STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

FILED
02/21/20
01:29 PM

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 21, 2020

Agenda ID #18190
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 16-02-007:

This is the proposed decision of Administrative Law Judge Julie A. Fitch. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's March 26, 2020 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.2(c)(4)(B).

/s/ ANNE E. SIMON__________
Anne E. Simon
Chief Administrative Law Judge

AES:avs

Attachment

Decision **<u>PROPOSED DECISION OF ALJ FITCH</u> (Mailed 2/21/2020)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007

2019-2020 ELECTRIC RESOURCE PORTFOLIOS TO INFORM INTEGRATED RESOURCE PLANS AND TRANSMISSION PLANNING

TABLE OF CONTENTS

2019-2020 ELECTRIC RESOURCE PORTFOLIOS TO INFORM INTEGRATED RESOURCE PLANS AND TRANSMISSION PLANNING

Summary

This decision adopts an optimal portfolio, known as the Reference System Portfolio (RSP), to be used by all load-serving entities (LSEs) required to file individual integrated resource plans (IRPs) in 2020. The 2019-2020 RSP adopted utilizes the greenhouse gas (GHG) emissions target for the electric sector in 2030 set by the Commission in Decision (D.) 18-02-018 for the LSEs it oversees. The GHG target for the electric sector for 2030 is 46 million metric tons (MMT). This is within the 30-53 MMT range for the electric sector set by the California Air Resources Board pursuant to Senate Bill 350 (DeLeón, 2015). 46 MMT is equivalent to the 42 MMT target set in D.18-02-018, because it includes certain combined heat and power projects in the electric sector that were previously attributed to the industrial sector.

The 46 MMT 2030 GHG target for the electric sector keeps LSEs on the trajectory to meet the state's goal to supply 100 percent of retail electricity sales with renewable zero-carbon resources by 2045. It also already represents a disproportionate share of the overall state emissions reductions coming from the electric sector compared to other sectors. Finally, the 46 MMT target will likely become harder for the electric sector to achieve should electric loads increase more than previously expected in the coming decide, such as through more electrification of transportation and buildings. The Commission reevaluates this target every two years, and will reevaluate it again as we see more actual procurement by LSEs and can better gauge progress toward this goal.

The 2019-2020 RSP adopted in this decision serves as an optimal portfolio guide for LSEs required to file individual IRPs. The optimal portfolio, like the

previously adopted 2017-2018 RSP in D.18-02-018, includes a large amount of new solar, wind, and battery storage resources. Unlike the 2017-2018 RSP, however, this one does not include new geothermal resources, but adds out-of-state wind and pumped storage, or other long-duration storage, resources. The Commission will explore further in the procurement track of this or a successor proceeding how to go about ensuring that these additional resources, or others with equivalent attributes, are planned for and procured for the benefit of the sector as a whole.

In their individual IRPs, LSEs are required to show how their procurement to date, and planned procurement in the future, of electricity resources will help the state collectively meet this optimal portfolio and GHG target.

The decision makes available a GHG Planning Price, derived from the 2019-2020 RSP analysis, as well as a sensitivity to show the incremental costs and benefits of distributed energy resources, to the integrated distributed energy resource Rulemaking (R.) 14-10-003, for use in the Avoided Cost Calculator update being undertaken there. This decision also adopts minor modifications to the requirements for individual LSEs filing IRPs, and delegates to Commission staff to finalize the templates for this purpose by no later than April 15, 2020. The individual IRPs will be required to be filed no later than July 1, 2020.

For purposes of the California Independent System Operator's (CAISO's) Transmission Planning Process (TPP), this decision also adopts a reliability and policy-driven base case to be utilized to assess the need for transmission investments, based on the 2018 Preferred System Portfolio (PSP) adopted in D.19-04-040, with certain updates. The 2019-2020 RSP adopted in this decision varies significantly from the previous portfolios analyzed for TPP purposes and warrants transmission analysis first prior to moving to investment stage.

Therefore, this decision adopts the updated 2017-2018 PSP as the reliability and policy-driven base case, while offering the 2019-2020 RSP adopted in this decision as a policy-driven sensitivity case, to help analyze transmission needs for the future. A second policy-driven sensitivity case for use in the CAISO TPP is also adopted to test the transmission aspects of moving toward energy-only contracts for renewables in certain locations.

This decision also addresses a petition for modification (PFM) filed by the Alliance for Nuclear Responsibility on D.19-04-040 addressing the reasonableness of the costs of Diablo Canyon assigned to bundled customers, acknowledging the point of the PFM but ultimately denying it.

Two PFMs of D.19-11-016, one by the joint parties of California Environmental Justice Alliance, Sierra Club, Defenders of Wildlife, and the Public Advocates Office, and a second by GenOn Holdings, Inc., are also addressed and ultimately denied. While the Commission acknowledges the merits of the parties' arguments designed to discourage new natural gas plant investment and change the Commission's recommendations with respect to the once-through-cooling compliance deadline for the Ormond Beach Generating Station, respectively, neither requested modification to D.19-11-016 is a necessary action to accomplish the goals of the PFMs or those of the Commission.

This proceeding remains open.

1. Background

This decision addresses the first year of the two-year cycle for the integrated resource planning process adopted by the Commission in Decision (D.) 18-02-018. The first year consists of a staff-initiated development of an optimal electric resource portfolio, termed the Reference System Portfolio (RSP), which balances achievement of the greenhouse gas (GHG) target for the sector, ratepayer costs, and system reliability to give guidance for how the sector should be progressing over the next decade. The second year consists of consideration of the individual integrated resource plans (IRPs) of the load-serving entities (LSEs) under the Commission's purview, both individually and in aggregate, to form a Preferred System Portfolio (PSP). Both the RSP and the PSP are designed to be used by the California Independent System Operator (CAISO) in its annual Transmission Planning Process (TPP).

Our work on development of the 2019-2020 RSP began on November 29, 2018 with an Administrative Law Judge (ALJ) ruling seeking comments on inputs and assumptions for development of the 2019-2020 Reference System Plan. The November 29, 2018 ruling contained the inputs and assumptions recommended by Commission staff for the development of the scenarios to be analyzed for development of the RSP.

Comments in response to the November 29, 2018 inputs and assumptions ruling were timely filed no later than January 4, 2019 by the following parties: American Wind Energy Association, California Caucus (AWEA); Cal Energy Development Company, LLC (Cal Energy); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; CAISO; California Wind Energy Association (CalWEA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); Defenders of Wildlife (DOW); Form Energy, Inc. (Form Energy); GridLiance West, LLC (GridLiance); Hydrostor, Inc. (Hydrostor); Large-scale Solar Association (LSA); LS Power Development, LLC (LS Power); Natural Resources Defense Council (NRDC); Nevada Hydro Company (Nevada Hydro); Ormat Technologies, Inc. (Ormat); Pacific Gas and Electric Company (PG&E); Protect Our Communities Foundation (POC); Public Advocates Office of the

Commission (Cal Advocates); Range Energy Storage Systems, LLC (Range); San Diego Gas & Electric Company (SDG&E); Solar Energy Industries Association (SEIA); Sonoma Clean Power Authority (SCPA) and Marin Clean Energy (MCE), jointly; Southern California Edison Company (SCE); Southern California Gas Company (SoCalGas); Southwestern Power Group II, LLC (SWPG); he Utility Reform Network (TURN); TransWest Express, LLC (TransWest); Wellhead Power Solutions, LLC (Wellhead); and Women's Energy Matters (WEM);

Reply comments in response to the November 29, 2018 inputs and assumptions ruling were timely filed no later than January 16, 2019, by the following parties: Cal Advocates; California Community Choice Association (CalCCA) and MCE, jointly; California Hydrogen Business Council (CHBC); CAISO; Calpine; CEERT; CEJA and Sierra Club, jointly; CESA; Environmental Defense Fund (EDF); Green Power Institute (GPI); GridLiance; Hydrostor; LSA; LS Power; Middle River Power, LLC (Middle River); NRG Energy, Inc. (NRG); PG&E; POC; SCE; SDG&E; SEIA; TransWest; TURN; and Wellhead.

The next phase of 2019-2020 RSP development was the issuance of an ALJ ruling on February 11, 2019 seeking comment on proposed scenarios for 2019-2020 Reference System Portfolio. The ruling included scenarios proposed by Commission staff to be analyzed for the development of the RSP.

Comments in response to the February 11, 2019 scenarios ruling were timely filed no later than March 7, 2019 by the following parties: AWEA; CAISO; Cal Advocates; Cal Energy; California Large Energy Consumers Association (CLECA); Calpine; CalWEA; CEERT; CEJA and Sierra Club, jointly; CESA; Cogeneration Association of California (CAC); CHBC; Golden State Clean Energy (Golden State); GPI; GridLiance; Hydrostor; Imperial Irrigation District (IID); LSA; LS Power; Middle River; Nevada Hydro; NRDC; NRG; PG&E; POC;

Range; SDG&E; SCE; SoCalGas; SWPG; TransWest; TURN; Union of Concerned Scientists (UCS); Wellhead; and Western Power Trading Forum (WPTF).

Reply comments in response to the February 11, 2019 scenarios ruling were timely filed no later than March 15, 2019 by the following parties: Cal Advocates; Calpine; CESA; CHBC; Golden State; GPI; GridLiance; Hydrostor; IID; Middle River; POC; Sierra Club, EDF, CEJA, and NRDC, jointly; PG&E; Range; SCE; SDG&E; SoCalGas; Wellhead; and WPTF.

Another ALJ ruling, issued on September 20, 2019, sought input from parties on the filing requirements for LSEs in the development and submission of their individual IRPs for 2020. The ruling contained a staff proposal for what individual LSEs should be required to file in their individual IRPs and the manner in which the Commission would consider that information.

Comments in response to the September 20, 2019 filing requirements ruling were timely filed no later than October 14, 2019 by the following parties: Pico Rivera Innovative Municipal Energy, Bear Valley Electric Service, Redwood Coast Energy Authority, Just Energy Solutions, Inc., Apple Valley Choice Energy, Lancaster Choice Energy, Regents of the University of California, Rancho Mirage Energy Authority, and San Jacinto Power, jointly; Alliance for Retail Energy Markets (AReM); Bear Valley Electric Service (Bear Valley); Cal Advocates; CalCCA; CAISO; CESA; CEJA and Sierra Club, jointly; City and County of San Francisco (CCSF); DOW; GPI; Ormat; PacifiCorp and Liberty Utilities (CalPeco Electric), LLC (Liberty Utilities), jointly; PG&E; POC; SCE; SDG&E; Shell Energy North America (US), L.P. (Shell); Small Business Utility Advocates (SBUA); and TURN and the Center for Accessible Technology (CforAT), jointly.

Reply comments in response to the September 20, 2019 ruling on filing requirements were timely filed no later than October 25, 2019 by the following parties: AWEA; Cal Advocates; CalCCA; CCSF; DOW; GPI; PG&E; POC; SCE; SDG&E; Sierra Club and CEJA, jointly; and TURN.

On November 6, 2019, an ALJ ruling was issued seeking comment on the staff recommendation for the 2019-2020 RSP.

Comments were timely filed no later than December 17, 2019 by the following parties: 350 Bay Area; AReM; AWEA; Bay Area Municipal Transmission Group (BAMx); Cal Advocates; CHBC; CAISO; CalCCA; CESA; Calpine; CalWEA; CEERT; CEJA and Sierra Club, jointly; CCSF; CLECA; CAC; DOW; Eagle Crest Energy (Eagle Crest); EDF; Geothermal Resource Council; Golden State; GPI; GridLiance; L. Jain Reid (Reid); LS Power; Middle River; Nature Conservancy; Nevada Hydro; NRDC; Ormat; PG&E ; POC; Range; San Diego County Water Authority (SDCWA) and City of San Diego, jointly; SCE; SDG&E; SEIA, Vote Solar, and LSA, jointly; SoCalGas; SWPG; TURN; UCS; and Western Grid Development.

Reply comments were timely filed no later than January 6, 2020 by the following parties: AWEA; CHBC; CAISO; CalCCA; CESA; Calpine; CalWEA; CEERT; CEJA and Sierra Club, jointly; CCSF; Coalition for the Optimization of Renewable Development (CORD); DOW; Eagle Crest; GPI; GridLiance; Hydrostor; Middle River; Nature Conservancy; NRDC; PG&E; POC; Range; SCE; SDG&E; SEIA, Vote Solar, and LSA, jointly; SWPG; TransWest; TURN; UCS; Wellhead; and Western Grid Development.

2. Modeling Analysis and Results

Capacity expansion and production cost modeling were both utilized to develop the draft optimal electric resource portfolio for consideration in this proceeding. As in the prior cycle, the RESOLVE model was the capacity expansion model utilized, and Strategic Energy & Risk Valuation Model (SERVM) was used for production cost modeling. This section describes the work that was completed, as well as parties' inputs that were utilized to improve the process and analysis.

2.1. Inputs and Assumptions

The November 29, 2018 ALJ ruling seeking comments on inputs and assumptions for development of the 2019-2020 reference system plan included a large number of changes updated since the prior IRP cycle. Key changes included:

- Updating the load forecast assumptions to align with the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) demand forecast for 2018 (adopted by the CEC in February 2019).
- Updating the baseline resource assumptions to the more recent data available on existing and planned resources within and outside of the CAISO balancing authority area.
- Revising the capital cost assumptions and trajectories of solar photovoltaics (PV), wind, as well as other renewable technologies, to capture rapidly-declining technology costs.
- Revising capital cost assumptions for battery storage technologies to capture the rapidly-declining technology costs.
- Adding behind-the-meter (BTM) storage as a candidate resource that the model can select.
- Adding the ability to model economic retention of existing dispatchable thermal generation. This supersedes the blunt "40-year-age" retirement assumption that was sed in the previous IRP cycle.

- Incorporating post-2030 years into select modeling runs to reflect achievement of the Senate Bill (SB) 100 (DeLeón, 2018) 2045 goals.

One of the key assumptions driving results in the models in this round was the characterization of imports. In the prior IRP cycle, the CAISO import level that could count towards resource adequacy was set to the maximum import capability (MIC) determined by the CAISO annually. However, in this cycle, the CAISO import level that could count towards resource adequacy was set to 5 gigawatts (GW), an amount consistent with historical levels of firm resource adequacy contracting between non-CAISO generators and LSEs within the CAISO, primarily to account for the expected increasing pressure on available resources in the rest of the Western Electricity Coordinating Council (WECC) area to remain available to provide capacity locally rather than to the CAISO in general.

2.1.1. Comments of Parties

Since there were multiple rounds of informal and formal comments on assumptions to be used, most parties' concerns have been addressed in the results produced for purposes of the staff recommendation for the 2019-2020 RSP.

Still, some parties continue to have concerns about particular assumptions. A common concern was that the cost data for renewable generation utilizes the 2018 National Renewable Energy Laboratory Annual Technology Baseline. A 2019 version has been produced since analysis began in this round of IRP. In addition, there were particular complaints about solar and battery cost assumptions not aligning with market prices, and therefore representing higher costs than parties would have preferred.

A number of parties, including CESA, also lamented the lack of representation of gas/storage or solar/storage hybrid resources in the assumptions.

TransWest commented that transmission costs need to be updated.

With respect to battery effective load carrying capability (ELCC) assumptions, CESA, Eagle Crest, and POC all felt that further analysis should be performed to refine the battery ELCC curve before the next IRP cycle analysis. CESA, SEIA, and Wellhead all also were concerned that hybrid resources should be more directly considered, at the very least in the next IRP cycle.

Numerous parties were also concerned about the reduction in import limits for this IRP cycle, and how they were implemented both in the RESOLVE and SERVM models. This issue is discussed in more detail in later sections of this decision.

2.2. Scenarios and Sensitivities

The February 11, 2019 ALJ Ruling Seeking Comment on Proposed Scenarios for 2019-2020 Reference System Portfolio included plans for framing scenarios, main scenarios, and special studies. The framing scenarios used 2045 as the final study year, to inform scenarios for 2030 in light of 2045 goals. The main scenarios included three GHG limits for the electric sector: 1) 46 million metric tons (MMT), which corresponds to the 42 MMT target adopted by the Commission in D.18-02-018, with adjustments to align accounting for the emissions associated with combined heat and power (CHP) with the way the California Air Resources Board (CARB) accounted for them in its 2017 Scoping Plan analysis; 2) 38 MMT; and 3) 30 MMT.

For 2019-2020 RSP development, Commission staff began with the 46 MMT scenario, which corresponds to the 2030 GHG target established in

D.18-02-18. This case formed the "default" case. The 38 MMT and 30 MMT cases were analyzed as differences from the 46 MMT Default Scenario.

After presentation of the preliminary results of these cases at a public workshop on October 8, 2019, Commission staff made a number of minor improvements and corrections to the RESOLVE model. Those included limiting annual demand response buildout to a realistic annual level in the near term, and other small adjustments. To focus in on some of the nearer-term potential for reliability challenges, Commission staff reran the major GHG target scenarios to produce outputs for every year from 2020 to 2024, plus 2026 and 2030.

Commission staff also modeled an additional scenario designed to capture a combined set of assumptions that more closely approximated expected reality of electricity sector conditions. This new case, referred to as the 46 MMT Alternate Scenario, is a variation of the 46 MMT Default Scenario, with two changes: 1) an assumption that approximately half of the once-through cooling (OTC) natural gas-fired steam turbine units scheduled to retire at the end of 2020 are instead extended for three years (*i.e.,* through the end of 2023); and 2) some limitations on the annual buildout of solar capacity in the early years, to reflect what is likely a more feasible buildout scenario based on historical experience.

In addition, a number of sensitivity cases were run, to test the impact of changes in assumptions for certain individual variables. These included the following sensitivity cases: no new out-of-state transmission, low-cost out-of-state transmission, high-cost out-of-state transmission, offshore wind available, high solar photovoltaic cost, extension of the solar investment tax credit, high battery cost, paired battery cost, low resource adequacy imports, high resource adequacy imports, 2045 end year, a high-load sensitivity, full OTC extension, partial OTC extension, and early shed demand response availability. The 2045 studies included scenarios for high electrification, high electrification with new out-of-state transmission, high electrification with offshore wind available, high hydrogen, and high biofuels.

Commission staff also ran one other set of analysis to support development of avoided costs for use in estimating the cost-effectiveness of distributed energy resources (DERs). This analysis is presented in Appendix B of Attachment A to the November 6, 2019 ALJ ruling. A staff proposal is expected in the integrated distributed energy resource rulemaking to propose several updates to the Avoided Cost Calculator, used to forecast marginal avoided costs for cost-effectiveness analysis. One of the main changes likely to be proposed is to use values generated in RESOLVE modeling in this proceeding as inputs to the Avoided Cost Calculator.

2.2.1. Comments of Parties

Most parties were familiar with the three major scenarios modeled to develop the 2019-2020 RSP recommendation. Many comments were more focused on requesting particular sensitivities. Those included:

- More offshore wind (AWEA);
- Battery storage greater than 4 hours (CalCCA);
- Tax credit extensions beyond ITC (CalWEA);
- Higher load modifiers more in line with the state's "deep decarbonization" goals (CEJA/Sierra Club, SCE, SDG&E);
- Pumped storage in 2026 (Eagle Crest);
- More granular land-use data (Nature Conservancy);
- A greater range of GHG targets (Cal Advocates);
- More battery cost and performance variability (Eagle Crest, POC, SDCWA, City of San Diego);

- A higher import limit (POC);
- More conservative representative days and more accounting for varied energy and capacity benefits in different geographies (SDCWA and City of San Diego); and
- Modeling a 2045 end year to provide more context for the 2030 results (CAISO, UCS, SDG&E, SEIA).

2.3. RESOLVE Modeling

To conduct the analysis to support the development of the 2019-2020 RSP, like in the past RSP development, Commission staff used RESOLVE, a capacity expansion model designed to inform long-term planning questions around renewables integration. RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon, in order to identify least-cost portfolios for meeting specified GHG targets.

The RESOLVE optimization performed for the 2019-2020 IRP cycle covers the CAISO balancing area, including publicly-owned utility (POU) load within the CAISO. The model also optimizes dispatch at a coarse granularity, but not investment, outside of the CAISO.

Several RESOLVE model revisions and updates were made since the assumptions detailed in the November 29, 2018 ALJ Ruling on inputs and assumptions. These include updated assumptions to account for the increasing penetration of storage on the electric system. Similar to the addition of solar PV resources, as the penetration of battery storage on the system increases, the proportional capacity value of each increment of storage capacity decreases. The RESOLVE model was updated to account for this factor with declining ELCC values for battery storage.

Several updates from CAISO data were also added. Electrical zone boundaries were updated to match CAISO assumptions and candidate wind, solar, and geothermal resources were mapped to the new boundaries. RESOLVE was also modified to represent the multiple concurrent (or nested) limitations identified by the CAISO to deliver energy from renewable resource zones to load centers.

In addition, a major feature was added to allow RESOLVE to select economic retention of natural gas generation, instead of relying on the 40-year life assumption utilized in the prior IRP cycle.

Finally, RESOLVE was configured to run additional modeling years, including 2020, 2021, 2023, and 2024, in addition to 2022, 2026, and 2030. Capability was also added to consider timeframes out to 2045.

2.3.1. Comments of Parties

Parties to this proceeding have commented numerous times before on the use of the RESOLVE model for purposes of portfolio optimization. About half of the parties commenting in this round expressed general comfort with the model, while the other half had specific criticisms, up to and including recommending that the model is not appropriate for this use.

Serious concerns expressed include that the model should be ground-truthed for systematic underestimation of GHG emissions (CEJA, CEERT, and NRDC all express this view). Other concerns include the lack of consideration of resource diversity benefits, lack of multi-day dispatch capability, and that the model is too sensitive, not sensitive enough, too simplified, and too complex, especially as it relates to resource selection.

2.4. SERVM Modeling

Commission staff also used SERVM, which is a probabilistic system-reliability planning and production cost model. SERVM is designed to inform security-constrained planning, meaning the primary objective is to identify risk of there being insufficient generation. SERVM was configured to assess a given portfolio in a target study year, under a range of scenarios of future weather, economic output, and unit performance. SERVM performs hourly economic unit commitment and dispatch, and contains a zonal representation of the transmission system.

Several updates were made to SERVM for this cycle since the November 29, 2018 ALJ ruling on inputs and assumptions. Operating parameters for individual resources were updated based on the January 2019 CAISO MasterFile information and the WECC 2028 Anchor Data Set Phase 2, version 1.2. The electric demand inputs were updated to use the CEC's 2018 IEPR Update.

Commission staff performed a comprehensive update of the model's weather-normalized electric demand, and wind and solar generation hourly profiles. The hourly profiles represent 20 years of historical weather (1998-2017) which the model uses to consider uncertainty in future weather. The hydroelectric generation profiles were also updated to cover 1998-2017 patterns.

Commission staff incorporated an approximation of ambient temperature capacity derating for gas plants based on the Summer Net Qualifying Capacity (NQC) for these units. The ability for battery storage to provide spinning and load following reserves, in addition to regulation and frequency response, was also added. Forced and scheduled outage statistics were updated.

Finally, Commission staff developed scaling factors in SERVM to ensure that annual energy from BTM solar installations modeled in SERVM would match with the annual energy of installations projected in the CEC's IEPR.

2.4.1. Comments of Parties

As with RESOLVE, most commenting parties are familiar with SERVM from the prior IRP cycle and most expressed some measure of support for its use, albeit with numerous caveats. About half of the parties commenting also recommended supplementing the use of SERVM with other tools.

Major improvements recommended to SERVM included:

- Improving calibration with RESOLVE, especially in terms of dispatch and reliability assessment. This topic is more fully discussed in the following subsection;
- Checking intra-CAISO flows during stress hours and relocating new build if bottlenecks are found;
- Increasing the operational detail of CHP units to reflect the wide range of operating attributes and thermal benefits in the existing CHP fleet; and
- Checking for systematic underestimation of GHG emissions.

Other major concerns were that SERVM:

- Lacks sufficiently granular transmission system representation to capture locational effectiveness, so the Commission should move towards nodal model/security-constrained unit commitment and economic dispatch; and
- Lacks frequency regulation, stability, inertia, congestion, and second-to-second balance modeling.

Finally, at least one party recommended changing the loss of load expectation (LOLE) metric used for reliability to expected unserved energy (EUE) because the latter is better suited to further analysis to determine the appropriate tradeoff between increased reliability and ratepayer costs. Two parties also recommended adding a risk-based framework to address climate, fire, disaster, and/or resiliency issues.

2.5. Calibration

RESOLVE and SERVM were used together to develop an optimal portfolio of new resources to add to the existing fleet in the CAISO area to plan for achievement of long-term GHG reduction targets, while maintaining reliability, keeping costs reasonable, and accounting for uncertainty and expected energy market conditions. The role of the RESOLVE model is to select portfolios of new resources that are expected to meet policy goals, in particular the 2030 GHG emissions target for the electric sector, at least cost, and while ensuring reliability. The role of SERVM is to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE.

Commission staff spent several months calibrating RESOLVE and SERVM to ensure reasonable results. During the calibration process, staff sought to ensure that both models were using the same assumptions such as electric demand, fuel cost, generating resources, grid topography, and other inputs so that the models simulate the California electric system in a comparable way.

The models were calibrated iteratively, by developing portfolios in RESOLVE, feeding the portfolios into SERVM, and then validating the key operational results, including GHG emissions, curtailment results, and dispatch patterns. If results differed between models, changes were made to one or both until key outputs were consistent. More details of the calibration process can be found in the calibration slide deck presented at the October 8, 2019.[1] A calibrated RESOLVE model was then used to explore a wider range of sensitivities and scenarios.

[1] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442459770

The full set of RESOLVE inputs and assumptions were detailed in Attachment C to the November 6, 2019 ALJ ruling seeking comment on proposed reference system portfolio and related policy actions. The full set of SERVM assumptions are posted on the Commission's web site.[2]

2.5.1. Comments of Parties

Several parties made comments that the models needed to be more closely calibrated and/or assumptions were inconsistent. Those comments included recommendations for the following improvements:

- Improve consistency with regard to how each model constrains imports and characterizes the ELCC of wind and solar generation, and battery storage;
- Investigate inconsistent dispatch between models, especially the dispatch patterns and annual energy of baseload or dispatchable resources and unspecified imports, as well as renewables curtailment levels; and
- Investigate probably misalignment between the 15 percent Planning Reserve Margin (PRM) metric used in RESOLVE and the 0.1 LOLE metric used in SERVM.

2.6. Results

Attachment A to the November 6, 2019 ALJ ruling provides the detailed results of the major scenarios studied, including the 46 MMT Default Scenario, the 38 MMT, and the 30 MMT scenarios. The 46 MMT Alternate Scenario was also presented. Attachment B to the November 6, 2019 ALJ ruling contains further details of the reliability and production cost modeling conducted in SERVM to analyze the various scenarios and portfolios.

[2] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442461894

Table 1 below summarizes the CAISO area resource buildout results from RESOLVE for the various scenarios. The 2017-2018 PSP is also presented for purposes of comparison.

Table 1. Cumulative Incremental Resource Buildout in Key Scenarios (in megawatts (MW))

Scenario	Wind	Solar	Battery Storage	Pumped (Long-Duration) Storage	Geo-thermal	Shed Demand Response	Year
2017-2018	1,145	5,852	-	-	-	-	2022
PSP	1,145	5,852	187	-	-	-	2026
	2,246	5,916	2,104	-	1,700	-	2030
46 MMT	34	-	2,960	-	-	222	2021
Default	1,950	-	2,960	-	-	222	2022
	1,950	11,807	2,960	-	-	222	2023
	2,372	11,807	3,878	-	-	222	2024
	2,372	11,807	5,796	-	-	222	2026
	2,837	11,807	11,376	-	-	222	2030
46 MMT	34	2,006	624	-	-	222	2021
Alternate	1,950	4,006	624	-	-	222	2022
	1,950	6,006	1,336	-	-	222	2023
	2,550	6,006	3,759	-	-	222	2024
	2,550	6,006	5,193	-	-	222	2026
	2,837	11,774	11,384	-	-	222	2030
38 MMT	34	-	3,095	-	-	88	2021
	1,950	-	3,095	-	-	88	2022
	1,950	13,682	3,095	-	-	88	2023
	2,550	13,682	3,885	-	-	88	2024
	2,550	13,682	6,112	-	-	88	2026
	4,337	17,224	15,789	-	-	88	2030
30 MMT	34	-	3,095	-	-	88	2021
	2,392	-	3,095	-	-	88	2022
	2,392	14,873	3,095	-	-	88	2023
	2,992	14,873	3,757	-	-	88	2024
	6,453	14,873	6,525	85	-	88	2026
	8,279	20,826	19,084	85	-	88	2030

Commission staff focused in on the GHG emissions results under the different scenarios, also analyzing the results of the 46 MMT cases in SERVM. Table 2 below presents the results for the CAISO area only (the approximately 81 percent of the statewide electric sector emissions attributable to entities within the CAISO system).

Table 2. GHG Emissions Results in the CAISO Area (in MMT)

<table>
<tr><th>Planning Year</th><th>46 MMT Default</th><th>46 MMT Alternate</th><th>38 MMT</th><th>30 MMT</th></tr>
<tr><td colspan="5">RESOLVE Results</td></tr>
<tr><td>2022</td><td>41.6</td><td>39.6</td><td>41.5</td><td>41.2</td></tr>
<tr><td>2026</td><td>40.3</td><td>42.9</td><td>39.0</td><td>34.3</td></tr>
<tr><td>2030</td><td>37.9</td><td>37.9</td><td>31.1</td><td>24.3</td></tr>
<tr><td colspan="5">SERVM Results</td></tr>
<tr><td>2022</td><td rowspan="2">Not simulated</td><td>39.8</td><td colspan="2" rowspan="3">Not simulated</td></tr>
<tr><td>2026</td><td>44.5</td></tr>
<tr><td>2030</td><td>39.0</td><td>38.9</td></tr>
</table>

In terms of reliability assessment with SERVM, the preliminary results presented at the October 8, 2019 workshop indicated that these updated portfolios would be sufficiently reliable when modeled in SERVM. Commission staff considered sufficiently reliable to mean an LOLE of less than or equal to 0.1, which translates approximately to one day in ten years where the electric system would have to shed firm load due to insufficient generating capacity to service load and hold critical operating reserves.

However, when Commission staff were preparing variations on assumptions to analyze the 46 MMT Default and Alternate Scenarios, they discovered an issue when comparing results from the RESOLVE and SERVM models. While both models included a simultaneous import constraint for the CAISO area at the MIC level (approximately 11 GW), RESOLVE contained an additional constraint of 5 GW as the default assumption for imports that can be counted towards resource adequacy and meeting the planning reserve margin (PRM) requirement of 15 percent. SERVM, by contrast, did not have any similar additional constraint on imports. Thus, in assessing whether the electric system was sufficiently reliable, SERVM was relying on a larger set of potential imports than RESOLVE.

To further constrain SERVM to approximate RESOLVE's assumption that only 5 GW of imports can count towards resource adequacy, Commission staff added in SERVM a second CAISO simultaneous import limit of 5 GW that applied for all hours where gross electric demand is higher than the 95th percentile. This approximated the stressed hours of the year that the resource adequacy program is intended to cover.

When this additional SERVM constraint was added, the LOLE results exceeded 0.1 for 2022, 2026, or 2030 in the 46 MMT Default scenario. Table 3 below presents the LOLE results for this scenario.

Table 3. LOLE Results with Additional SERVM Import Constraint Added

Planning Year	46 MMT Default
2022	0.220
2026	0.108
2030	0.166

Knowing that the 46 MMT Alternate Scenario would be a likely option for the 2019-2020 RSP since it includes realistic assumptions about near-term buildouts, Commission staff focused its limited modeling resources on a more detailed study of this scenario using SERVM. Observing that the 46 MMT Default Scenario and the 46 MMT Alternate Scenario are similar in buildout and level of existing gas unit economic retention, staff predicted that SERVM simulations of the 46 MMT Scenario as-is from RESOLVE would also yield LOLE results that exceeded 0.1.

To ensure SERVM simulations that would demonstrate a 0.1 LOLE or better level of reliability for the 46 MMT Alternate Scenario, Commission staff estimated that 2,000 MW of generic effective capacity would need to be added to the portfolio. The 2,000 MW was added for the study years of 2026 and 2030, meaning it would be online by 2026. No extra capacity was added in 2022, since the 46 MMT Alternate Scenario included a partial extension of existing OTC units that should provide sufficient effective capacity in 2022. In this context, generic effective capacity can be understood to represent NQC for resource adequacy purposes, without regard to the type of resource providing the capacity. Such capacity could come from a number of potential sources: firm imports, batteries paired with solar, geothermal, demand response, or more economic retention of existing natural gas generation. The issue of the appropriate source of the capacity is an outstanding question parties were asked to comment on. But for reliability modeling purposes, when 2,000 MW of generic effective capacity was added to SERVM manually, the LOLE results given in Table 4 below were produced.

Table 4. LOLE Results with Additional SERVM Import Constraint Added Plus Addition of 2,000 MW of Generic Effective Capacity in 2026 and 2030

Planning Year	46 MMT Alternate
2022	0.070
2026	0.056
2030	0.016

While the portfolio to meet a 46 MMT GHG target produced by RESOLVE appeared viable, the reliability analysis produced by SERVM suggested that additional capacity would be needed to produce a functional electric system to inform the CAISO TPP.

3. Greenhouse Gas Target

The November 6, 2019 ALJ Ruling included the recommendation that the GHG target for the electric sector in 2030 be set at the 46 MMT level, which is the same level adopted for the 2017-2018 RSP for the last IRP cycle in D.18-02-018. This was chiefly for consistency with the prior cycle and also because the resource buildout associated with this level of GHG emissions target, with the large number of assumption changes since the previous cycle, resulted in a much larger number of new resources needing to be developed by 2030 than previously indicated in both the 2017-2018 PSP and the 2017-2018 RSP.

3.1. Comments of Parties

There was a strong division between parties over what GHG emissions target should be assumed for 2030. Calpine, GPI, Reid, Middle River, Cal Advocates, PG&E and SDG&E supported the use of the 46 MMT GHG target, though Cal Advocates was not supportive of the additional assumptions included in the 46 MMT Alternate Scenario and would prefer the 46 MMT Default Scenario.

AWEA, CESA, CEERT, CEJA, Sierra Club, Eagle Crest, NRDC, POC SDCWA, City of San Diego, SEIA, Vote Solar, LSA, TransWest, and UCS all supported a 30 MMT Scenario, because they argued it would put the state on track to meet the Senate Bill (SB) 100 (DeLeón, 2018) goals and is similar in buildout needed by the 2045 Framing Studies to meet the 2045 GHG goals.

CEJA and Sierra Club also would support 38 MMT as a backup, if 30 MMT is not adopted. SCE supported 38 MMT and included their own modeling results using different PRM and import assumptions, representing a portfolio that is similar to the 46 MMT portfolio identified by Commission staff.

3.2. Discussion

Commission staff recommended the 46 MMT GHG limit both because it is consistent with the limit adopted in D.18-02-018 and because it already represents a challenging portfolio to develop in less than a decade. For instance, the levels of new solar and battery storage represented in the portfolio constitute a very large investment requirement.

In addition, the actual load that will need to be served by the electric sector in 2030 is highly dependent on the uptake of vehicle electrification, as well as building electrification. With high levels of both types of electrification desirable to achieve the overall state emissions goals, if the state is successful in deploying a lot more electric vehicles and building appliances and systems, it may be even more of a challenge to meet the 46 MMT GHG emissions levels for the electric sector if additional electrification of vehicles and buildings occurs, beyond what has been previously assumed. However, the 46 MMT target remains within the range adopted by CARB and taking the load increases associated with electrification in mind.

The support from many parties of the 30 MMT GHG target level hinges on their concerns about reaching the 2045 emissions targets set by SB 100 and the predictions by many climate models seeking to restrict the amount of temperature rise and sea level rise on the planet due to concentrations of GHG emissions in the atmosphere.

With this in mind, Commission staff have run additional analysis of the 46 MMT Scenario, but with 2045 as the end year, in order to take into consideration the concerns of those parties about meeting the longer-term 2045 GHG goals, while maintaining reliability under higher expected electric loads. The high hydrogen, electrification, and biofuels scenarios studied in IRP were based on three PATHWAYS scenarios from the CEC's 2018 study, "Deep Decarbonization in a High Renewables Future."[3] The results of that additional analysis are discussed in more detail in the next section.

But for purposes of setting the GHG target, we note that one major finding of setting the end year for analysis at 2045 is that more of the natural gas capacity

---

[3] Available at: https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

is retained than in the previous RSP recommendation included in the November 6, 2019 ALJ ruling. This is chiefly because RESOLVE determines that it is more economic to retain natural gas capacity, particularly peaking capacity, for reliability purposes, than to retire the natural gas capacity and have to re-build it later after 2030, when electric loads are increasing dramatically due to expected electrification in other sectors.

Finally, we should note that the purpose of conducting IRP planning analyses in repeating cycles is to allow for updated analysis based on new information, new procurement, and new assumptions. The Commission has always intended to continuously revisit whether the 2030 GHG target set in the last IRP cycle is still the correct one. For this IRP cycle, on the basis of analysis already conducted and the additional analysis discussed in the next section of this decision, we conclude that the 46 MMT is still appropriate for our LSEs and will still be a challenge to achieve, but we reserve the right to revisit this conclusion in the next cycle of IRP analysis.

4. Reference System Portfolio

The November 6, 2019 ALJ ruling on the 2019-2020 RSP included the Commission staff recommendation that the 46 MMT Alternate Scenario be adopted as the RSP for the 2019-2020 IRP cycle. The 46 MMT Alternate Scenario included the additional import constraint implemented in SERVM in order to approximate the 5 GW resource adequacy import limit already included in RESOLVE. It also included the near-term limits on solar PV buildout, consistent with recent historical trends. Finally, the 46 MMT Alternate Scenario included an assumption of extension of half of the OTC capacity previously scheduled to retire at the end of 2020, for a period of three years. However, the 46 MMT

Alternate Scenario did not include in the baseline the 3,300 MW required to be procured in D.19-11-016.

4.1. Comments of Parties

Several parties, including Cal Advocates, particularly objected to not including the 3,300 MW of procurement required by D.19-11-016 in the baseline to develop the 2019-2020 RSP. A handful of other parties recommended using RESOLVE to identify the 3,300 MW identified for procurement specifically.

Several other parties, including DOW, CEJA and Sierra Club, SEIA, CalWEA, UCS, GridLiance, SWPG, and CAISO, objected to the inclusion of OTC extensions in the baseline, since the Commission has characterized these as an insurance policy, and certainly not the first choice for procurement. Therefore, these parties argued, inclusion in the baseline is inconsistent with the insurance notion. CAISO pointed out that the OTC extensions are still not confirmed, so they should not be assumed.

GPI commented that the recommended RSP should be based on a range of cases to cover uncertainty, rather than based on an overly-precise single scenario.

On the import assumptions, parties had mixed opinions on whether to use 5 GW as the import limit (CAC, AWEA, and CalWEA supported this level), the MIC level of 11 GW (UCS, Cal Advocates, CalCCA, and POC supported this level), or something else (Powerex supported a 3 GW import limit).

Several parties were also concerned that there may not be, and should be, consistent assumptions about particular power plants that represent dedicated imports in both models. Those plants are Hoover, Palo Verde, and Intermountain Power Plant, all historically used to serve California load even though they are located out of state. Both SCE and CAISO recommended that these plants be modeled as outside of the 5 GW import cap.

Several parties also suggested sensitivity testing in SERVM with different import limits, non-CAISO load levels, and non-CAISO portfolios to observe the impacts on California's ability to import power under a range of possible or likely different conditions on the Western grid in general. At least nine parties also felt that the staff's approximation of the 5 GW resource adequacy import limit in SERVM was inherently not a good representation of reality, and that the model should only have the MIC-based 11 GW limit, allowing it to choose an economic level of imports into CAISO since the model includes assumptions for and simulates economic dispatch of resources across the entire WECC region. AReM, for example, suggested that SERVM should not have any artificial constraints and should be run based on actual, West-side economic dispatch conditions, with staff analyzing the actual imports into CAISO during peak hours. Finally, six parties recommended aligning RESOLVE internally to impose the same import constraint in both the planning reserve margin and hourly dispatch parts of the model, instead of only imposing the additional import constraint on hourly dispatch in SERVM.

The CAISO voiced major concerns about the inclusion of 2,000 MW of generic effective capacity in the recommended RSP, pointing out that generic capacity does not have locations that can be mapped to busbars, making it unhelpful for transmission planning purposes. At least 20 other parties, representing the majority of viewpoints, also commented that this 2,000 MW should be modeled and identified in some way (using RESOLVE, SERVM, or both), with locations identified, in order to make the analysis meaningful and actionable.

The CAISO also had basic concerns about the level of battery storage included in the recommended portfolio, since the high level of storage has not yet been seen before in previous portfolios, and a robust methodology needs to be developed and agreed upon in order to map to busbars appropriately such a high volume of storage. CAISO was also somewhat concerned about the changing location assumptions of some of the renewables in the portfolio. Ultimately, CAISO expressed extreme doubt about the usefulness of utilizing the RSP for transmission planning purposes, because the impact of the portfolio on the system as a whole could be too unpredictable.

Related to the CAISO concerns about storage locations, CalCCA suggests that the IRP proceeding work on developing a process to identify and overlay local storage needs.

Several parties also expressed concern about the limitation placed on annual solar buildout in the 46 MMT Alternate Scenario. Solar was limited to 2,000 MW per year. Parties opposing this limitation included GridLiance, Nature Conservancy, SEIA, VoteSolar, LSA, and SWPG. Mainly, these parties pointed out that that annual level of build has been exceeded historically and they question why the modeling should artificially limit what could happen in reality. SCE, on the other hand, supported limiting the annual buildout of solar facilities.

4.2. Discussion

In response to the numerous comments from parties on the proposed 2019-2020 RSP, Commission staff ran some additional scenarios in both RESOLVE and SERVM, in order to address several of the concerns about the 46 MMT Alternate Scenario.

First, as discussed in Section 3.2 above, and as recommended by numerous environmental parties, Commission staff included explicit simulation of 2045, to see what possible 2045 load and resource conditions would suggest about the appropriate 2030 portfolio.

Second, in response to parties' concerns about not assuming OTC extensions that may or may not happen, the OTC extensions in the early years of the decade were removed from the assumptions. If any extensions are granted by the State Water Resources Control Board (Water Board), they will be available to perform the "insurance" function that the Commission intended, but will not be built into the baseline.

In a related manner, the 3,300 MW required by D.19-11-016 in the procurement track were also not included in the baseline, since although the amount of capacity is known, its characteristics are not. As a practical matter, some of the anticipated resources were already included in the 2019-2020 RSP baseline list of resources, and the resources actually procured by LSEs will be included in the baseline resources for the next RSP (2021-2022) evaluated by the Commission in the next IRP cycle. Leaving the 3,300 MW of capacity out avoids some amount of double-counting of resources. Assuming neither the OTC extensions nor the additional capacity also gives the analysis a chance to optimize for those needs that have already been identified by 2021 through 2023.

Next, as suggested by SCE and CAISO, the treatment of particular power plants that represent dedicated imports into CAISO was made clear and more consistent in both models. CAISO shares of Hoover and Palo Verde power plants, amounting to 1,457 MW, were included within the resource adequacy import limit of 5 GW set in RESOLVE, while Intermountain at 480 MW was left outside the limit. The CAISO shares of Hoover and Palo Verde represent resource adequacy contracts with Commission-jurisdictional LSEs and therefore fit within what the 5 GW limit represents, which is the historical levels of resource adequacy import contracting for LSEs. Intermountain, on the other hand, does not deliver to LSEs within Commission oversight or resource adequacy requirements, so is therefore not part of the 5 GW limit. Staff also revised the additional import constraint in SERVM to match RESOLVE's treatment of these particular power plants within its resource adequacy import constraint.

In addition, a number of more discrete model improvements were made based on updated information. The updated assumptions in RESOLVE were as follows.

The ELCC curve of battery storage was updated by Commission staff based on Astrape Consulting's revised ELCC analysis of 4-hour battery storage at varying penetrations given a 2022-based CAISO resource portfolio. This resulted in a slightly lower ELCC value for battery storage relative to the results from the November 6, 2019 ALJ ruling.

Solar resources located in Southern Nevada had their capacity factor amended to reflect their specific close geographic proximity to the California border. Arizona solar was previously considered outside of the CAISO, but has now been added to the resources balanced by the CAISO, removing the previously-associated transmission wheeling cost. Out-of-state wind capacity value was also added; it was not included in the previous scenarios run.

Finally, Commission staff ran a series of sensitivities to try to fill the 2,000 MW of generic effective capacity identified in the 46 MMT Alternate Scenario from November 6, 2019, by allowing RESOLVE to select the best way to specify the generic capacity, while still demonstrating reliability in SERVM.

The 2,000 MW "gap" filled by the additional of the generic effective capacity is likely at least partially explained by a few remaining calibration issues, which Commission staff will seek to rectify in future modeling. Those issues include:

- The inherently different nature of the two models resulting in SERVM's characterization of CAISO coincident peak load being higher than that of RESOLVE.
- The two models using slightly different load, wind, and solar hourly shapes, as well as ELCC values for wind and solar resources.

In SERVM, Commission staff also made modifications to improve consistency with RESOLVE, to the extent possible. The SERVM modifications were as follows.

First, the additional CAISO simultaneous import limit intended to parallel RESOLVE's 5 GW resource adequacy import limit was revised to be enforced during specific hours of the year, 5-10 p.m. in July through September, rather than during the highest gross electric demand hours The intent was to more robustly represent a constraint on imports during the periods meant to be covered by the resource adequacy program. As was the case before, for all other hours, the CAISO MIC is the simultaneous import limit in SERVM. As mentioned above, Commission staff also revised the additional import limit in SERVM to match RESOLVE's treatment of the CAISO shares of Hoover, Palo Verde, and Intermountain power plants in its resource adequacy import constraint.

In general, the additional constraint on imports during summer evenings implemented in SERVM is a strong driver of decreased reliability in SERVM results. Availability of imports may also significantly affect how the rest of the CAISO system dispatches resources around the import constraint, and could lead to changes in GHG emissions results. Setting this constraint at 5 GW represents a conservative assumption, based on the belief that non-CAISO entities in the future may be less able or willing to provide capacity to CAISO during late summer evenings because of their own native load needs, even though historically, actual imports during late summer evenings have not infrequently exceeded these assumptions, as suggested in the comments of several parties.

Given the conservativeness of setting the constraint at 5 GW and the many parties cautioning that it could lead to over-procurement and/or unnecessary ratepayer costs, Commission staff ultimately chose to relax the constraint by 1.5 GW, effectively setting the import limit at 6.5 GW during late summer evenings. Although the 6.5 GW figure now differs from RESOLVE's 5 GW resource adequacy import limit, the two models are by design different in how they assess reliability; constraining imports somewhat differently in each model is reasonable. Given the remaining known calibration issues mentioned earlier, it is reasonable to design model import constraints that have the effect of compelling RESOLVE to build more capacity assuming slightly less import availability than modeled in SERVM. This is an area that merits further modeling and analyses in future IRP cycles, as the load and resource conditions across the West evolve and affect the availability of resources to provide import capacity to the CAISO system.

Other modifications to SERVM included removal of the OTC extensions in the early years, consistent with RESOLVE, as well as small corrections to hourly load and load modifier shapes, specifically to fix a day-of-the-week alignment issue and a small error in the shapes representing default time-of-use rate impacts.

Finally, staff notes that there is a difference between the CAISO coincident peak demand assumptions in the two models. RESOLVE directly uses the IEPR demand forecast's CAISO coincident peak, while SERVM uses the IEPR demand forecast's Transmission Access Charge (TAC) area peaks to size its own set of hourly load shapes, resulting in an approximately 1.1 GW higher CAISO coincident peak in SERVM. This is one of the known calibration differences that is addressed by increasing the capacity requirements in RESOLVE to fill the 2 GW generic effective capacity gap identified in the proposed 2019-2020 RSP from November 6, 2019.

Another large driver of seemingly-different reliability results between the two models is the fact that a reserve margin of 15 percent, which is the assumption used as a constraint for building capacity in RESOLVE, does not necessarily equate to a 0.1 LOLE determined to be the acceptable reliability level in SERVM. Particularly as the resource mix deviates considerably from historical observation where the system was primarily thermal generation, the amount of deviation to be expected between these two inherently different metrics is unknown. A higher reserve margin may be required to achieve equivalent reliability with a higher mix of intermittent resources on the system. In general, it is likely that a 0.1 LOLE in SERVM implies a reserve margin requirement that would be somewhat higher than 15 percent in RESOLVE in order to result in equivalent results. The results of SCE's 38 MMT analysis would seem to support this conclusion, since SCE had to increase the PRM assumption in order to produce a reliable portfolio in their analysis.

In addition, the annual solar buildout cap in RESOLVE was left in place, because it does not impact the total amount of solar chosen by 2030, and only affects the distribution of solar buildout in the intervening years. Given that the reality of actual procurement is likely to be different from the modeled outcome of solar built per year anyway, and the fact that the long-term buildout of solar remains about the same, this constraint was left unchanged.

With all of these updates and changed assumptions in mind, Commission staff re-ran RESOLVE and SERVM with the 46 MMT GHG constraint in 2030, with a 2045 end year, without any assumed OTC extensions in the early years, without 3,300 MW of additional capacity by 2022, with the RESOLVE resource adequacy import constraints, with the SERVM summer evening peak import constraints, and with 2 GW of additional capacity chosen by RESOLVE, to simulate filling 2 GW of generic effective capacity originally identified in the November 6, 2019 ruling analysis. These assumptions collectively represent the new recommended 2019-2020 RSP being adopted in this decision.

The resulting new resource buildout of the 2019-2020 RSP is contained in Table 5 below.

Table 5. New Resource Buildout of 2019-2020 RSP (Cumulative MW)

Resource Type	2020	2021	2022	2023	2024	2026	2030
Wind	-	34	1,950	1,950	2,737	2,737	2,837
Wind on New Out-of-State Transmission	-	-	-	-	-	-	606
Utility-Scale Solar	2,000	4,000	6,000	8,000	8,000	8,000	11,017
Battery Storage	152	2,453	2,453	2,453	3,299	6,127	8,873
Pumped (long-duration) Storage	-	-	-	-	-	973	973
Shed Demand Response	-	222	222	222	222	222	222
Natural Gas Capacity Not Retained	-	-	-	-	-	-	(30)

Notably, the new resource buildout identified in Table 5 includes additional solar resources in the earlier years, retains more natural gas capacity, and identifies a need for new wind resources on new out-of-state transmission by 2030, as well as roughly 1 GW of pumped storage, or other long-duration storage with similar attributes, by 2026. These results represent a more diverse portfolio that many parties were looking for in their responses to the November 6, 2019 recommended RSP.

Figure 1 below is a graphical depiction of the same resource buildout information.

Figure 1. Cumulative Buildout of New Resources in 2019-2020 RSP

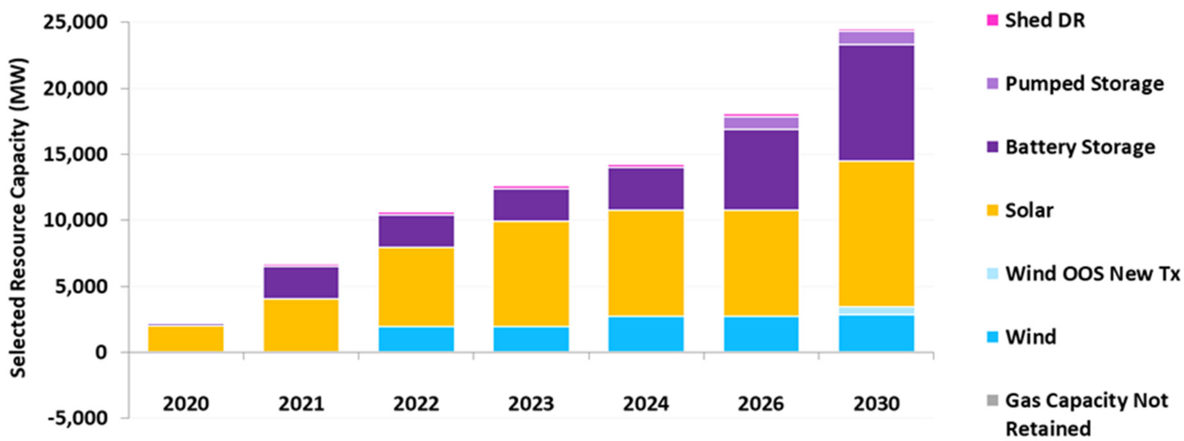

Table 6 below shows the total resource mix, including those resources assumed in the baseline, contained in the new 2019-2020 RSP. This will be important information for LSEs to keep in mind to ensure retention of necessary resources already or currently procured, such as wind, CHP, and thermal resources that are necessary to meet existing reliability and renewables portfolio standard (RPS) requirements in perpetuity.

Table 6. Total Resource Mix of New 2019-2020 RSP (Cumulative MW)

Resource Type	2020	2021	2022	2023	2024	2026	2030
Nuclear	2,935	2,935	2,935	2,935	1,785	635	635
CHP	2,296	2,296	2,296	2,296	2,296	2,296	2,296
Natural Gas	27,562	25,113	25,113	25,113	25,113	25,113	25,084
Coal	480	480	480	480	480	-	-
Hydro (Large)	7,070	7,070	7,070	7,070	7,070	7,070	7,070
Hydro (Scheduled Imports)	2,852	2,852	2,852	2,852	2,852	2,852	2,852
Biomass	903	903	903	903	903	903	901

Resource Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2026**	**2030**
Geothermal	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydro (Small)	974	974	974	974	974	974	974
Wind	7,357	7,490	9,406	9,406	10,193	10,193	10,293
Out-of-State Wind on New Transmission	-	-	-	-	-	-	606
Solar	16,310	18,766	20,887	22,887	22,887	22,887	25,905
Customer Solar	9,827	11,137	12,284	13,303	14,288	16,156	20,066
Battery Storage	1,846	4,614	4,717	4,887	6,073	9,065	12,138
Pumped (long-duration) Storage	1,599	1,599	1,599	1,599	1,599	2,573	2,573
Shed Demand Response	2,195	2,418	2,418	2,418	2,418	2,418	2,418
Gas Capacity Not Retained	-	-	-	-	-	-	(30)

Figure 2 below is a graphical depiction of the same information in the table above.

Figure 2. Cumulative Quantities of All Resources in New 2019-2020 RSP

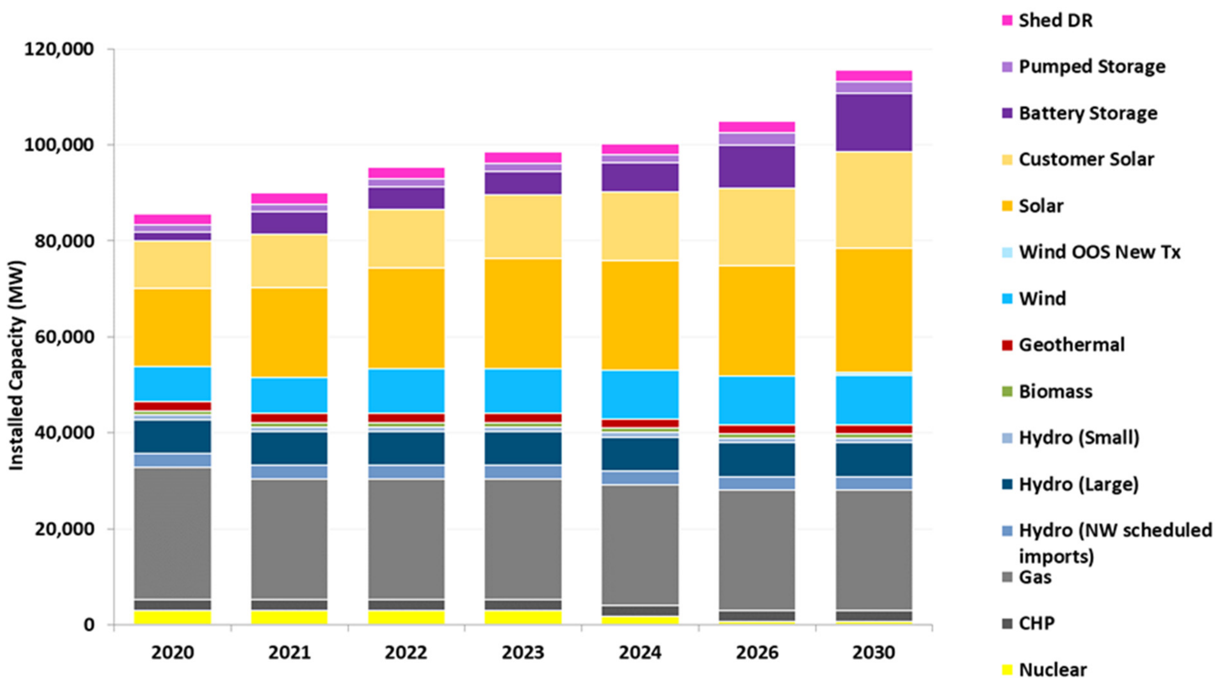

Table 7 below identifies several other key metrics associated with the new 2019-2020 RSP identified in this decision, including the GHG emissions, the PRM, and total resource cost and marginal GHG abatement cost in 2030.

Table 7. Key Metrics for New 2019-2020 RSP

Metric	2022	2026	2030
RESOLVE CAISO GHG Emissions (MMT)	37.7	41.0	37.9
SERVM GHG Emissions (MMT)	38.0	43.8	41.4
RESOLVE PRM	15%	15%	15%
SERVM LOLE (events per year)	0.032	0.113	0.108
SERVM LOLH (hours per year)	0.042	0.253	0.257
SERVM EUE (MWh per year)	19.2	292	597
SERVM Normalized EUE (percent of average annual energy demand)	0.0000078%	0.00012%	0.00023%
Total Resource Cost per year (in billion 2016 dollars)	$47.0	$44.5	$45.7
Marginal GHG Abatement Cost (in 2016 dollars per metric ton)	$17	$21	$130

There are several things to note in the above table. First, the GHG results from the two models diverge in 2030 by approximately 3.5 MMT at the CAISO level (or 4.3 MMT at the statewide level). This may be a result of differences in the way each model handles operational constraints, resulting in the observed differences in dispatch patterns, differences in hourly load, wind, and solar generation shapes as mentioned earlier among the known remaining calibration issues, or some combination.

These issues deserve further exploration in the next cycle of IRP, and also may later suggest the need for modeling a lower 2030 GHG emissions target in order to achieve the desired GHG reductions for the electric sector overall. At this stage, until we have better knowledge about the actual procurement and emissions characteristics of the resources chosen by LSEs, as well as the progress of other sectors toward electrification and decarbonization, we are not yet prepared to make a change to the 2030 GHG target. But as stated earlier, this is one of the many reasons for a cyclical approach to IRP, always updating our analysis with new information as it becomes available.

Commission staff also re-ran the criteria pollutants analysis that was included with the November 6, 2019 ALJ ruling, based on the new 2019-2020 RSP being adopted in this decision. Detailed results will be posted on the Commission's web site shortly.[4] In general, because of both the retention of more natural gas, as well as the identification of additional capacity, there were small increases (under 8 percent) in the amount of criteria pollutants emitted by the portfolio by 2030. The majority of the criteria pollutant emissions still come from biomass and combined cycle units. There was an increase in the average emissions from combustion turbines because of more starts of peakers. However, these changes do not result in changes to emissions in disadvantaged communities compared to the previous RSP recommendation from the November 6, 2019 ALJ ruling.

Another key metric is the LOLE produced by SERVM. While the results are not under 0.1 LOLE, they are very close and we are confident enough in the robustness of the results in this round to adopt this portfolio as our 2019-2020 RSP. Although the LOLE result produced is an exact number, the reality is that probability of loss of load occurs within a range. We find the results in Table 7 above acceptable for reliability planning purposes a decade out.

[4] Detailed analysis available at the following link: https://www.cpuc.ca.gov/General.aspx?id=6442459770

5. Greenhouse Gas Planning Price and Integrated Distributed Energy Resource Considerations

The 46 MMT Alternate Scenario recommended as the RSP in the November 6, 2019 ALJ ruling produced a stream of marginal GHG abatement costs culminating in a GHG abatement cost estimate of $114 per metric ton of GHG emission in 2030.

As mentioned previously, Commission staff also ran one other set of analysis to support development of avoided costs for use in estimating the cost-effectiveness of DERs. This analysis was presented in Appendix B of Attachment A to the November 6, 2019 ALJ ruling. A staff proposal in the integrated distributed energy resource rulemaking (R.14-10-003) issued on November 20, 2019 proposed several updates to the Avoided Cost Calculator, used to forecast marginal avoided costs for cost-effectiveness analysis. One of the main changes proposed is to use values generated in RESOLVE modeling in this proceeding as inputs to the Avoided Cost Calculator.

Thus, the new 2019-2020 RSP marginal GHG abatement cost in 2030 is relevant, and that number is $130 per metric ton.

5.1. Comments of Parties

Not many parties commented on this aspect of the February 6, 2019 ALJ ruling with the recommended 2019-2020 RSP analysis.

CEJA and Sierra Club recommended that the Commission develop an optimization that compares the cost of existing thermal resources, including air quality impacts, to the cost of replacement DERs and other renewable and GHG-free resources.

POC recommended that the Commission take the BTM inputs developed as part of the IEPR as a modeling sensitivity for DERs. They would prefer we use the "high" case developed in the IEPR for this purpose.

5.2. Discussion

The analysis provided in the "no new DER" scenario included in Appendix B of Attachment A of the November 6, 2019 ALJ ruling may need to be updated using the adopted 2019-2020 RSP portfolio in this decision. We expect that further analysis using IRP models may be undertaken in the integrated distributed energy resource (IDER) proceeding (R.14-10-003) in order to make the outputs as useful as possible for the Avoided Cost Calculator for DERs. We generally endorse the concept of this use of IRP modeling and its outputs, and point interested parties to the IDER proceeding, where further work may be undertaken. In addition, we explicitly adopt the 2030 GHG abatement cost price of $130 per metric ton, for planning purposes.

6. Procurement of Specific Resource Types

The November 6, 2019 ALJ ruling with the RSP recommendations also contained a series of questions related to the need for the Commission to initiate procurement activities for certain types of resources. Parties were asked to comment on the potential for overreliance on both solar and battery storage. Parties were also asked to weigh in on the reasonableness of the retention of the majority of the thermal fleet through 2030. Finally, parties were asked whether the Commission should take steps to begin development of transmission and/or generation to support geothermal development and pumped (long-duration) storage opportunities, as well as potentially offshore or out-of-state wind.

We note that these questions were asked prior to the analysis supporting the 2019-2020 RSP that we adopt in this decision, which now includes a need for approximately 1,000 MW of pumped (long-duration) storage by 2026 and 900 MW of out-of-state wind by 2030. The new RSP also includes the result that almost all (except 30 MW) of the thermal generation fleet will need to be retained through 2030, in order to support achieving the 2045 GHG goals for the sector.

6.1. Comments of Parties

Parties were generally split in their opinions about the proposed RSP's level of reliance on solar resources. Several parties, including CAC and Middle River, agreed with the November 6, 2019 ruling's characterization of the risks[5] and felt that these risks should be weighed prior to adopting any RSP for long-term planning. Numerous parties also commented that the portfolio should contain more resource diversity, including TransWest, GPI, SWPG, Eagle Crest, and UCS.

At least 20 parties expressed mild to strong concerns about the potential for overreliance on battery storage. Those parties included CAISO, Calpine, CalWEA, Eagle Crest, Geothermal Resource Council, GPI, GridLiance, Reid, Middle River, Ormat, Cal Acvocates, PG&E, Range, SDCWA, City of San Diego, SDG&E, SoCalGas, TransWest, UCS, and Western Grid Development.

A few parties also re-raised concerns that the cost assumptions for battery storage were too low. The CAISO and Calpine also noted that the costs associated with battery cycling and replacement were not fully incorporated into the modeling.

Several other parties, including CalCCA, CESA, CEJA/Sierra Club, NRDC, POC, SEIA, VoteSolar, and SCE, were bullish on battery storage and urged the Commission not to limit its development. CalCCA urged the Commission to

[5] *See* Section 6.1 of the November 6, 2019 ALJ ruling.

avoid directives that order premature storage deployment, because such an approach may prevent California from taking full advantage of technological advances and cost declines. SCE stood apart from other utilities by raising no concerns about reliance on battery storage, and even suggested adding more battery storage in early years to avoid bottlenecks in later years.

BAMx was opposed to the Commission making any procurement decisions to support out-of-state resources where new transmission would be required.

With regard to the retention of thermal resources, GPI, Reid, Middle River, Ormat, and the CAISO all supported the RSP outputs because of the demonstrated reliability needs of the portfolio. These parties mostly pointed out that natural gas is necessary as a backstop until new technology is developed.

Parties opposing the assumptions about retention of thermal resources through 2030 included CAC, which is concerned about retention of CHP resources being unrealistic due to their lack of a contractual path with the LSEs. CalCCA, CEJA, POC, and SEIA opposed thermal retention because the approach was too simplified and/or does not take into account criteria air pollutants in local areas, as well as statutory mandates on these topics. SCE specifically suggested that the Commission should conduct additional analysis to determine the specific thermal generation units that should be retained and what compensation should be provided to them to remain on the system.

Parties supporting the Commission taking concrete steps to begin the development of generation from geothermal resource areas, along with associated transmission, included CEJA, DOW, and Nature Conservancy. Parties opposing these steps included PG&E, SDG&E, CalWEA, GPI, Reid, Middle River, and TransWest, primarily because the RSP analysis did not demonstrate the need for geothermal.

Approximately 12 parties supported the Commission taking concrete steps to support the development of at least one pumped storage hydro project. These parties included AWEA, CESA, Calpine, CEJA, Sierra Club, Eagle Crest, Reid, Nevada Hydro, PG&E, SDCWA, City of San Diego, SDG&E, SEIA, and Vote Solar. CalCCA, CalWEA, DOW, GPI, LS Power, Nature Conservancy, Cal Advocates, POC, Range, and SWPG all opposed the initiation of procurement or development activities to support pumped storage facilities.

AWEA, TransWest, and LS Power suggested that the Commission should request that the CAISO study the need for out-of-state transmission resources to support wind development, with LS Power suggesting a specific work track of the IRP proceeding focused on this analysis. AReM, on the other hand, along with a handful of other parties, specifically opposed the Commission studying or initiating specific development activities for resources not otherwise identified as needed in the RSP or being actively pursued by LSEs already. They felt that the Commission should only direct procurement for specific resources if and only if the model chooses the resources in a robust manner and resource development is not already being initiated by LSEs. A few parties also suggested specific activities to improve resource assessment, prior to initiating development activities. For example, DOW and Nature Conservancy suggested expanding environmental and land-use screens to out-of-state and marina areas. AWEA suggested establishing a third Renewable Energy Transmission Initiative (RETI) type of effort to explore transmission needs.

GridLiance and SWPG suggested valuing resource diversity explicitly in the RSP analysis. CalWEA suggested vetting assumptions to enable offshore wind to be a default candidate resource type in the next IRP cycle. Calpine also suggested adding carbon capture and storage as a candidate resource type, with SoCalGas suggesting the addition of microgrids. 350 Bay Area also supported the inclusion of wholesale distributed generation as a candidate resource. CHBC supported the inclusion of long duration and seasonal storage solutions, such as hydrogen storage, in the RESOLVE model as candidate resources.

6.2. Discussion

As mentioned above, the 2019-2020 RSP we are adopting in this decision, as modified in response to numerous comments from parties, already identifies the need for pumped storage, or other long-duration storage with similar attributes, in the medium term (as soon as 2026) and out-of-state wind in the longer term (as soon as 2030). At this stage, while we are not ordering any new resource procurement with this decision, we do strongly encourage the LSEs to initiate procurement activities and planning activities within their individual IRP portfolios, to bring these resources to market. To facilitate this, we will take up the question of the concrete steps that the Commission can take to support the development of these resources, and potentially others as well, in the procurement track of this proceeding that will be ongoing, in parallel to the planning activities in this and subsequent IRP proceedings.

While we are ready to endorse and support the need for development of pumped, or other long-duration, storage and out-of-state wind in this decision today, we remain interested in further exploring the development of geothermal and offshore wind resources, as both continue to hold promise for meeting resource diversity and capacity needs for the future.

In addition, Calpine raises a good point with regard to continuing to keep carbon capture and storage as a possible technology in mind, particularly as we move toward our 2045 goals. Finally, we also intend to follow the progress with respect to microgrids and distributed generation occurring in other proceedings here at the Commission, and may incorporate learnings from those venues as suggested by SoCalGas and 350 Bay Area, respectively, as more information becomes available.

For now, we will require that each LSE, in its individual IRP, include discussion of the activities it is pursuing or intends to pursue to support the development of pumped storage, or other long-duration storage with similar attributes, and out-of-state wind resources in time for the 2026 and 2030 needs, respectively. These resources should be addressed in a separate section of each LSE's IRP, discussing the potential they see and the efforts they have undertaken or will undertake.

Additional steps from the Commission with respect to other resources, particularly those representing diverse attributes, including geothermal, will follow, in the procurement track of this or a successor proceeding.

7. Individual LSE Integrated Resource Plan Filing Requirements

On September 18, 2019, an ALJ ruling was issued seeking comment on filing requirements for the 2020 individual IRPs from LSEs. The ruling attached a staff proposal that included several modifications and clarifications to the filing requirements adopted in D.18-02-018, to ensure that the Commission has the right information in a useful form to assess and approve the individual IRPs, as well as aggregate them effectively to develop an appropriate 2019-2020 PSP.

The Filing Requirements staff proposal included the following recommended changes compared to the 2018 filing requirements:

- <u>Require all LSEs in the CAISO Balancing Authority Area (BAA) to file Standard Plans regardless of size, therefore</u>

eliminating the Alternative Plan: requesting contractual information from all LSEs within the CAISO will improve the aggregation process, especially due to the proliferation of small community choice aggregators (CCAs) which, in aggregate, may represent a significant share of load.

- Allow LSEs outside of the CAISO BAA a Non-Standard Plan compliance path: These LSEs (specifically, Liberty and PacifiCorp) may either file only the narrative template or submit IRPs prepared for other jurisdictions.
- Require all LSEs to only file Conforming Portfolios, therefore eliminating the Alternative Portfolio option: LSEs may only file plans that conform with 2019 Reference System Plan inputs and assumptions, assigned LSE-specific 2030 GHG emissions benchmark, and other requirements.
- Require all LSEs to use the IEPR assigned load forecast, including load modifiers: To support aggregation, the LSEs may not deviate from assigned annual share of the 2019 IEPR forecast. However, LSEs with load shapes significantly different from the IEPR CAISO system shape may propose different load shapes if the assigned annual energy volumes remain unchanged.
- Eliminate the GHG Planning Price to demonstrate achievement of the 2030 GHG planning target: No LSE used this option last cycle. Staff will continue to report the GHG Planning Price based on the Reference System Portfolio to support distributed energy resources valuation needs.
- Improve required reporting based on Integrated Resources Planning Standards: Staff identified a set of metrics that LSEs should meet based on the various statutory requirements described in PU Code Sections 454.51 and 454.52, including ensuring reliability, minimizing criteria pollutants with early priority for disadvantaged communities, amongst others. Staff expects these planning standards should clarify expectations for LSEs in developing their portfolios, standardize reporting across LSEs of different types and sizes, and facilitate staff production of the PSP.

- Improve functionality of the Clean System Power Calculator tool (formerly known as Clean Net Short or CNS Calculator) to support various existing and new or improved reporting requirements including costs, revenue requirement and reliability.
- Improve design and functionality of the Resources Data Template, including functionality to support proposed filing requirements, automated error checking, hybrid resource accounting, and standardization of contract types and generating units.
- Include new filing requirements adopted in D.19-04-040, including hydro generation risk management, resource shuffling, and Diablo Canyon Power Plant replacement.
- Improve reliability reporting requirements in LSE Plans by requiring LSEs to report reliability metrics to support reliability checks of the Aggregated Portfolios.

The following elements would remain unchanged from the 2018 requirements:

- Entities required to file IRPs include all IOUs, all CCAs with an approved implementation plan filed with the Commission as of the scheduled filing date, even if not yet serving load, and all ESPs that have filed a year-ahead load forecast for resource adequacy.
- Entities required to show proof of an exemption from the requirement to file an individual IRP include electric cooperatives whose energy sales do not exceed the three-year average of 700 GWh[6] and registered ESPs that are not serving California load in 2020.
- Requirements to describe methodology, modeling tools, and approach in the narrative portion of the IRP filing.
- 2030 GHG emissions reporting requirements (using Clean System Power (CSP) method);

[6] As provided for in Public Utilities Code Section 454.52(e).

- Reporting requirements on customers served in disadvantaged communities;
- Reporting requirements on criteria pollutants, though this requirement is now automated with the CSP Calculator; and
- Action Plan section of narrative template and including requirements from D.19-11-016.

In total, the requirements for filing of 2020 individual IRPs would consist of the following items required from each filing LSE:

- Narrative description of the IRP, based on the template developed by Commission staff;
- Resource data, using the template developed by Commission staff; and
- The output of a CSP Calculator file based on the LSE's proposed portfolio.

Entities not required to file an individual IRP would continue to file evidence of their exemption from the requirement.

7.1. Comments of Parties

Several parties commented on the idea that all filing LSEs be required to file a standard plan, regardless of size of load. Generally, CalCCA, Bear Vallley, and parties representing small LSEs objected to this concept. SDG&E supported it. CEJA also proposed that MJUs be required to include at least an executive summary that better aligns with the standard plan.

In response to the staff proposal that the provision for alternative portfolios be eliminated, POC, CESA, CEJA, CCSF, and SCE commented against the idea, arguing that LSEs need the chance to propose their own preferred portfolios. PG&E and SDG&E were ok with the concept, but wanted some flexibility to provide planning alternatives. GPI generally agreed with the staff proposal since it is the only way to ensure appropriate aggregation.

In response to the staff proposal that all LSEs be required to plan to procure their share of a resource or mix of resources that the Commission explicitly identifies as necessary for renewable integration, or report on and explain the variances, CalCCA objected that this requirement could be too limiting for LSEs.

SDG&E commented that a process is needed to update the final load the GHG benchmarks after adoption of the IEPR, considering some CCAs were not included there. SCE, SDG&E, POC, AReM, CalCCA, and CCSF strongly opposed the use of the IEPR to apportion load, because it would be inaccurate, unfair, and lead to distorted results and the inability to assess reliability. AReM was particularly concerned that LSEs with high load factors will be apportioned more than their fair share. SDG&E also argued that August should not be assumed to be the peak month, and that the IEPR forecasted peak month for each year should be used because it may vary in the future.

Parties supporting the staff proposal to allow LSEs to specify a development zone for near-term resources, but state no preference in the longer term included GPI, TURN, CESA, CEJA and Sierra Club, DOW, Cal Advocates, SDG&E, and SCE. POC, AReM, CCSF, PG&E did not object to this suggestion but thought it should go further, not to require geographic specificity except in the very near term.

On the topic of the narrative requirement around hydroelectric generation risk management, most parties felt that the staff proposal advances the issue, but more needs to be done. Parties generally supportive included CEJA, Sierra Club, CalCCA, PG&E, and SDG&E. GPI sought more detailed requirements.
Cal Advocates suggested that the CSP tool distinguish between in-state and out-of-state hydro contracts. POC argued that the LSEs should plan for the

"worst case" scenario for in-state drought. In reply comments, PG&E argued that "worst case" planning should come into play in reliability analysis, but LSEs should have flexibility about assumptions when analyzing the impact on GHG emissions.

On the staff-proposed narrative requirement around resource shuffling, several parties doubt whether the requirement will provide the necessary information to assess whether resource shuffling is occurring, including CEJA, Sierra Club, TURN, NRDC, and POC. GPI proposed minor modifications to the staff narrative. POC argued in reply comments that the TURN/NRDC proposal is not sufficient because it is qualitative and not quantitative. AWEA felt the TURN/NRDC proposal was impractical for LSEs to use, and that the Commission should first define resource shuffling and secondary dispatch.

On the staff proposal that the electric service provider (ESP) assessment be maintained at the aggregated level to maintain confidentiality, CEJA objected, arguing that local reliability issues may be masked. PG&E was neutral, but highlighted that the reopening of the direct access market may have an impact. SBUA asked how ESPs would share in the cost of correcting any resource shortfalls. And SDG&E suggested that a confidential version of the template be completed by ESPs so that confidential individual targets can be accounted for to enable assessment of each ESP's portfolio.

Parties also made numerous comments about the CSP Calculator. TURN argued that the tool should only be used to calculate an hourly pattern for energy-only deliveries, and should not be used to ascribe capacity benefit to those contracts. POC similarly argued that the tool should rely on LSE-provided load shapes because of the new hybrid resources entering the market that could have unique load shapes compared to historical resources.

SDG&E supported counting emissions from minimum thermal generation needs and recommended further including all hours where gas resources are operating at minimum power levels. CEJA and Sierra Club recommended that the tool provide granular criteria pollutant data by generator, resource type, and location.

7.2. Discussion

We adopt several changes to the filing requirements originally adopted in D.18-02-018, to ensure continuous improvement in the Commission's ability to review and assess the individual IRPs. The three aspects of required information to be filed by all LSEs remain the Narrative Template, the Resource Data Template, and the Clean System Power Calculator (replacing the Clean Net Short Calculator).

In the Narrative Template required from all LSEs, we agree with staff that LSEs should be required to file only Conforming Portfolios that conform to the Commission's requirements laid out in the 2019-2020 RSP. When individual LSEs filed Alternative Portfolios in the last cycle of IRP, it made it very difficult for us to assemble an aggregated portfolio for the CAISO system as a whole and evaluate it against the 2019-2020 RSP.

Another lesson learned from the previous individual IRPs was the need to require LSEs to distinguish more clearly between contracted and planned resources in their portfolios. The Resource Data Template has been updated to require LSEs to do so explicitly.

In addition, related to requirements adopted in D.19-04-040, sections in the Narrative Template have been added to require LSEs to address risks of reliance on hydroelectric generation, as well as requirements to address how the capacity of Diablo Canyon will be replaced.

The section of the previous template that addressed local needs has been removed, because in the previous IRP cycle, we generally found that this section did not provide any information that is incremental to what is already obtained as part of the resource adequacy requirements for LSEs. The Resource Data Template will still include information that will allow us to conduct a reliability evaluation for both local and system resources.

In the Resource Data Template, changes have been made by staff to more clearly delineate existing and new resources, as well as the status of contracting. In addition, it is important for the Commission to be able to assess risks associated with the portfolios proposed by LSEs. To that end, resource viability fields have been added or modified, related to delay risk, interconnection study status, permitting status, technical feasibility, resource sufficiency, and financing.

In order to assist with reconciliation between the procurement required by D.19-11-016 in the procurement track and any other procurement planned or undertaken by the LSEs, a flag has been added for those resource procured to comply with D.19-11-016.

In addition, several improvements have been made to the template to improve ease of use and quality checking.

Finally, in the CSP Calculator, Commission staff have made several improvements. The CSP Calculator now includes an automated approach to calculating criteria air pollutants associated with the LSE's portfolio. New functionality has been added to allow for claiming carbon-free energy from contracts with hydroelectric Asset-Controlling Supplier systems. Implied capacity (MW) values can also be automatically derived from energy (GWh) values for unspecified bundles of portfolio content category 1 eligible energy and renewable energy credits and large hydroelectric energy-only contracts, so that

LSEs can receive credit for the GHG-free attributes of those resources when the capacity values are unknown.

SERVM is now used as the basis for most hourly demand profiles, resource dispatch profiles, and emissions factors. By contrast, the 2017-2018 CNS Calculator included month-hour average dispatch and emissions profiles from the RESOLVE model.

Consistent with the Resource Data Template, entry fields in the CSP Calculator have been clarified to more clearly distinguish between existing and new resources.

We also carefully considered TURN and NRDC's joint proposal for more specific filing requirements regarding resource shuffling. On balance however, further analysis is needed regarding what data may be needed in addition to information from LSEs, the extent to which the Commission can use existing CARB Cap and Trade program rules and definitions, and the need to investigate a "credible counterfactual scenario" to assess the impact of LSEs' procurement of zero-GHG imports that would otherwise be serving out-of-state loads. Therefore, we will continue to explore these concerns but will not explicitly adopt the TURN/NRDC proposal at this time.

In response to comments primarily from AReM, a load-modifier toggle has been added for LSEs with load shapes that are different from the system average (e.g., a higher share of commercial and industrial load) to more accurately reflect their expected customer load.

New candidate resource types have been added, including two-hour storage, shed demand response, out-of-state wind, and offshore wind, along with associated resource hourly profiles.

Finally, emissions from all non-dispatchable in-front-of-the-meter CHP within the CAISO is automatically allocated to each LSE according to its load share, and BTM CHP emissions will be added to the system total by Commission staff during the portfolio aggregation process. Similarly, the Calculator has been updated to allocate a load-ratio share of system power generated during hours of renewable curtailment to each LSE.

With these changes, we adopt the Narrative Template, the Resource Data Template, and the CSP Calculator,[7] and delegate to Commission staff the tasks of finalizing and updating the materials for use by LSEs in filing their individual IRPs.

We also note also that the regular filing date for individual LSEs was required by D.18-02-018 to be May 1 of even-numbered years. That would mean that for this IRP cycle, individual IRPs would be required to be filed May 1, 2020. A delay is necessary this year in order to accommodate a number of moving pieces leading up to the filing of the individual IRPs, including activities emanating from D.19-11-016, the later-than-ideal production of the draft RSP, and the need to lock down load forecasts following the adoption of the IEPR. In addition, it is in the Commission's interests to make it possible for LSEs to file the highest quality IRPs possible. Therefore, the filing date is now being moved to July 1, 2020. To facilitate keeping this date for this IRP cycle, Commission staff will finalize any and all templates and materials by no later than April 15, 2020, and preferably earlier.

We anticipate introducing a new rulemaking docket soon to continue our IRP activities, and may consider revisiting the regular filing deadlines and

[7] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442459770

overall cycle schedules, as we consider the activities planned for the next cycle of IRP.

8. Portfolios for Transmission Planning Process

This section describes the proposals and adopted portfolios to be used by the CAISO in its TPP for 2020-21.

8.1. Reliability and Policy-Driven Base Cases

The November 6, 2019 ALJ ruling with the recommended RSP also proposed to utilize that portfolio as both the reliability and policy-driven base cases for the CAISO's 2020-21 TPP. Generally, the base cases, when analyzed in the TPP, can lead to direct transmission investment proposals to be brought to the CAISO Board for approval, with the construction and operation costs receiving cost recovery via insertion in the TAC.

8.1.1. Comments of Parties

Only two parties supported the staff recommendation to use the 46 MMT Alternate Scenario from the November 6, 2019 ALJ ruling as the reliability and policy-driven base cases for the TPP: Calpine and Reid.

Almost all other parties opposed this recommendation, for various reasons. SDG&E, BAMx, CalCCA, and GridLiance opposed due to the import assumptions being unrealistic and the insertion of the 2,000 MW of generic effective capacity. PG&E, CalWEA, GPI, Ormat, SEIA, and SWPG suggested that the holes in the portfolio be filled, and after that adjustment, the portfolio could be used as the base cases. SCE, CEJA, AWEA, and Range suggested that the 38 MMT or 30 MMT scenarios be used as the base cases.

The CAISO suggested not using any of the new scenarios at all for the base cases for TPP. Instead, they suggested utilizing the 2017-2018 PSP, with some adjustments. They gave two primary reasons. First, the 2,000 MW of generic capacity would have unknown locations on the grid, because the actual type of capacity is unknown. Therefore, this assumption cannot be utilized for TPP purposes. Second, the amount of battery storage in the portfolio in all of the RSP scenarios for 2019-2020 is very large compared to the 2017-2018 PSP, and a detailed methodology for mapping the battery storage to busbars has not been developed and vetted. Thus, the CAISO was very uncomfortable with the prospect of using this portfolio as a base case, potentially leading to certain transmission investment, when the locations of such a large amount of resources would be completely uncertain.

8.1.2. Discussion

For the reasons articulated by the CAISO, we find that it is premature to utilize either the 46 MMT Alternate Scenario recommended in the ALJ ruling of November 6, 2019 or the new 2019-2020 RSP adopted in this decision as the reliability or policy-driven base case for the TPP. The locations of too much capacity are too uncertain to jump directly to transmission investments at this stage with either of these portfolios. Therefore, we will continue to utilize, as recommended by the CAISO, the 2017-2018 PSP as the reliability and policy-driven base case for this cycle of the TPP.

By doing this, we are inherently separating the transmission investment decisions from the procurement direction given to the LSEs via the adoption of the 2019-2020 RSP. Once we have more real-world experience with how and where the LSEs are making investments toward the realization of the 2019-2020 RSP, we can then have higher confidence in the need for transmission in specific locations to support these generation and storage resources.

To continue making progress toward future TPP cycles, Commission staff will continue to work with the CAISO and the CEC to develop and vet a methodology for siting of the large amount of storage resources anticipated to be needed by 2030 according to the 2019-2020 RSP.

In addition, for this TPP cycle and the continuing utilization of the 2017-2018 PSP, our staff, in coordination with the CAISO and CEC, are making several updates and improvements since last year's PSP adoption.

Baseline resources now include the approximately 1.8 GW of wind and solar that have been added to the baseline due to development activity. Planned resources are then reduced by the new 1.8 GW of renewables now in the baseline.

Planned resources have also been reallocated to address misalignments between the 2017-2018 PSP and the criteria for effective busbar mapping set out in the Resource-to-Busbar Mapping Methodology Staff Proposal,[8] informal comments on that proposal, as well as party comments and replies on the November 6, 2019 ALJ ruling with the proposed RSP. 424 MW of Northern California geothermal resources with full capacity deliverability status have been reallocated to solar and battery storage resources, because the original selection of the geothermal resources did not meet the criteria for showing commercial interest or proximity to existing transmission capacity. In addition, 2.2 GW of capacity has been reallocated from the El Dorado substation to the Mohave substation due to violations of the criteria related to transmission capability limits and available land area. The new allocation assumes solar resources are available outside the specific Southern Nevada resource areas in the RESOLVE supply curve, in proximity to the Mohave substation. This assumption is supported by significant relevant capacity in the CAISO interconnection queue.

[8] Available at: https://www.cpuc.ca.gov/General.aspx?id=6442459770

Finally, all of the generic baseline storage in the 2017-2018 PSP is now linked to specific projects which can be mapped. A portion of the generic candidate storage in the 2017-2018 was made specific. And the additional generic storage amounts can be used to mitigate any transmission needs found during the TPP studies.

8.2. Policy-Driven Sensitivities

The November 6, 2019 ALJ ruling included two recommended portfolios to be studied as policy-driven sensitivities, which produce study results but do not lead to direct transmission investment, at least not immediately. Both sensitivities were recommended in order to develop transmission cost and congestion information, and would be performed with the 30 MMT scenario as the underlying portfolio. In general, the CAISO provides annually to Commission staff the transmission capability limits and upgrade cost estimates used as a direct input into RESOLVE for the IRP analyses. The CAISO is unable to provide transmission upgrade cost estimates for transmission zones that have not already required study in the TPP or the generation interconnection study processes under more aggressive GHG targets.

Currently, if a transmission zone does not have dispatchable resources, the CAISO assumes a 20 percent exceedance level of curtailment of new resources would be possible during summer peak load conditions, based on the current on-peak deliverability methodology, but does not provide an energy-only (EO) capability number. A zero EO limit is assumed for those areas in RESOLVE. Commission staff proposed to collaborate with the CAISO during the 2020-21 TPP cycle to incorporate less stringent EO limits than estimated in the past. These updated limits would be developed under the assumption that an increased amount of curtailment would be permitted in various transmission zones. These relaxed limits would allow RESOLVE to place more generation resources in transmission zones which have not been extensively studied, and in turn the CAISO would be better able to assess congestion in these areas, as well as transmission projects that could economically address the congestion. The purpose was to explore whether there are more economically-viable alternatives to assuming that new renewables beyond a certain level require full capacity deliverability status (FCDS). The congestion findings would flow into RESOLVE in the future to inform selection and location of new generation and transmission buildout.

To conduct this analysis, Commission staff recommended that multiple sensitivity portfolios be transmitted to the CAISO to produce information on congestion and transmission upgrade costs necessary to improve the co-optimization of generation and transmission in future RESOLVE runs. The two sensitivity cases proposed by Commission staff in the November 6, 2019 ALJ ruling were as follows:

<u>Policy-Driven Sensitivity 1</u>:

- The CAISO provides LEVEL 1 updated EO transmission capability estimates;
  - LEVEL 1 is defined as: An update to the previously-provided EO transmission capability estimates:
    - Provide EO estimates for zones for which the EO transmission capability estimates were previously marked “TBD” (*i.e.*, Westlands, Kern and Greater Carrizo, and Central Valley North/Los Banos);
    - Increase the EO transmission capability estimates by 10 percent for zones which were fully utilized (FCDS and EO) in the 2019-2020 TPP sensitivity portfolio

    #1, with the exception of zones for which significant known issues exist for adding more resources; and

    - Increase the EO transmission capability estimates for zones with "minor upgrades" (scope of work limited to inside an existing substation) by the same amount as the incremental capability provided by the upgrades.

  - New EO limits incorporated into RESOLVE allow the model to build new generation in more transmission zones. The selected resources are mapped to substations and the portfolio with busbar mapping is transmitted to the CAISO; and
  - The CAISO studies congestion impacts of additional new generation in more transmission zones.

Policy-Driven Sensitivity 2:

- The CAISO provides LEVEL 2 updated EO transmission capability estimates;
  - In addition to LEVEL 1 estimates, LEVEL 2 will increase the EO transmission capability estimates for zones with relatively low-cost upgrades by the same amount as the incremental capability provided by the corresponding upgrade;
- New EO limits incorporated into RESOLVE allow the model to build additional new generation in certain transmission zones. The selected resources are mapped to substations and the portfolio with busbar mapping is transmission to the CAISO; and
- The CAISO's assessment of this portfolio provides additional information on congestion in the transmission zones with further relaxed EO transmission capability limits.

The above 30 MMT scenario policy-driven sensitivity portfolios were designed to allow for the comparison of congestion impacts in each area, leading to better understanding of the costs and benefits of building new transmission.

In addition, it was expected that these sensitivities would produce updated transmission upgrade cost information if the CAISO found the need for new transmission under these information-only sensitivities.

8.2.1. Comments of Parties

In comments, three parties supported conducting both of the recommended sensitivities: PG&E, SDG&E, and CalWEA. BAMx, CalCCA, POC, SWPG, CAISO, and GridLiance supported conducting the first sensitivity only.

BAMx suggested a different sensitivity utilizing the CAISO's revised Deliverability Methodology, but the CAISO stated in their reply comments that they will be studying this in their generation interconnection process.

Numerous parties also commented in support of further stakeholder vetting of the busbar mapping results. CalCCA and SDG&E pointed to the efficiencies for TPP that could result, as well as benefits of better coordination between the Commission, CEC, CAISO, and LSEs. Parties were also concerned about the impact of a delay in transmitting the portfolios on the TPP process.

8.2.2. Discussion

At this stage, since we are transmitting the 2017-2018 PSP, with modifications, to the CAISO as the reliability and policy-driven base case for 2020-21 TPP, we will ask the CAISO to study the adopted 2019-2020 RSP as a policy-driven sensitivity. This will allow for a comprehensive transmission impact analysis of the high quantity of storage included in the 2019-2020 RSP. The storage in the portfolio was selected by RESOLVE to meet the 2030 GHG target at least cost, while ensuring reliability. Although it is impossible to predict exactly where on the transmission system this amount of storage will be built by 2030, due largely to the high mobility and flexibility of storage, analysis of the

2019-2020 RSP as a policy-driven sensitivity will help identify the potential implications of the storage for the transmission system. Commission staff will provide a full description of the methodology used to map storage to busbars in the updated version of the busbar mapping methodology to be released in March 2020.

In addition, for this cycle, we will ask the CAISO to study the Level 2 sensitivity case recommended by staff in the November 6, 2019 ALJ ruling, in order to test the congestion impacts related to FCDS vs. EO status. This sensitivity should give us additional information on co-optimization of generation and transmission to support the next round of IRP analysis. This sensitivity should help test whether there are areas in which the benefits of inexpensive transmission solutions can outweigh their costs, by reducing curtailment of renewables. The selection of the 30 MMT 2030 GHG target, with the resources mapped to substations assuming energy-only transmission limits that are relaxed in zones that are expected to offer relatively low-cost upgrade options.

The CAISO assessment of this portfolio will provide additional information on congestion and curtailment in the transmission zones with further relaxed energy-only transmission capability limits. This allows for comparison of congestion impacts in each area, leading to a better understanding of the costs and benefits of building new transmission. Depending on the results of this sensitivity, the CAISO may test upgrade options to mitigation renewable curtailment in certain zones in order to provide the upgrade information back to the IRP process in the next cycle.

9. Petition for Modification Related to Diablo Canyon

On October 1, 2019, the Alliance for Nuclear Responsibility (A4NR) simultaneously filed a petition for modification (PFM) of D.18-01-022 in the proceeding examining the retirement of the Diablo Canyon power plant (Application (A.) 16-08-006), and a PFM of D.19-04-040 in this proceeding.

A4NR's central argument in both PFMs is about doubting whether the Diablo Canyon power plant remains cost-effective for serving PG&E's bundled customers, with the large amount of departing or departed load from the PG&E system. A4NR bases its PFMs on information gleaned from a decision related to the power charge indifference adjustment (PCIA) (D.18-10-009). A4NR argues that the magnitude of the PCIA charges related to above-market costs of Diablo Canyon compelled it to file the PFM in A.16-08-006. Related issues are also being litigated in the PG&E General Rate Case (GRC).

D.19-04-040 is implicated only to the extent that it governs the manner in which PG&E is required to present its individual IRP, particularly as it relates to reliance on Diablo Canyon to serve bundled customers. In particular, A4NR would like D.19-04-040 amended to require PG&E to present scenarios for Diablo Canyon Unit 1 and Unit 2 that demonstrate that continued operation in each year of the 2020-2025 period is (a) cost-effective for PG&E's bundled load; (b) consistent with the principles articulated in the Commission's Procurement Policy Manual for least-cost/best-fit and utility-owned generation; and (c) wholly consistent with Public Utilities Code Sections 451 and 454(a).

9.1. Responses to Diablo Canyon PFM

WEM submitted the only response in this proceeding to the A4NR PFM. WEM broadly supports the PFM and argues that PG&E has not justified 2024 and 2025 as the optimal retirement dates for Diablo Canyon and therefore the Commission should make the requirements of PG&E requested by A4NR.

9.2. Discussion

From the perspective of this proceeding, we have been treating the retirement dates for the Diablo Canyon power plant as exogenous to our process. The timing for retirement of the plant has already been determined by the Commission in another proceeding. A4NR did not request that the Commission reevaluate the retirement dates. Further, for IRP purposes, the Diablo Canyon power plant is considered a system resource, because it is not needed for local reliability purposes. We have assumed that it will operate through the scheduled retirement of Unit 1 in 2024 and Unit 2 in 2025, as approved by the Commission previously in D.18-01-022. In the meantime, Diablo Canyon provides system reliability benefits, as well as GHG emissions benefits, that are needed for the electric system as a whole.

The issues related to cost reasonableness or cost allocation between bundled customers and departing customers to CCA and/or ESP load are not issues that we are analyzing in this proceeding. The costs of Diablo Canyon are included in the PCIA, which is appropriate for a system resource. The venues for arguments about the reasonableness of these costs are either the general rate case and/or the PCIA proceedings. And we do agree with A4NR that PG&E still has the burden to justify why its costs for operating Diablo Canyon during the next few years prior to retirement are just and reasonable. But this proceeding is not the venue for that justification.

In addition, as a practical matter, even if Diablo Canyon were to be determined not to be needed for system reliability, either for bundled customers or departing load customers, the planned retirement dates for both units are in the near future already, and LSEs are already planning for the current (near-term) timing expectations. Retiring Diablo Canyon units a year or two earlier may present a reliability challenge, since the power plant represents a large amount of capacity to be replaced in a short period of time.

For all these reasons, we deny the A4NR PFM in this proceeding.

10. D.19-11-016 PFMs

10.1. CEJA, Sierra Club, DOW, and Cal Advocates' PFM

On December 11, 2019, CEJA, Sierra Club, DOW, and Cal Advocates jointly filed a petition for modification (Joint PFM) of D.19-11-016, which emanated from the procurement track of this proceeding initiated in D.19-04-040 and required new procurement to meet electric system reliability needs beginning in 2021.

The Joint PFM requests that the Commission modify D.19-11-016 to clarify that "the only projects that utilize fossil fuel that may be allowed include the following narrow set of options: (1) energy storage projects that decrease GHG emissions and (2) projects that increase the efficiency or capability of existing units."[9] The parties filing the Joint PFM had advocated that the Commission prohibit any new projects utilizing fossil fuels from qualifying to meet the procurement targets set in the decision. The Joint PFM seeks to close what they characterize as loopholes that would allow new projects utilizing storage combined with natural gas, as well as augmentation of capacity at existing sites where natural gas is burned as a generation source. The Joint PFM also takes issue with the approval process authorized by D.19-11-016, stating that the advice letter process adopted will limit their ability to review and protest the

[9] Joint PFM, filed December 11, 2019, at 16.

procurement entered into by the LSEs. Thus, the Join PFM requests an application process be required for any facilities using fossil fuels.

The modifications requested by the Joint PFM would affect several parts of the text of the decision, as well as Finding of Fact 28, Conclusions of Law 21 and 22, and Ordering Paragraph 7.

10.1.1. Responses to CEJA, Sierra Club, DOW, and Cal Advocates PFM

Responses to the Joint PFM were filed by PG&E and SCE on January 10, 2020. SCE states that it agrees with the Joint PFM that new fossil fuel resources should not count toward the procurement requirement and does not take issue with the majority of the Joint PFM. SCE, however, argues that the Commission should not limit the eligibility of storage facilities that co-locate with existing fossil fuel facilities to those that reduce GHG emissions. SCE also prefers not to be required to file applications for contracts with existing facilities.

PG&E, in its response, does not disagree with the prohibition on new fossil fuel facilities, but argues that the Joint PFM is unnecessary because the intent of the decision was well understood. PG&E is also concerned that tightening the decision language could inadvertently prohibit procurement of resources that could meet both resource adequacy and resiliency objectives that are being addressed in its current request for offer (RFO) process, where certain hybrid resources may participate and/or biomethane may be utilized.

10.1.2. Reply of CEJA, Sierra Club, DOW, and Cal Advocates to PG&E's Response

CEJA, Sierra Club, DOW, and Cal Advocates jointly replied to PG&E's response on January 17, 2020. The joint parties argue that PG&E has never before objected to the exclusion of natural gas for procurement purposes nor proposed to utilize natural gas in this context. They also object to PG&E's

inclusion of natural gas and/or biomethane for its RFO on resiliency, arguing that the timeline set by PG&E there "can only be met with off-the-shelf gas generation," and that this amounts to a new "loophole" in the language of D.19-11-016. Accordingly, the joint petitioners argue that the Commission should: 1) reject PG&E's attempt to establish a new loophole; 2) reject all proposed procurement that does not meet the requirements of D.19-11-016 and state climate and air quality mandates and goals; 3) require PG&E to fully litigate its proposal in the Wildfire Mitigation Plan and Microgrid proceedings; and 4) grant their joint PFM.

10.1.3. Discussion

We generally agree with PG&E that the basic intent of the decision should already be clear, since it states that it agrees with the parties represented by the Joint PFM that new fossil fuel power plants should not be used to satisfy the requirements of the decision.

However, as most parties in this proceeding are aware, there are a lot of different configurations of electricity generation and storage projects; bright line prohibitions often cause more problems than they solve. The decision deliberately was not written with an outright prohibition on the use of natural gas in new facilities used to satisfy the procurement requirements, based on comments from Range,[10] detailing certain forms of emerging energy storage that may require fossil fuels to fuel their operations. Energy storage, by its very nature, is not a fossil-fuel-free resources, since even when it uses electricity from the grid, that energy is not 100 percent fossil-free. Nonetheless, the Commission has recognized energy storage as a preferred resource, since it helps facilitate

[10] *See* comments of Range on Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023, filed on October 31, 2019.

integration of renewables onto the electric grid. The intent of the decision was to discourage new fossil generation, while still allowing some creative projects that may utilize some amount of fossil fuels, but represents an environmental improvement over fossil-only resources.

Another example is the type of project PG&E references in its comments that may be utilized in its current open RFO, where certain technologies may enhance grid resiliency efforts, utilizing biomethane as a substitute for natural gas, while also providing resource adequacy benefits. As noted by the joint petitioners, PG&E's resiliency proposals should and will be litigated in other proceedings. But there may be other types of projects that have not yet been identified that may utilize some fossil fuels but still represent an improvement in terms of emissions reductions.

However, the parties to the Joint PFM are correct in the sense that we did not intend to encourage hybrid projects that are predominantly conventional in nature, such as a large peaker plant with a nominal amount of co-located battery storage, or other similar configurations. It is not possible, however, to remove the so-called loophole identified by the Joint PFM without also prohibiting potentially desirable projects such as compressed air energy storage or resiliency projects at substations utilizing biomethane.

Fortunately, the provisions of D.19-11-016 still require Commission consideration and approval of all of the projects used by the investor-owned utilities to satisfy their obligations under the decision. Thus, if the Commission or other parties see significant problems with the procurement choices of the investor-owned utilities (IOUs), the Commission has the option not to approve those contracts for cost recovery. Since the Commission does not separately review the procurement choices of the CCAs and ESPs, the language in the decision for those LSEs serves as policy guidance in keeping with our role to evaluate the long-term procurement and resource needs of the system as a whole.

For all of these reasons, we deny the Joint PFM of CEJA, Sierra Club, DOW and Cal Advocates.

10.2. GenOn PFM

On January 24, 2020, GenOn Holdings, Inc., owner of the Ormond Beach generating Station (Ormond Beach), filed a joint PFM of D.19-11-016 with the City of Oxnard, where Ormond Beach is located. In D.19-11-016, the Commission recommended that the Water Board extend the deadline for Ormond Beach's compliance with the OTC regulations by one year, to the end of 2021, citing concerns about community impacts.

In their joint PFM, GenOn and the City of Oxnard include a copy of their agreement to extend the life of the Ormond Beach plant by three years, while also providing significant benefits to the residents of Oxnard and surrounding communities, with plans for wetlands restoration, as well as demolition, decontamination, and removal of the power generating facility. This agreement between GenOn and City of Oxnard would extend the OTC compliance deadline to December 31, 2023, with the electricity revenues providing a source of funds to help with demolition and remediation. The joint PFM therefore requests that the Commission modify D.19-11-016 to seek a three-year OTC compliance extension instead of only one year from the Water Board.

10.2.1. Discussion

In D.19-11-016, the Commission made a recommendation to the Water Board to extend the OTC compliance deadline for Ormond Beach by one year.

As the decision acknowledged, the ultimate authority over OTC compliance deadlines rests with the Water Board.

We acknowledge the significant effort and positive outcome of the agreement between the City of Oxnard and GenOn that will provide benefits on both sides, and particularly to the City of Oxnard and surrounding communities. We commend both parties for reaching this agreement. Another benefit not specifically mentioned in the PFM is the fact that the Ormond Beach power plant is among the largest (approximately 1,500 MW) complying with OTC deadlines, and therefore having an additional two years of capacity available from this generator has a significant reliability insurance benefit to the electric system in the short term. This is another reason we support the agreement between GenOn and the City of Oxnard.

However, ultimately it is not necessary for the Commission to amend D.19-11-016 to change its recommendation on the Ormond Beach OTC compliance deadline, because the Statewide Advisory Committee on Cooling Water Intake Structures, the advisory committee to the Water Board on OTC issues, has already recommended that the Water Board accept the three-year extension negotiated by the City of Oxnard with GenOn. D.19-11-016 was rendered based on the best information available to the Commission at the time. Now that we are aware of the subsequent agreement between the City of Oxnard and GenOn, we are gratified to support the request for the three-year extension for OTC compliance for Ormond Beach at the Water Board in this decision. We therefore modify the Commission's recommendation that was included in D.19-11-016 by changing that recommendation in this decision, but decline to modify D.19-11-016 directly since it was simply a recommendation, which has now been superseded.

11. Assignment of Proceeding

Liane M. Randolph is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

Findings of Fact

1. The RESOLVE model is a capacity expansion model that, when run with key constraints such as GHG emissions limits, least-cost, PRM, and import limits, produces electricity resource portfolios that can be further analyzed for the CAISO area.

2. The SERVM model is a probabilistic system-reliability planning and production cost model that performs hourly economic unit commitment and dispatch, and contains a zonal representation of the transmission system. The SERVM model produces reliability and GHG emissions results when run with electric resource portfolios.

3. In order to produce a useful and appropriate 2019-2020 RSP, Commission staff needed to update numerous inputs and assumptions to the modeling analysis from the prior 2017-2018 RSP adopted in D.18-02-018, otherwise the results would have been outdated.

4. Because of the different purposes and operations of RESOLVE and SERVM, import constraints cannot be implemented in an identical manner in both models.

5. Ensuring sufficient capacity to meet a 15 percent PRM does not equate to reliability performance of 0.1 LOLE or less using the modeling assumptions from the 2019-2020 RSP development.

6. The three major GHG emissions scenarios run by Commission staff (30 MMT, 38 MMT, and 46 MMT) fall within the 30-53 MMT by 2030 range for the electric sector established by CARB pursuant to SB 350.

7. The 46 MMT scenario corresponds to the 42 MMT scenario 2017-2018 RSP adopted in D.18-02-018, after modifying the accounting treatment of BTM CHP to attribute its emissions to the electric sector, consistent with CARB's 2017 Scoping Plan analysis, instead of the industrial sector.

8. Commission staff, in the November 6, 2019 ALJ ruling, recommended a 46 MMT Alternate Scenario as the 2019-2020 RSP. The 46 MMT Alternate Scenario included two modified assumptions: an annual constraint on solar buildout and inclusion of half of the OTC capacity expected to retire at the end of 2020 to remain online through 2023.

9. In order to reach appropriate reliability metrics of LOLE under 0.1 in SERVM, the 46 MMT Alternate Scenario required Commission staff to add 2,000 MW of generic effective capacity.

10. Generic effective capacity inherently does not have a geographic location, and therefore it cannot be mapped for transmission planning purposes.

11. Limiting electric sector emissions to 46 MMT in 2030 would put the sector on the straight-line trajectory to achieving estimates of the necessary emissions in 2045 to reach the state's zero-emissions goals set forth in SB 100.

12. The Commission's recommended limit on electric sector emissions in 2030 can be and is designed to be revisited in each IRP cycle.

13. D.19-11-016 required procurement of 3,300 MW of system resource adequacy resources that should be online by the middle of 2023.

14. The Hoover and Palo Verde power plants provide resource-specific imports and should be included in the import limit specified in RESOLVE for purposes of analyzing the 2019-2020 RSP.

15. Limiting the annual buildout of solar resources in RESOLVE does not modify the ultimate amount of solar selected by the model by 2030.

16. Running RESOLVE with the changes in assumption above in response to parties' comments results in new resource buildout by 2030 of 2.8 GW of wind, 0.6 GW of out-of-state wind, 11 GW of utility-scale solar, 8.9 GW of battery storage, 0.9 GW of pumped (or other long-duration) storage, and 0.2 GW of shed demand response, with effectively all natural gas power plants retained.

17. If baseline resources are included, the total state buildout under the new 2019-2020 RSP assumptions is given in Table 6 of this decision.

18. The new 2019-2020 RSP includes a new resource buildout that is more than 50 percent larger than the 2017-2018 RSP adopted in D.18-02-018.

19. The new 2019-2020 RSP portfolio in RESOLVE produces a GHG abatement cost in 2030 of $130 per metric ton.

20. The new 2019-2020 RSP portfolio in RESOLVE includes pumped storage resources, or other long-duration storage resources with similar attributes, by 2026, and out-of-state wind resources by 2030.

21. A diverse resource portfolio will help the state reach its 2030 and 2045 GHG goals in a reliable and least-cost manner.

22. Templates produced by Commission staff for individual IRPs, resource data, and GHG emissions will assist the Commission in reviewing and aggregating the individual IRPs and assembling a quality PSP.

23. Transmission identified in the CAISO reliability base case and policy-driven base case will result in investment receiving cost recovery if approved by the CAISO Board, whereas policy-driven sensitivity cases are more for study purposes, producing cost information to feed into further analysis.

24. There is too much geographical uncertainty associated with the capacity identified in the 2019-2020 RSP adopted in this decision, particularly with respect

to battery storage, to use the 2019-2020 RSP as the reliability and policy-driven base case for the CAISO TPP this year.

25. Several updates and improvements to the 2017-2018 PSP are reasonable if it continues to be utilized for CAISO TPP purposes, including updates to the baseline resources, updates to the locations of some generation delivering to particular substations, and updates based on commercial interest in the CAISO interconnection queue.

26. The Commission determined the retirement dates for Diablo Canyon in D.18-01-022.

27. Diablo Canyon is a system resource adequacy resource.

28. PG&E is still required, in the appropriate proceedings, to demonstrate cost reasonableness of Diablo Canyon.

29. D.19-11-016 prohibited the construction of new natural-gas-only resources on new sites to meet the procurement needs identified, but did not prohibit new resources that use some amount of natural gas as part of hybrid configurations.

30. The City of Oxnard and GenOn Holdings, Inc. have mutually agreed to request a three-year extension to the OTC compliance deadline for the Ormond Beach Generating Station.

Conclusions of Law

1. The RESOLVE model continues to produce results useful for consideration of an RSP for IRP planning purposes and for use in the CAISO TPP.

2. SERVM continues to produce results useful for consideration of an RSP for IRP planning purposes and for use in the CAISO TPP.

3. The RESOLVE and SERVM models were iteratively and appropriately calibrated sufficient for the Commission’s reliance to produce the 2019-2020 IRP cycle analysis of an RSP.

4. It was appropriate to make the following updates to the inputs and assumptions for 2019-2020 RSP modeling analysis:

    (a) Updating the load forecasts to align with the CEC's IEPR forecast adopted in 2019.

    (b) Updating baseline resource assumptions.

    (c) Revising capital cost assumptions for all technologies, as available.

    (d) Adding BTM storage and certain energy efficiency measures as candidate resources to be selected by the RESOLVE model.

    (e) Revising the ELCC values with increasing penetrations of battery storage.

    (f) Updating electrical zone boundaries and including multiple concurrent (or nested) limitations identified by the CAISO to delivery energy from renewable resource zones to load centers.

5. It is reasonable for RESOLVE to include a 5,000 MW limit on resource adequacy imports including the Hoover and Palo Verde generators as a proxy for the likely tightening of import availability from other states across the West as they retire thermal resources and increase the penetration of GHG-free energy locally in their areas.

6. It is reasonable for SERVM to include some additional import constraints in peak load hours, as a proxy for the likely tightening of import availability, but because SERVM simulates operational impacts, constraining imports to the level in RESOLVE may be unnecessarily conservative. Instead, SERVM should appropriately have a slightly lower constraint on imports than RESOLVE, since the constraints are not identical.

7. It is reasonable for the Commission to adopt an electric sector GHG target in 2030 of 46 MMT at this time.

8. Analysis with a 2045 end year is appropriate to aid in selecting the 2019-2020 RSP.

9. Removal of any assumptions about extensions of OTC compliance deadlines is consistent with treating these as "insurance" and not primary procurement options in the baseline.

10. The exact nature of the 3,300 MW to be procured according to the requirements of D.19-11-016 is not yet known and therefore should not be included in the baseline for 2019-2020 RSP analysis purposes.

11. Commission staff's analysis of a new 2019-2020 RSP recommendation, in response to comments of parties, as described in this decision, and adding the additional 2 GW of capacity in RESOLVE, represents a reasonable portfolio for LSEs to collectively plan for by 2030.

12. The new 2019-2020 RSP new resource buildout will be a challenge to procure and build by 2030, as it represents an approximately 30 percent increase in wind capacity, a more-than doubling of solar capacity, a tripling of battery storage capacity, and a doubling of pumped storage, or other long-duration storage, capacity compared to current levels.

13. It is reasonable to utilize a "no new DERs" scenario included in Appendix B of Attachment A to the November 6, 2019 ALJ ruling with the recommended RSP, along with the GHG abatement cost of $130 per metric ton in 2030, as inputs to an update of the Avoided Cost Calculator in the IDER proceeding (R.14-11-003).

14. The LSEs should be required to detail in their individual IRPs their plans for procuring pumped storage resources, or other long-duration storage resources with similar attributes, and out-of-state wind resources.

15. The Commission should, in the procurement track of this proceeding, continue to consider steps required to develop and procure not only the resources identified in the 2019-2020 RSP, but also potentially additional geothermal and offshore wind resources, or other resources designed to bring diversity to the portfolio.

16. The Commission should delegate to Commission staff the tasks of producing the following items for LSEs to assist in preparation of their individual IRPs: a Narrative Template, a Resource Data Template, and a Clean System Power Calculator.

17. Public Utilities Code Section 454.52(e) provides for exemptions from filing IRPs for small electric cooperatives whose three-year average load does not exceed 700 gigawatt hours. Cooperatives should be required to file evidence of their qualification for this exemption.

18. The Commission should require all LSEs serving load within the CAISO BAA to file Standard Plans regardless of size.

19. LSEs serving load outside of the CAISO BAA (Liberty Utilities and PacifiCorp) should be permitted to file non-standard plans.

20. All LSEs should be required to file Conforming Portfolios that adhere to the assumptions used to form the 2019-2020 RSP.

21. The individual IRP filing deadline should be moved to July 1, 2020 for this IRP cycle.

22. The Commission should utilize the 2017-2018 PSP as the reliability and policy-driven base case, with updates as described in this decision, to forward to the CAISO for purposes of its 2020-21 TPP.

23. The Commission should forward the 2019-2020 RSP adopted in this decision to the CAISO as a policy-driven sensitivity for its 2020-21 TPP.

24. A second policy-driven sensitivity case based on the 30 MMT by 2030 Scenario, testing the impacts of energy-only deliverability status on congestion costs, should also be forwarded to the CAISO for its 2020-21 TPP, which should lead to better understanding of the costs and benefits of building new transmission .

25. Commission staff should continue to design and vet with parties methodologies for busbar mapping of generation and storage resources for the next round of IRP analysis and CAISO TPP study.

26. The Commission should consider cost reasonableness and cost allocation issues associated with Diablo Canyon outside of the IRP proceeding.

27. The October 1, 2019 A4NR PFM of D.19-04-040 should be denied.

28. The Commission should discourage investment in predominantly fossil-fueled resources with nominal amounts of other resource types (*e.g.,* storage) to satisfy the procurement needs identified in D.19-11-016.

29. The December 11, 2019 PFM of CEJA, Sierra Club, DOW, and Cal Advocates of D.19-11-016 should be denied.

30. The January 24, 2020 PFM of GenOn Holdings of D.19-11-016 should be denied as unnecessary, but the Commission should support the joint request of GenOn and the City of Oxnard for a three-year OTC extension for the Ormond Beach Generating Station at the Water Board.

O R D E R

IT IS ORDERED that:

1. The Commission adopts the greenhouse gas emissions target for the electric sector of 46 million metric tons in 2030, within the range for the sector established by the California Air Resources Board. The Commission applies this target to the investor-owned utilities, community choice aggregators, electric

service providers, and electric cooperatives under its purview for the integrated resource planning process.

2. The Commission adopts a Reference System Portfolio as defined in Decision 18-02-018 for the 2019-2020 Integrated Resource Planning (IRP) cycle represented by the electricity resources included in Tables 5 and 6 of this decision. All load-serving entities required to participate in the Commission's IRP process shall prepare their individual IRPs with this optimal electric resource portfolio for the year 2030 in mind, and describe their procurement activities designed to realize this portfolio.

3. The Reference System Portfolio identified in the RESOLVE model and adopted by this decision, along with a "no new distributed energy resources" scenario and a Greenhouse Gas Planning Price of $130 per metric ton in 2030, is made available to the integrated distributed energy resource Rulemaking 14-10-003 for use in valuing distributed energy resources and modifying the Avoided Cost Calculator in that proceeding.

4. The Commission delegates to Commission staff to maintain and provide, via emails to the service list of this proceeding and posting on the Commission's web site, up-to-date versions of the following items, by no later than April 15, 2020 for this cycle, to assist individual load-serving entities in preparing their individual integrated resource plans for Commission consideration:

(a) Narrative Template;
(b) Resource Data Template; and
(c) Clean System Power Calculator.

5. All load serving entities (LSEs) subject to the Commission's integrated resource planning (IRP) process shall file and serve their individual IRPs by no later than July 1, 2020. All LSEs serving load within the California Independent System Operator Balancing Authority Area must file a Standard Plan and a

Conforming Portfolio, as defined in Decision (D.) 18-02-018. PacifiCorp and Liberty Utilities may file a Non-Standard Plan. Any LSE claiming confidentiality of certain data shall also file and serve a motion to file under seal concurrent with their individual IRP, specifying the data requested to be kept confidential, with specific reference to D.06-06-066 and/or D.07-05-032 requirements.

6. Electric cooperatives claiming an exemption from filing an integrated resource plan in 2020 under the provisions of Public Utilities Code Section 454.52(e) must file evidence of this exemption no later than July 1, 2020.

7. All load-serving entities required to file a Standard Plan and Conforming Portfolio, as defined in Decision 18-02-018, shall detail in their individual integrated resource plans their plans and activities to procure pumped storage resources, or other long-duration storage resources with similar attributes, as well as out-of-state wind resources.

8. For purposes of the California Independent System Operator's Transmission Planning Process for 2020-21, the Commission requests the following scenarios be studied, and forwarded by Commission staff with detailed busbar mapping to the extent possible:

(a) The 2017-2018 Preferred System Portfolio adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in this decision, as the reliability base case and the policy-driven base case.

(b) The 2019-2020 Reference System Portfolio adopted in this decision as a policy-driven sensitivity.

(c) A portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion, as a second policy-driven sensitivity.

9. The October 1, 2019 Petition for Modification of Decision 19-04-040 of the Alliance for Nuclear Responsibility is denied.

10. The December 11, 2019 Petition for Modification of Decision 19-11-016 of the California Environmental Justice Alliance, Sierra Club, Defenders of Wildlife, and the Public Advocates' Office is denied.

11. The January 24, 2020 Petition for Modification of Decision 19-11-016 of GenOn Holdings, Inc. is denied; however, the Commission recommends approval of the three-year once-through-cooling compliance deadline extension for the Ormond Beach Generating Station to the State Water Resources Control Board, consistent with the agreement between GenOn Holdings, Inc. and the City of Oxnard.

12. This proceeding remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California.