-free resources that are allocated to PG&E's bundled service customers.
- The Available resource mix to build or contract may impact PG&E's total need and ultimately its need year since different technologies have different marginal emissions reductions benefits. This may require more resources and potentially more time (or fewer resources depending on the generation profile) depending on what is available in the market.
- Other unforeseen regulatory or market changes

Benefits of Gradual Procurement

Although there are several years until PG&E's 2030 need year, PG&E believes that beginning solicitations as soon as possible is prudent to achieve its IRP goals and procure resources gradually. For example, the 2021 SB 100 Joint Agency Report shows 50,000 MW of cumulative capacity additions needed by 2030.[102] In particular, the report found that average 25-year build rates must be 2,800 MT for solar, 900 MW for wind and 2,000 MW for storage each year. These levels are greater than have ever occurred for California in single year. Procuring new GHG-free resources gradually may help mitigate future risk including but not limited to:

- Uncertainties regarding project development timeframes including supply chain constraints or delays;
- Significant demand for projects, including new construction and emerging resources (e.g., OSW) as LSEs ramp up procurement for increasing RPS and GHG emission requirements for 2030 and beyond;
- Potential cost impacts due to state and federal policy changes in Investment Tax Credits and/or tariffs on imported materials;
- Potential increase in demand due to increased electrification, especially across the transportation sector;
- Potential transmission constraints for new projects, and potential scarcity of viable projects if required transmission infrastructure does not keep pace with the number of new resources needed; and
- Potential for competition for out-of-state resources as jurisdictions outside California increase their climate mitigation efforts.

[102] 2021 SB 100 Joint Agency Report (March 15, 2021), p. 10, Figure 3, <https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity> (as of Oct. 26, 2022).

In addition, PG&E has historically procured gradually to meet other goals such as RPS compliance[103] by layering procurement over multiple years. This strategy helps mitigate price and project failure risk while reducing the potential for over- or under-procurement by allowing time to explore options and reassess market conditions as PG&E's supply portfolio and demand change and as new technologies emerge and industries adapt to tax incentives. With this in mind, PG&E proposes to go to market as early as possible in 2023 to begin procurement. More detail on the attributes associated with the type of resources PG&E is seeking procurement authority for can be found in Table 30 below.

TABLE 30
IRP PROCUREMENT REQUEST PRODUCT INFORMATION

Attribute	Contract Term <= 5 Years	Contract Term >5 Years
Deliverability Status	Full Capacity Deliverability Status (FCDS), Partial Capacity Deliverability Status (PCDS), or Energy Only (EO)[(a)]	FCDS, PCDS, or EO
Resource Vintage	Existing	New or Existing
Delivery Year(s)	Online and Delivering by 2030	Online and Delivering by 2030
Approval Vehicle	Tier 3 AL	Tier 3 AL
Type	GHG-free (with or without storage)	GHG-free (with or without storage)
Resource	3rd Party	UOG or 3rd Party
Volume Seeking	Amount based on gradual procurement for need year	Amount based on gradual procurement for need year

Generally, PG&E agrees that the programmatic approaches described in D.22-02-004 could help increase predictability, ensure alignment, allow flexibility, prevent leaning by LSEs, and increase market efficiency while conducting planning, procurement, and operational activities to meet the state's climate goals. The procurement authorization request by PG&E would not necessarily be different under different procurement programs because PG&E's need in 2030 remains the same. While the specific types, quantities, and timeline for resources procured may change depending on the programmatic approach selected, PG&E believes that its proposal to procure gradually will allow us to adjust, if necessary, to any IRP procurement frameworks adopted by the Commission. This is because, ultimately, its procurement request aligns with the Commission's desired objective of co-optimizing future procurement to meet

[103] PG&E's 2022 Draft RPS Plan (July 1, 2022) R.18-07-003, addresses the benefits of early procurement in Section IV.A.3, pp. 27 -31, <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=709459> (as of Oct. 26, 2022).

RPS, GHG-free energy, GHG-emissions, and reliability goals by taking a proactive LSE-driven approach that emphasizes sufficient planning time, commercial flexibility, and resource diversity. Additionally, PG&E plans to submit all contracts for Commission approval via Tier 3 advice letters.

PG&E's request procurement is based on its bundled portfolio needs. If the Commission adopts a non-need-based allocation approach going forward, PG&E's procurement request may be too low or too high. PG&E continues to support need-based procurement allocations, in part because this approach encourages proactive actions by LSEs by removing risk associated with over-procurement due to non-need-based procurement decisions. To that end, PG&E requests that any procurement undertaken as a result of this procurement request count toward any procurement requirements adopted as part of a new programmatic procurement framework (e.g., would not be considered "baseline" for 2030 or 2035 need-driven procurement).

PG&E's request also does not assume any centralized procurement on long-lead time GHG-free resources. PG&E encourages the Commission to adopt a programmatic approach that offers a predictable approach for any centralized procurement. Any centralized procurement or procurement mandates that are allocated on a load share basis should be communicated to LSEs in a timely manner, so that LSEs can incorporate such quantities, and types, of attributes from such additional resources to be procured in order to determine their impact on the LSEs' remaining portfolio needs.

PG&E will provide additional details on its recommendations and will provide its feedback to the programmatic procurement framework outlined in the "Staff Options Paper on Reliable and Clean Procurement" in comments PG&E plans to submit in response to the ALJ Ruling requesting comments on the procurement framework.

ii. New Spending Authorizations

PG&E will secure independent evaluation of its procurements by an Independent Evaluator (IE) to provide third-party oversight of any solicitation activities. PG&E proposes to recover the costs of the IE for any of the solicitations for procurement conducted on behalf of this request be included in the appropriate PABA subaccount.

iii. Changes to Existing Authorizations

PG&E currently has partial procurement authority for resources that may help meet the needs identified in its 2022 IRP filing. Specifically, PG&E's Bundled Procurement Plan authorizes transactions for contracts of shorter than 5 years for energy and capacity products, but not for renewable products. In addition, the procurement order laid out in D.21-06-035 authorizes reliability procurement for resources with online dates mid-decade through 2028. Earlier this year, PG&E requested additional procurement authority for short-term and long-term products in its Draft 2022 RPS Plan based on its demonstrated RPS need. The Commission has not yet acted on this request.

Generally, PG&E is not seeking any changes to previously issued Commission procurement authorizations or procurement authorization currently under consideration by the Commission. Although procurement conducted for other purposes (e.g., RPS Compliance) may improve PG&E's GHG-free and GHG emissions positions, PG&E is requests additional procurement authority in this filing based on the results from its 2022 IRP analysis. This incremental request will help PG&E facilitate gradual procurement needed to meet its 2030 IRP goals while offering the ability to adjust its executed procurement based on new supply, demand, and market information to reduce the likelihood of under- or over-procurement.

While PG&E is not specifically requesting any additional Commission actions beyond the one request for procurement authorization in this IRP, PG&E encourages the Commission to consider potential actions which are currently open or will be filed in separate, future proceedings. PG&E has summarized these potential actions in Table 31 below.

TABLE 31
SUMMARY OF PROPOSED NEW NEAR-TERM ACTIONS/COMMISSION DIRECTION OF ACTION

IV Action Plan Section	Proposed New Near-term Actions / Commission Direction	Reference
v. Renewable Energy	PG&E has submitted a request for renewable energy procurement in its Draft 2022 RPS Plan.	Table 23
vii. Demand Response	Approval of PG&E’s 2023 Bridge Year Application Consideration of PG&E’s proposals in its 2024-2027 Application	Table 25
viii. Energy Efficiency	Commission should approve PG&E’s 2024-2031 EE Strategic Business Plan	Table 26
ix. Distributed Generation	The new NEM tariff structure should be reformed to correct the inequities created by the existing NEM tariff while incentivizing customer generation and storage technologies in a way that better aligns the interests of all customers and the grid.	Table 27
x. Transportation Electrification	A decision on the Transportation Electrification Framework Approval of the Submetering Implementation Plan (to be filed in Dec 2022) Approval of the VGI Dynamic Rates AL Approval of the Joint IOU Tier 3 AL with adjustments to the medium- and heavy-duty vehicle charging infrastructure programs Approval of PG&E’s EV Charge 2 Application Approval of future proposed programs, including additional or extended LCFS Holdback programs or programs proposed under the CPUC’s “Near-Term Priority” pathway.	Table 28

V. Lessons Learned

During the current IRP cycle, the CPUC recognized the need to design a new programmatic approach to procurement[104] to help better determine more efficient and longer-term contracting procurement requirements for reliable and clean resources. PG&E applauds the CPUC for examining a fundamental overhaul in this process to make the process more efficient, effective, and predictable. PG&E is pleased to participate in this separate process and believes that it is an appropriate forum for it and other LSEs to bring up suggested changes for consideration. Many of the lessons learned from this year's IRP cycle already appear to be teed up for discussion in the questionaries for the Reliable and Clean Power Procurement Program Staff Options Paper. PG&E offers the following additional recommendations to further improve the Commission's integrated resource planning.

a. Capacity Expansion Modeling Tool Enhancement

The grid and capacity modeling capabilities need to grow along with the planning challenges California is facing. PG&E recommends that the Commission enhance its capacity expansion modeling capabilities to ensure that the tools are adequate for addressing the existing and emerging resource planning challenges.

The Commission's use of a robust loss of load expectation model has improved reliability analysis occurring in the IRP proceedings; use of a similarly robust model for capacity expansion modeling and IRP portfolio development could be another modeling capability improvement that the Commission should consider.

Utilizing a more robust modeling software suite will allow more granular and robust analytics that can lead to improved planning. For example, the Commission's current capacity expansion tool dispatches resources by aggregate resource class to meet CAISO demand, with no zonal considerations and 37 representative days. A robust capacity expansion model would allow individual unit dispatch to inform capacity expansion modeling with CAISO zonal considerations and annual 8,760 hourly functionality, improving modeling granularity. Similarly, it will provide greater flexibility for modeling demand side solutions as candidate resources, a feature crucial for successful implementation of advance load management solutions in the IRP.

b. Planning for Reliability

A comprehensive reliability assessment is a key element of the IRP process. Acknowledging that recent IRP process improvements address some of the reliability assessment gaps, PG&E

[104] CPUC, Energy Division Workshop, Reliable & Clean Power Procurement Program Staff Options Paper (Sept. 20, 2022), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-09---rcpp-program-workshop-slides.pdf> (as of Oct. 26, 2022).

continues to recommend the following actions to ensure that a comprehensive reliability assessment is a part of CPUC's resource planning process:

i. Loss of Load Expectation Model Enhancement

PG&E applauds the Commission's ongoing efforts to improve its model assumptions and offers the following recommendations for further enhancement of the model:

- For reliability modeling, PG&E supports consideration and robust modeling of north-to-south Path 26 transmission constraints in the Commission's LOLE analyses. Incorporation of this important zonal constraint is necessary to make planning decisions that will ensure power can be provided from generators to load areas.

  Historically, RESOLVE has built significant resource capacity south of Path 26. For example, the 2021 PSP selected more than 80% of incremental resource capacity south of Path 26. The Path 26 transmission limits in SERVM should be used to ensure the 2023 PSP portfolio does not result in inefficient resource capacity selection in either the north/south Path 26 region, resulting in divergent regional LOLEs. Inefficient resource capacity selections between north and south of Path 26 must be identified prior to the adoption of any IRP portfolio, especially as IRP portfolios are a key input in the CAISO's Transmission Planning Process (TPP).

- The increased frequency and severity of extreme weather events in the past several years highlights the need for more work to adequately address the impacts of climate change. LOLE reliability modeling is designed to stochastically address uncertainty, including variability due to weather. However, recent weather events suggest the LOLE framework may be inadequate to assure the desired levels of reliability. PG&E looks forward to engaging with the Commission and stakeholders on this fundamental planning issue. For immediate action, PG&E recommends that the Commission implement the following before finalizing the 2023 Preferred System Plan (PSP):
  - The Commission should include weather conditions from 2021 and 2022 in reliability modeling. The core intent of LOLE reliability modeling is to stochastically capture uncertainty. The Commission recently incorporated weather years 2018-2020 and encourages the addition of weather years 2021 and 2022 to ensure alignment with the most recent data available. The additional weather years 2018-2020 resulting in approximately one to one-and-a-half gigawatts (GW) of incremental perfect capacity needed to achieve the industry standard 0.1 LOLE reliability target – demonstrating a significant impact on reliability results with additional weather years. Given the unprecedented load seen in September 2022, the most recent weather data should be reflected in the 2023 PSP reliability modeling.
  - The Commission should utilize the CEC's 2023 Integrated Energy Policy Report (IEPR) in RESOLVE and SERVM. The 2023 IEPR forecast should be released by the

CEC in January 2023. Recent IEPR forecast updates have incorporated improved electrification demand forecasts and demand shapes. The underlying load forecast has a significant impact on IRP portfolios developed through RESOLVE capacity expansion modeling. Ensuring the most recent and accurate load forecast is used is critical to meeting reliability requirements and the determined reliability of the portfolio assessed in SERVM production cost modeling. ED should have sufficient time between the release of the 2023 IEPR in January 2023 and the scheduled Q3 2023 IRP ruling on the proposed 2023 PSP to ensure modeling alignment with the 2023 IEPR forecast.

- For future modeling enhancement to capture the impact of load management solutions on LOLE, PG&E asks the Commission to create a separate workstream focused on all aspects of load management solution modeling in the IRP. Modeling of load management in the IRP will not be a trivial task. It requires a dedicated stakeholder process to ensure that the IRP models are capable of providing cost-effective supply and demand side solutions to address reliability and GHG emission reduction goals in a cost-effective manner. See additional details below in the Integrated Planning section.

ii. Local Reliability Assessment

The lack of a local reliability assessment continues to be a gap in the IRP process that needs to be addressed immediately. The Assigned Commissioner's Ruling related to identifying replacement resources (including local capacity need) to allow the retirement of Aliso Canyon[105] highlights the needs for a systematic and coordinated effort between the CAISO and the CPUC to develop a plan for local area capacity requirements[106] to address the local need in a timely manner.

A significant amount of existing capacity on the CAISO system is located in local areas. These local areas must rely on local resources due to transmission limitations. Typically, the local area resource requirements are met by existing resources. As long as the existing resources do not

[105] *Assigned Commissioner's Ruling Entering Into the Record Energy Division Proposal and Ordering Testimony* (Sept. 23, 2022) I17-02-002, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K170/497170260.PDF> (as of Oct. 26, 2022).

[106] Per 2022-23 CAISO TPP Study Plan, since Aliso Canyon supports electric generation located in the Los Angeles (LA) Basin its closure could have "potential reliability impacts to the transmission facilities in the LA Basin and to some extent San Diego Imperial Valley local capacity areas in the CAISO Balancing Authority Area… ." CAISO, 2022-2023 Transmission Planning Process Unified Planning assumptions and Study Plan, Rev. 1 (June 30, 2022), pp. 77-78, Section 7.1, <http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf> (as of Oct. 26, 2022).

retire or local area loads do not increase significantly, a local capacity resource need assessment is not required. However, given the aging gas-fired resources and plan for significant load growth due to electrification demand (building and transportation), conducting a local capacity need assessment should be in scope of CPUC's IRP process in close co-ordination with the CAISO. The CAISO is in the best position to provide details on location specific resource requirements and support the identification of an integrated, cost-effective solution (e.g., portfolio of resources, transmission alternatives) to adequately address location specific requirements.

c. Improvement in Key IRP Modeling Assumptions

i. Existing Resource and Assumptions

As described in Section III.h, PG&E recognizes that the issue of future contract assumptions for existing resources, both GHG-free and GHG-emitting, is critical to address in order to improve the LSE planning process for future IRP cycles. Without a prescribed approach from the CPUC, aggregated LSE plans are likely to misrepresent existing resources and be misaligned with the Updated PSPs.

One solution for the CPUC to consider is to proportionally allocate the GHG-free energy attributes and both GHG-free and GHG-emitting reliability attributes for existing resources for all years after their existing contracts expire through the planned retirement date assumed for each resource. The list of applicable resources and future contract expiration dates can be determined based on the CPUC's system resource dataset and LSEs' annual RDT submittals that include details regarding their contract portfolios. This would ensure a more equitable representation of planned new procurement across LSEs within their IRPs while actual future LSE procurement will likely be a combination of agreements with both new and existing generators.

ii. LSE GHG Emissions Modeling

PG&E recognizes the complexity and challenges in developing a GHG emissions methodology at the LSE-level that is consistent with overall system emissions, in particular for hours where there is expected curtailment or exports of renewable resources. The current approach reflects an hourly-based GHG emission methodology for LSEs that reflect the SERVM modeling results from the updated PSPs for the 30 MMT and 25 MMT scenarios. This results in LSEs both identifying incremental resource additions based on their GHG emission impact in a future system that assumes all of the incremental PSP resources having already been built as well as being penalized for GHG-free generation from their existing resource portfolio during hours where the fully built PSP results in renewable curtailment or exports at the system level. Alternatively, some recognition for hours where the system emission reduction benefit is lower, or zero, compared to other hours is critical for developing a reliable, lower GHG emission system comprised of a diverse set of resource technologies. PG&E encourages the CPUC to continue pursuing future updates to the LSE GHG emission modeling methodology to help address these observed challenges.

iii. Baseline Hydroelectric System Assumptions

While LSEs have the flexibility for specifying their individual hydroelectric generation forecast assumptions, PG&E recommends the CPUC adopt a methodology similar to PG&E's for RESOLVE. Specifically, the CPUC should consider basing the hydroelectric generation forecast on recent 15-year historical generation. This baseline should then be adjusted for the RCP 8.5 scenario, which the CPUC began requiring IOUs to use for planning purposes in D.19-10-054, as well as the expected impacts from FERC license conditions that are expected to result in less water allocated to hydroelectric generation.

d. Integrated Resource Planning

As stated on the CPUC's website,[107] the intent of the IRP proceeding is to be "*an umbrella planning proceeding to consider all of the Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply*". PG&E agrees, with the intent. Given the increasing opportunity to include load management solutions to support the state goals and the need to consider cost-effective infrastructure upgrades that interact with supply and demand side solutions, PG&E offers the following recommendation to systematically fill in the planning gaps and complete the transition for the IRP proceeding to truly become an umbrella planning proceeding:

i. BTM Resource and Load Management Solutions Modeling

PG&E applauds the Commission's efforts for refinement of Demand Response potential and the consideration of Vehicle to Grid Integration (VGI) as a candidate resource in the Commission's 2023 Preferred System Plan and encourages the Commission to further integrate demand side resources into the IRP optimization process.

Recognizing the needed effort and wanting to ensure adequate time and attention for this important task, PG&E asks the Commission to start a separate IRP track to: (i) fully develop modeling capabilities, (ii) identify and streamline (or consolidate) interactions with other demand side proceedings, and (iii) establish workable interactions with the CEC IEPR and CAISO TPP processes to ensure that the state is ready to seamlessly consider demand- and supply- side cost-effective solutions in its planning efforts.

Critical to this effort will be close coordination with the CEC's load forecasting efforts to ensure resources are not double-counted as both demand modifiers and supply resources, as well as

[107] Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP), https://www.cpuc.ca.gov/irp/ (as of Oct. 26, 2022).

other DER planning proceedings at the CPUC and CEC that are investigating optimal investments in DERs.

Equally important will be coordination with transmission and distribution planning to ensure impact of demand side solutions on transmission and distributions systems is captured in a timely manner.

Lastly, validating potential demand side solutions with customers for inclusion in the model is important. PG&E will be launching several CPUC-approved VGI pilots in the next year and would be willing to share data and lessons learned about enrollment and costs of VGI programs to help inform this modeling effort.

ii. Co-ordination with the CAISO for an Assessment of Integrated Solutions

The 2021 Preferred System Plan decision included two storage projects in PG&E's service area. These projects were proposed by the CAISO as transmission alternatives. The process of alternatives assessment and allocation of procurement responsibility provided valuable lessons that should inform future processes. In its opening comments on the Proposed Decision to adopt the 2021 Preferred System Plan,[108] PG&E highlighted the gaps in the cost and project viability analyses that became hurdles for successfully implementing storage as transmission alternative. In addition, the issue of fair cost allocation of transmission alternatives to all benefiting customers (not just CPUC jurisdictional) needs to be addressed. These lessons learned should inform the future assessment of transmission alternatives.

[108] Opening Comments of Pacific Gas and Electric Company (U 39 E) On the Proposed Decision to Adopt the 2021 Preferred System Plan (Jan. 14, 2022) R.20-05-003, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M441/K160/441160118.PDF> (as of Oct. 26, 2022).

VI. Glossary of Terms

A.: Application

AB: Assembly Bill

AL: Advice Letter

ALJ: Administrative Law Judge

Alternative Portfolio: LSEs are permitted to submit "Alternative Portfolios" developed from scenarios using different assumptions from those used in the Preferred System Plan with updates. Any deviations from the "Conforming Portfolio" must be explained and justified.

Approve (an IOU, ESP or CCA Plan): The CPUC's obligation to approve an LSE's integrated resource plan derives from Public Utilities Code Section 454.52(b)(2) and the procurement planning process described in Public Utilities Code Section 454.5, in addition to the CPUC obligation to ensure safe and reliable service at just and reasonable rates under Public Utilities Code Section 451.

ATE: Additional Transportation Electrification

BAA: Balancing Authority Area (CAISO): The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

BART: Bay Area Rapid Transit

Baseline Resources: Those resources assumed to be fixed as a capacity expansion model input, as opposed to Candidate resources, which are selected by the model and are incremental to the Baseline. Baseline resources are existing (already online) or owned or contracted to come online within the planning horizon. Existing resources with announced retirements are excluded from the Baseline for the applicable years. Being "contracted" refers to a resource holding signed contract/s with an LSE/s for much of its energy and capacity, as applicable, for a significant portion of its useful life. The contracts refer to those approved by the CPUC and/or the LSE's governing board, as applicable. These criteria indicate the resource is relatively certain to come online. Baseline resources that are not online at the time of modeling may have a failure rate applied to their nameplate capacity to allow for the risk of them failing to come online.

BESS: Battery Energy Storage System

BEV: Business Electric Vehicle

BioMAT: Bioenergy Market Adjusting Tariff

BioRAM: Bioenergy Renewable Action Mechanism

BIP: Base Interruptible Program

BPOT: Bundled Portfolio Optimization Tool

Breakthrough Load Management and Emerging Technologies: Breakthrough load management and emerging technologies includes utilizing newer technologies (e.g., hydrogen and carbon capture, utilization, and sequestration) and includes accelerated adoption by customers of DER programs (PV and storage), smart technologies (EVs, smart thermostats and appliances) and efficiency measures to turn behind the meter and distributed resources into dispatchable resources.

BTM: Behind the Meter

BYOT: Bring Your Own Thermostat

CAISO: California Independent System Operator

CalEPA: California Environmental Protection Agency

CAM: Cost Allocation Mechanism

Candidate Resource: Those resources, such as renewables, energy storage, natural gas generation, and demand response, available for selection in IRP capacity expansion modeling, incremental to the Baseline resources.

Capacity Expansion Model: A capacity expansion model is a computer model that simulates generation and transmission investment to meet forecast electric load over many years, usually with the objective of minimizing the total cost of owning and operating the electrical system. Capacity expansion models can also be configured to only allow solutions that meet specific requirements, such as providing a minimum amount of capacity to ensure the reliability of the system or maintaining greenhouse gas emissions below an established level.

CARB: California Air Resources Board

CARE: California Alternative Rates for Energy

CBO: Community Based Organization

CBP: Capacity Bidding Program

CCA: Community Choice Aggregators

CEC: California Energy Commission

Certify (a Community Choice Aggregator Plan): Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. "Certify" requires a formal act of the Commission to determine that the CCA's Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.

CHP: Combined Heat and Power

Clean System Power (CSP, formerly "Clean Net Short") Methodology: The methodology used to estimate GHG and criteria pollutant emissions associated with an LSE's Portfolio based on how the LSE will expect to rely on system power on an hourly basis.

CO_2: Carbon Dioxide

Community Choice Aggregator: A governmental entity formed by a city or county to procure electricity for its residents, businesses, and municipal facilities.

Conforming Portfolio: The LSE portfolio that conforms to IRP Planning Standards, the 2030 and 2035 LSE-specific GHG Emissions Benchmark, use of the LSE's assigned load forecast, use of inputs and assumptions matching those used in developing the Preferred System Portfolio, as well as other IRP requirements including the filing of a complete Narrative Template, a Resource Data Template and Clean System Power Calculator.

CPE: Central Procurement Entity

CPUC or Commission: California Public Utilities Commission

CS-GT: Community Solar Green Tariff

D.: Decision

DA: Direct Access

DAC: Disadvantaged Communities

DAC-GT: Disadvantaged Communities Green Tariff

DAC-SASH: Disadvantaged Communities Single-family Affordable Solar Homes program

DCFC: Direct Current Fast Charging

DCPP: Diablo Canyon Nuclear Power Plant

DER: Distributed Energy Resource

DG: Distributed Generation

DR: Demand Response

DRAM: Demand Response Auction Mechanism

DRP: Demand Response Provider

DSM: Demand-Side Management

E3: Energy and Environmental Economics

ED: Energy Division

EDU: Electric Distribution Utility

EE: Energy Efficiency

Effective Load Carrying Capacity: A percentage that expresses how well a resource is able avoid loss-of-load events (considering availability and use limitations). The percentage is relative to a reference resource, for example a resource that is always available with no use limitations. It is calculated via probabilistic reliability modeling and yields a single percentage value for a given resource or grouping of resources.

Effective Megawatts (MW): Perfect capacity equivalent MW, such as the MW calculated by applying an ELCC % multiplier to nameplate MW.

Electric Service Provider: An entity that offers electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Public Utilities Code Section 218.

ELRP: Emergency Load Reduction Program

ERRA: Energy Resource Recovery Account

ESA: Energy Savings Assistance

EV: Electric Vehicles

FERA: Family Electric Rate Assistance

FERC: Federal Energy Regulatory Commission

Filing Entity: An entity required by statute to file an integrated resource plan with CPUC.

Future: A set of assumptions about future conditions, such as load or gas prices.

GHG: Greenhouse Gas

GHG Benchmark (or LSE-specific 2030 and 2035 GHG Benchmarks): The mass-based GHG emission planning targets calculated by staff for each LSE based on the methodology established by the California Air Resources Board and required for use in LSE Portfolio development in IRP.

GHG Planning Price: The systemwide marginal GHG abatement cost associated with achieving a specific electric sector 2030 GHG planning target.

GRC: General Rate Case

GTSR: Green Tariff Shared Renewables

GW: Gigawatts

GWh: Gigawatt-hour

IAWG: Inter-Agency Working Group

IE: Independent Evaluator

IEPR: Integrated Energy Policy Report

Integrated Resource Planning (IRP) Process: IRP process; integrated resource planning process; the repeating cycle through which integrated resource plans are prepared, submitted, and reviewed by the CPUC.

Integrated Resources Planning Standards (Planning Standards): The set of CPUC IRP rules, guidelines, formulas, and metrics that LSEs must include in their LSE Plans.

IOU: Investor-Owned Utility

IRA: Inflation Reduction Act of 2022

IRP: Integrated Resource Planning

kW: Kilowatt

kWh: Kilowatt-hour

lbs.: Pounds

LCOE: Levelized Cost of Energy

Load Serving Entity: An electrical corporation, electric service provider, community choice aggregator, or electric cooperative.

Load Serving Entity (LSE) Plan: An LSE's integrated resource plan; the full set of documents and information submitted by an LSE to the CPUC as part of the IRP process.

Load Serving Entity (LSE) Portfolio: A set of supply- and/or demand-side resources with certain attributes that together serve the LSE's assigned load over the IRP planning horizon.

Long term: More than 5 years unless otherwise specified.

Loss of Load Expectation (LOLE): A metric that quantifies the expected frequency of loss-of-load events per year. Loss-of-load is any instance where available generating capacity is insufficient to serve electric demand. If one or more instances of loss-of-load occurring within the same day regardless of duration are counted as one loss-of-load event, then the LOLE metric can be compared to a reference point such as the industry probabilistic reliability standard of "one expected day in 10 years," (e.g., an LOLE of 0.1.)

LSE: Load Serving Entity

MASH: Multifamily Affordable Solar Housing

Maximum Import Capability: A California ISO metric that represents a quantity in MW of imports determined by the CAISO to be simultaneously deliverable to the aggregate of load in the ISO's Balancing Authority (BAA) Area and thus eligible for use in the Resource Adequacy process. The California ISO assess a MIC MW value for each intertie into the ISO's BAA and allocated yearly to the LSEs. A LSE's RA import showings are limited to its share of the MIC at each intertie.

MDV: Medium Duty Vehicle

MMBtu: millions of British Thermal Units

MMT: million Metric Ton

MTR: 2023-26 Mid-Term Reliability

MW: Megawatts

MWh: Megawatt-hour

NEM: Net Energy Metering

Net Qualifying Capacity: Qualifying Capacity reduced, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the California ISO pursuant to the provisions of this California ISO Tariff and the applicable Business Practice Manual.

Non-Modeled Costs: Embedded fixed costs in today's energy system (e.g., existing distribution revenue requirement, existing transmission revenue requirement, and energy efficiency program cost).

Nonstandard LSE Plan: Type of integrated resource plan that an LSE may be eligible to file if it serves load outside the CAISO balancing authority area.

NOx: Nitrogen Oxide

O&M: operations and maintenance

OIR: Order Instituting Rulemaking

Ongoing CTC: Ongoing Competition Transition Charge

OOS: Out of State

OP: Ordering Paragraph

Optimization: An exercise undertaken in the CPUC's Integrated Resource Planning (IRP) process using a capacity expansion model to identify a least-cost portfolio of electricity resources for meeting specific policy constraints, such as GHG reduction or RPS targets, while maintaining reliability given a set of assumptions about the future. Optimization in IRP considers resources assumed to be online over the planning horizon (baseline resources), some of which the model may choose not to retain, and additional resources (candidate resources) that the model is able to select to meet future grid needs.

OSW: Offshore Wind

P^3: Procurement Portfolio Planner

PA: Program Administrator

PCC: Portfolio Content Categories

P&G: Potential & Goals

PCIA: Power Charge Indifference Adjustment

PDP: Peak Day Pricing

Planned Resource: Any resource included in an LSE portfolio, whether already online or not, that is yet to be procured. Relating this to capacity expansion modeling terms, planned resources can be baseline resources (needing contract renewal, or currently owned/contracted by another LSE), candidate resources, or possibly resources that were not considered by the modeling, e.g., due to the passage of time between the modeling taking place and LSEs developing their plans. Planned resources can be specific (e.g., with a CAISO ID) or generic, with only the type, size and some geographic information identified.

PM: Particulate Matter

PPA: Power Purchase Agreement

PRM: Planning Reserve Margin

Preferred System Plan (PSP): The Commission's integrated resource plan composed of both the aggregation of LSE portfolios (e.g., Preferred System Portfolio) and the set of actions necessary to implement that portfolio (e.g., Preferred System Action Plan).

Preferred System Portfolio: The combined portfolios of individual LSEs within the CAISO, aggregated, reviewed, and possibly modified by Commission staff as a proposal to the Commission, and adopted by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Preferred System Plan.

PSPS: Public Safety Power Shutoff

Pub. Util. Code: Public Utilities Code

PURPA: Public Utility Regulatory Policies Act of 1978

PV: Photovoltaic

QF: Qualifying Facility

QF/CHP Settlement: Qualifying Facility and Combined Heat and Power Settlement

Qualifying Capacity: The maximum amount of Resource Adequacy Benefits a generating facility could provide before an assessment of its net qualifying capacity.

R.: Rulemaking

RA: Resource Adequacy

RAM: Renewable Auction Mechanism

RCP: Representative Concentration Pathway

REC: Renewable Energy Credit

ReMAT: Renewable Market Adjusting Tariff

RFO: Request for Offers

RPS: Renewables Portfolio Standard

RSBA: Reliability Services Balancing Account

RSP: Reference System Plan

SABR: System Average Bundled Rate

SADR: System Average Delivery Rate

SASH: Single Family Affordable Solar Homes

SB: Senate Bill

SCE: Southern California Edison Company

SDG&E: San Diego Gas & Electric Company

SGIP: Self-Generation Incentive Program

SmartAC: Smart Air Conditioner Programs

SOMAH: Solar on Multifamily Affordable Housing program

SOx: Sulfur Oxide

SQL: Structured Query Language

Staff: CPUC Energy Division staff (unless otherwise specified).

Standard LSE Plan: Type of integrated resource plan that an LSE is required to file if it serves load within the CAISO balancing authority area (unless the LSE demonstrates exemption from the IRP process).

T&D: Transmission and Distribution

TACBA: Transmission Access Charge Balancing Account

TMNBC: Tree Mortality Non-bypassable Charge

TO: Transmission Owner

TOU: Time-Of-Use

Transmission Planning Process (TPP): Annual process conducted by the California Independent System Operator (CAISO) to identify potential transmission system limitations and areas that need reinforcements over a 10-year horizon.

TRBA: Transmission Revenue Balancing Account

TSB: Total System Benefit

TWh: Terawatt-hour

U.S.: United States

UOG: Utility-Owned Generation

V2G: Vehicle-to-Grid

VAMO: Voluntary Allocation Market Offer

VGI: Vehicle to Grid Integration

WECC: Western Electricity Coordinating Council

ZEV: Zero-Emission Vehicle

VII. Appendix 1: Bundled Portfolio Optimization Tool

BPOT builds on the CSP framework by adding standard capacity expansion functionality. Like the CSP calculator, BPOT is an Excel-based model. The current version uses OpenSolver to drive the capacity expansion optimization.

Model Description

The BPOT is structured as a linear program where an objective function is minimized subject to a set operational and/or policy constraints. In this instance, the model is given a specific bundled portfolio load forecast and existing set of non-emitting resources and asked to choose from a set of candidate resources the mix of new resources that minimizes total bundled generation and procurement costs while at the same time ensuring that the portfolio provides sufficient RPS and GHG-free generation to meet the state mandated RPS and clean energy targets, the IRP-mandated 2030 and 2035 GHG planning targets, and sufficient RA capacity to meet the bundled portfolio's RA requirement.

To run, the model needs, among other things, a defined set of candidate resources and an hourly energy price forecast that spans the study period. For purposes of the analysis the candidate resources were limited to those chosen at the system level by the RESOLVE model in the 30 MMT and 25 MMT cases. The model utilized the LCOEs from RESOLVE and all related assumptions including inflation rate, levelization period, discount rate, taxes, and financing. Similarly, the model used the hourly price forecast developed from the 30 MMT and 25 MMT RESOLVE model results (see Section 2 (Study Design)). The primary output of the model is the set of new resource additions (e.g., MW of resource capacity added in each year).

Model Components

<u>Objective Function</u>

The objective function is specified as the net present value of the annual portfolio costs over the study period. Annual costs include the costs of new resources added to the portfolio and expected spot market energy revenues over the study period (2023–2035).

<u>Constraints</u>

- RPS: Existing RPS-eligible + new RPS generation >= annual RPS target
- GHG-free: Existing GHG-free + new GHG-free generation >= annual GHG-free target
- System RA: Estimated Existing resource September NQC + new GHG-free generation September NQC >= estimated annual September System RA requirement
- GHG Emissions: 2030-2035 (CSP model-based) LSE emissions <= specified GHG planning targets

<u>Other Key Inputs</u>

- Nominal LCOE by year for each new resource type

- Hourly CAISO energy price forecast spanning the study period
- Hourly generation shapes by resource type
- Hourly 2030 and 2035 CO_2 emission factors

Data Core

The model's primary data structure borrows directly from the CSP Calculator. For each year of the forecast, the following equations are specified for each hour:

Emissions are calculated as:

$GHG\ (MT) = \ Open\ Position\ (MWh)\ \times Emission\ Rate\ (\frac{MT}{MWh})$, where:

$$Open\ Position\ (MWh) = \ Bundle\ Load\ (MWh) - Existing\ GHG\ free(MWh) - New\ RPS\ (MWh) - New\ storage\ (discharge\ or\ charge)$$

Net Portfolio Costs (for the purpose of the optimization) are specified as the sum of New Resource costs and the Open Position market value

$$New\ Resource\ Cost\ (\$) = New\ Resource\ (MWh) \times LCOE\left(\frac{\$}{MWh}\right)$$

$$Open\ Position\ Marke\ Value\ (\$) = \ Open\ Position\ \ (MWh) * Energy\ Market\ Price\ \left(\frac{\$}{Mwh}\right)$$

The model chooses the mix of new RPS and storage resources (MW) that minimizes the net present value of total portfolio costs (new resource and open position) over the forecast horizon while ensuring that all RPS, GHG-free, system RA, and GHG emissions constraints are satisfied.

VIII. Appendix 2: PG&E DAC Programs

Tables 32 and 33 contain explanations of PG&E's DAC Programs, Pilots, Investments, as well as PG&E's Income Qualified Programs, Pilots, and Investments.

TABLE 32
DAC PROGRAMS, PILOTS, AND INVESTMENTS

	Category	DAC Programs and Pilots, and Investments
A	Clean Transportation	EV Fast Charge
	PG&E will pay for and build infrastructure from the electric grid to the charging equipment for public fast chargers, complementing state and privately funded initiatives. 25 percent of PG&E's approximately 234 planned EV fast chargers will be in DACs. PG&E will offer a significant rebate towards the purchase of fast chargers for customers based in these areas.	
B	Clean Transportation	EV Fleet
	PG&E will pay for and help customers install the electric infrastructure from the grid to the charging equipment at an estimated 700 fleet customer sites. PG&E will partner with school districts, transit agencies, delivery fleets and other business customers, which often rely on diesel for their fleets, which is a highly polluting fuel. 25 percent of the program budget will go towards investments in DAC and offer additional incentives for those sites, and for school and transit bus fleets that serve the general public. The program will also provide a rebate on EVSE costs to DACs up to a program total of $10 million.	
C	Clean Transportation	EV Charge 2
	PG&E's proposed EV Charge 2 program is an extension of the EV Charge Network and the EV Fast Charge programs and will support installation of L2 and DC fast charge charging ports at multi-family housing, workplaces, and public destinations. 50 percent of the program's infrastructure will be deployed in priority communities per Assembly Bill 841.	
D	Solar and Community Renewables	DAC – Single-Family Solar Homes
	The program will be available to low-income customers who are resident-owners of single-family homes in DAC. This will provide up-front financial incentives towards the installation of solar systems for low-income homeowners.	
E	Solar and Community Renewables	DAC-Green Tariff
	This program provides a 20 percent bill discount to customers in DAC who meet the income eligibility requirements for the CARE and FERA programs.	

TABLE 32
DAC PROGRAMS, PILOTS, AND INVESTMENTS
(CONTINUED)

F	Solar and Community Renewables	Community Solar Green Tariff
	This program will allow primarily residential low-income customers in DAC or in San Joaquin Valley pilot communities from the development of solar generation projects located in or near their communities and receive a 20 percent bill discount. The communities will work with a non-profit community-based organization or local government "sponsor" to organize community interest and present siting preference locations to the utility; the sponsor can also receive a bill discount for its efforts.	
G	Storage	WatterSaver
	Provides incentives for low-income customers and customers in DACs to electrify their water heating and shift the associated load to off-peak hours. The program launched in March 2022 and is expected to enroll 5,000-9,000 customers.	
H	Storage	SGIP Equity Budget
	Provides incentives for qualifying distributed energy resource systems – primarily batteries – installed on the customer's side of the meter that provide electricity for all or part of the customer's load. The SGIP Equity Budget and Equity Resiliency Budget prioritize energy storage projects in disadvantaged and low-income communities and in High Fire Threat Districts where PSPS have impacted customers.	
I	Workforce Education & Training	Connections
	PG&E leverages its Workforce Education and Training (WE&T) efforts to support awareness of green careers in DAC.	

TABLE 33
INCOME QUALIFIED PROGRAMS, PILOTS, AND INVESTMENTS

<table>
<tr><th></th><th>Category</th><th>Low Income Programs</th></tr>
<tr><td rowspan="2">A</td><td>Financial Assistance</td><td>CARE</td></tr>
<tr><td colspan="2">The CARE Program provides a monthly discount on energy bills for qualifying households throughout PG&E’s service area. To qualify for the CARE discount, a residential customer’s household income must be at or below 200 percent of Federal Poverty Guidelines or someone in the customer’s household is an active participant in other qualifying public assistance programs.</td></tr>
<tr><td rowspan="2">B</td><td>Financial Assistance</td><td>FERA</td></tr>
<tr><td colspan="2">The FERA Program provides a monthly discount on electric bills for qualifying households of three or more persons throughout PG&E’s service area. To qualify for the FERA discount, a residential customer’s household income must be between 200 percent plus $1 and 250 percent of Federal Poverty Guidelines, as required in D.04-02-057 and per Public Utility Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based on their economic need.</td></tr>
<tr><td rowspan="2">C</td><td>Financial Assistance</td><td>Relief for Energy Assistance Through Community Help (REACH)</td></tr>
<tr><td colspan="2">The REACH Program provides financial assistance for qualifying households throughout PG&E’s service area. To qualify for the REACH financial support, a residential customer’s household income must be at or below 200 percent of Federal Poverty Guidelines, must demonstrate an uncontrollable or unplanned change in their ability to pay their utility bill, must not have received REACH assistance within the past 18 months, and must have received a 15-day or a 48-hour disconnection notice.</td></tr>
<tr><td rowspan="2">D</td><td>Income Qualified Programs</td><td>ESA</td></tr>
<tr><td colspan="2">The ESA program provides income-qualified customers free energy-efficient home improvements that can help reduce their energy bills and improve their health, safety, and comfort. Services can include weatherproofing and attic installation, LED lighting, and refrigerator, furnace or water heater repair or replacement. The ESA program is a direct install program available to income-qualified customers in PG&E’s 48 counties. Since 1983 ESA has served over 2.1 million customers.</td></tr>
<tr><td rowspan="2">E</td><td>Income Qualified Programs</td><td>ESA Pilot Plus/ Pilot Deep</td></tr>
<tr><td colspan="2">ESA Pilot launching in 2022 with the goal of customers seeing deeper energy savings. A small percentage of participating customers will receive building electrification measures.</td></tr>
</table>

TABLE 33
INCOME QUALIFIED PROGRAMS, PILOTS, AND INVESTMENTS
(CONTINUED)

F	Clean Transportation	EV Educational Tools for DACs	PG&E also offers electric rate plans tailored for EV customers and rebates for EV purchases. PG&E continues to launch more educational tools and resources to help our customers overcome barriers to adoption.
G	Clean Transportation	Empower	PG&E's Empower EV offers a rebate for a residential charger, and in some cases panel upgrade, as well as tailored marketing, education, and outreach to meet the needs of low- and moderate-income customers with a focus on communities in Fresno, San Jose, and Brentwood/Oakley. PG&E will tailor Marketing, Education, and Outreach to best serve these communities with a focus on providing multi-lingual resources and leveraging a diverse set of marketing channels. PG&E is also partnering with a program implementer with close ties to the communities served to administer the Empower EV program.
H	Clean Transportation	Multi Family Home and Small Business Direct Install Pilot	PG&E will install low-power chargers (Level 1 and Level 2) at multifamily and small businesses with capacity on the panel within equity communities.
I	Clean Transportation	Pre-Owned EV Rebate	PG&E will offer a post-purchase rebate for pre-owned EVs. This is a $1,000 base rebate, with an additional $3,000 for income-qualified customers.
J	Solar and Community Renewables	MASH	Provides business solutions to offset the costs of installing new solar energy systems on multifamily affordable housing in California. MASH aims to improve the quality of housing, decrease energy use and lower costs for tenants. It also urges tenants to use high-performance solar systems that help protect California's environment.
K	Solar and Community Renewables	SASH	Provides solar incentives on qualifying affordable single-family housing.

IX. Appendix 3: Map of DAC Areas in PG&E's Service Territory

As illustrated in Figure 9 below, PG&E displays the DACs and tribal lands in its service territory that correspond to the definition used in this IRP:

[A] DAC shall be defined as any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, using the most recent version of the CalEPA's CalEnviroScreen tool.

FIGURE 9
MAP OF DISADVANTAGED COMMUNITIES IN PG&E'S SERVICE TERRITORY

X. Appendix 4: PG&E's Current Procurement Activity

PG&E's five (5) current RFOs are listed in Table 34 below. For a more comprehensive list of RFOs, including prior RFOs, please refer to PG&E's Wholesale Electric Power Procurement webpage.[109]

TABLE 34
PG&E PROCUREMENT SOLICITATION ACTIVITIES

	Program	Description	Website
A	Fall 2022 PG&E Solar Choice Solicitation	Purchase of Solar energy resources ranging from 0.5 to 20 MW	Fall 2022 PG&E Solar Choice RFO
B	Fall 2022 Regional Renewable Choice ("RRC") RFO	Purchase of community backed RPS eligible resources ranging from 0.5 to 20 MW	Fall 2022 RRC RFO
C	Fall 2022 Distribution Investment Deferral Framework (DIDF) RFO	Procure approximately 15 MW of DERs to defer distribution upgrade	Fall 2022 DIDF RFO
D	2022 Distribution Investment Deferral Framework (DIDF) Standard Offer Contract (SOC) Pilot	Procure In-Front-of-the-Meter DERs to defer distribution upgrades	2022 DIDF SOC Pilot
E	Mid-Term Reliability RFO - Phase 2	PG&E seeks resources to provide system-level net qualifying capacity (NQC). All resources will be expected to be considered incremental in counting towards PG&E's procurement responsibilities.	Mid-Term Reliability RFO - Phase 2

109 PG&E, Purchasing wholesale electric energy and capacity, <https://www.pge.com/en_US/for-our-business-partners/energy-supply/wholesale-electric-power-procurement/wholesale-electric-power-procurement.page?WT.mc_id=Vanity_rfo&ctx=large-business> (as of Oct. 26, 2022).