BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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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 (Filed February 11, 2016)

OPENING COMMENTS OF PENINSULA CLEAN ENERGY AUTHORITY AND EAST BAY COMMUNITY ENERGY ON THE PROPOSED DECISION

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Pursuant to the Rule 14.3 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Peninsula Clean Energy Authority ("PCE") and East Bay Community Energy ("EBCE") offer the following comments on the proposed *Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle* ("Proposed Decision"). PCE and EBCE are members of the California Community Choice Association ("CalCCA") and support CalCCA's comments on the Proposed Decision.

East Bay Clean Energy and Peninsula Clean Energy value the Commission's role in statewide planning and look forward to working with the Commission to shape an effective and accurate planning process in which Community Choice Aggregators ("CCAs") will play a strong role in developing the solutions to transition California to a renewable energy system as rapidly as possible while maintaining reliability, affordability, and equity. This vision is grounded in our role as local mission-driven government agencies with local community control and accountability. CCAs are bound not only by State policy goals, including the GHG reduction and renewable resource goals of Senate Bill ("SB") 350; their missions squarely align with SB 350. For example, PCE's mission is to "reduc[e] greenhouse gas emissions and offer[] customer choice at competitive rates"[1] and EBCE's mission is to "provide cleaner, greener energy at competitive rates to [its] customers."[2] Many CCAs were created to meet or exceed California's GHG goals and are doing so affordably.

Accordingly, the Proposed Decision should be revised to:

1) adopt an iterative Integrated Resource Plan ("IRP") process that recognizes the important and complementary roles played by the local CCA governing boards and the Commission respectively;

2) find that the IRP process was proven feasible, but recognize that the output of the underlying models are too sensitive to variation in assumptions and data inputs to be considered reliable for use in making procurement decisions in this iteration;

3) defer any procurement mandates to subsequent IRP cycles; and,

4) defer adoption of the Reference System Plan ("RSP") as the Proposed System Plan ("PSP") until it is properly vetted.

I. THE INTEGRATED RESOURCES PLANNING PROCESS SHOULD ADOPT AN ITERATIVE MODEL TO ALLOW STATEWIDE GOALS BE MET THROUGH LOCAL ACTION GUIDED BY THE COMMISSION

The IRP process should facilitate an iterative collaboration between state agencies and local governments. In such a model, the Commission acts as statewide planning authority, while CCAs and other LSEs have both the duty and the authority to carry out their obligations to ensure the planning process achieves statewide goals.

To best meet statewide needs through the collective LSE IRPs, the Commission should embrace a long-term and iterative IRP process in which Commission planning and LSE procurement jointly ensure all needs are met. Such a collaborative process would develop a statewide assessment of successes and remaining needs and then allow load-serving entities ("LSEs") to revise their long-term plans accordingly. At minimum, the IRP process must

[1] https://www.peninsulacleanenergy.com/goals-and-policies/.
[2] https://ebce.org/.

correctly and accurately identify actual system needs, and then allow LSEs collectively and individually to address those identified procurement needs. Each subsequent cycle will reassess emerging needs in light of new conditions and LSE activities, and the Commission and LSEs will jointly adjust course to address those issues as they arise.

In such a collaborative and iterative approach to ensuring that identified needs are successfully met, when the collective IRPs fail to meet the statewide goals (either because LSEs are not meeting their Commission-identified individual needs or because collectively the LSEs are not meeting statewide needs), the first duty to develop a strategy to remedy the shortfall rests with the LSEs. Thus, the Commission upon determining a shortfall exists, would direct any LSE IRP that fails to meet Commission-identified needs to develop an improved strategy and resubmit an IRP that *does* meet the identified need. For collective needs that do not fall within the scope of any individual LSE's Commission-identified needs, the Commission may need to create a mechanism to coordinate among LSEs and to incentivize LSEs to meet identified system needs. For example, if the LSE best situated to meet the system need did so and received compensation for doing so, the iterative process would create a strong foundation for ensuring that identified system needs are met.

Only if such an approach fails or if an LSE refuses to develop strategies to meet identified needs would Commission-directed procurement followed by Commission-allocated costs to LSEs be required. Given that the timeframes for meeting system needs would span more than one planning cycle, there should be ample room both within a single IRP cycle and across IRP cycles for LSEs to develop and implement a successful IRP that will meet Commission-identified needs before the need for any Commission-directed procurement.

EBCE and PCE are concerned that by immediately establishing a procurement track in the next IRP cycle, the Proposed Decision fails to allow such an iterative approach appropriate for the IRP process. Only once the next cycle is complete will the Commission have a reasonable sense of how effectively the Commission and LSEs jointly can respond to needs identified in the planning process. After the Commission has determined individual LSE needs or system needs,[3] then all LSEs can again file IRPs to meet those individual and collective system needs. Such an iterative approach will ensure that the collective targets are met.

PCE and EBCE recognize that the IRP process — including the results of the analysis performed by the Commission regarding each of their individual IRPs as part of that process — provides them with a valuable report card as to how each entity is meeting its stated mission. Moreover, the Commission's efforts provide important feedback and guidance for the statutorily-delegated procurement activities of CCAs.[4] The Commission's comprehensive review of IRPs will assist CCAs with their statutorily-mandated procurement roles, while ensuring that the Commission meets its own separate statutory mandates under SB 350, if the Commission allows the IRP to be the iterative process envisioned in SB 350.

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[3] While it is appropriate to assess reliability impacts, the actual actions to address reliability issues are squarely in the Resource Adequacy ("RA") proceeding. Attempting to direct action to address shorter term reliability outside of the RA proceeding would violate SB 350's guidance that the IRP process not be duplicative of other proceedings. *See* Pub. Util. Code § 454.52(d).

[4] *See* Pub. Util. Code § 366.2(a)(5), which guarantees that each CCA program "is solely responsible for all generation procurement activities on behalf of the [CCA program's] customers, except where other generation procurement arrangements are expressly authorized by statute." Neither SB 350 nor any other statute "expressly" authorizes the Commission to order CCA programs to procure the resources identified by the Commission in its IRP process.

II. TO MEET THE GOALS OF SB 350, LOCAL CCA GOVERNING BOARDS AND THE COMMISSION SERVE COMPLEMENTARY ROLES IN AN ITERATIVE IRP PROCESS

This approach would also comport with the statutory structure balancing Commission's planning authority with CCAs' procurement authority. CCA governing boards and the Commission each have distinct roles and jurisdiction that complement one another to ensure that the overall IRP process achieves "a safe, reliable, and cost-effective electricity supply in California."[5] The Proposed Decision should be revised where it blurs the statutorily-mandated jurisdictional roles that the CCA governing boards and the Commission play within the iterative IRP process.

Section 366.2(a)(5)[6] specifies that the CCA governing board alone directs a CCA's procurement activities, except in limited circumstances expressly authorized in statute. Nothing in sections 454.51 or 454.52 directs CCA procurement. Thus, only an individual CCA governing board has the authority to direct an individual CCA's actual procurement.

While the Commission does not have authority to direct CCA procurement, the Commission does have significant and complementary authority to affect CCA planning and procurement activities through its statutorily-defined role under section 454.51(a) to ensure that the continued development of the entire California electric system is coordinated and efficient. Moreover, sections 454.51(c) and (e) provide the Commission with the authority to allocate the appropriate amount of the costs associated with filling any gap identified through its section 454.51(a) resource portfolio identification process to the individual CCAs that contributed to creating the gap. However, in lieu of paying those allocated costs, section 454.51(d) allows an

[5] Order Instituting Rulemaking, R.16-02-007, at 2 (Filed February 11, 2016).
[6] All statutory references are to the Public Utilities Code unless otherwise specified.

individual CCA to self-supply its portion of the gap, rather than accept an allocation of costs associated with Commission-directed procurement by electrical corporations to fill the gap.

III. THE FIRST IRP CYCLE HAS PROVEN THAT THE IRP PROCESS IS FEASIBLE, BUT ANY PROCUREMENT MANDATES SHOULD BE DEFERRED UNTIL THE IRP PROCESS IS REFINED IN THE NEXT IRP CYCLE

The first IRP filings and modeling results have proven that the IRP process is feasible. However, the Proposed Decision should be revised to defer any deficiency determinations requiring additional procurement until after the numerous data and methodological flaws described below can be successfully resolved in a subsequent IRP cycle. It would be inappropriate for the Commission to rely on an uncertain modeling result to lock California into significant and lasting procurement decisions.

Energy Division designed the 2017-18 cycle of the IRP process as a proof of concept test run "to demonstrate the feasibility of the proposed process."[7] Allowing for refinement of the proposed process is sensible because making major procurement or other regulatory decisions based on a single snapshot is unwise. For example, had major procurement decisions been made based solely on a hypothetical 2015-16 cycle, it would have failed to capture the impacts of wildfires, Pacific Gas and Electric Company's bankruptcy, the downgrading of IOU credit status, and the rapid emergence and success of CCAs.

The IRP process used in the 2017-2018 cycle must be refined before procurement mandates based on the IRP process would be appropriate. Specifically, the Commission should not use the 2017-2018 cycle to inform actual procurement decisions for the following reasons.

[7] Decision ("D.") 18-02-018, mimeo at 15.

A. The 2017-2018 IRP Cycle Failed to Produce Robust Quantitative Results

The Commission should recognize that the wide range of modeling estimates of GHG and reliability means that we do not yet have a reliable basis for clearly determining whether the aggregate portfolio meets statewide goals. The divergent results from modeling by CAISO, two Energy Division models, and Edison show that the model outputs are highly sensitive to changes in assumptions. For example, significant discrepancies in the quantitative results flow from the CAISO's PLEXOS model and the Strategic Energy Risk Valuation Model ("SERVM"). The HCP modeling results across the CAISO area range from 35.1 MMT (CAISO PLEXOS scenario 2 and 3,[8] with more accurate modeling of carbon intensity of NW resources) to 42.7 MMT in SERVM.[9] These results represent a 20% difference in absolute terms and an 8-fold difference in the estimate of the exceedance of the GHG target for the CAISO area. If the CAISO PLEXOS scenario 2 or 3 models are accurate, the aggregated Hybrid Conforming Portfolio is very nearly achieving statewide goals on the first iteration. This would call for a very different set of actions than if the SERVM model is more accurate. Before the Commission can meaningfully determine whether the aggregated LSE portfolio is or is not meeting statewide goals, different modeling approaches must be refined to hone overall estimates.

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[8] *See* CAISO PLEXOS model, scenarios 2 and 3, showing GHG emissions of 35.1 MMT based on more detailed gas dispatch assumptions and California Air Resources Board methodologies for estimating carbon intensities of Northwest imports. *(See* CAISO presentation "Reliability Assessment of the IRP Hybrid Conforming Plan" Presented January 7, 2019), http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/4.%20CAISO%202017-18%20IRP%20HCP%20Analysis_01032019.pdf

[9] *See* Energy Division SERVM model results, Energy Division Staff presentation "Proposed Preferred System Portfolio for IRP 2017-18: System Analysis and Production Cost Modeling Results" January 11, 2019 ("Energy Division Presentation"), at 89, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Attachment%20A_Proposed%20Preferred%20System%20Portfolio%20for%20IRP%202018_final.pdf

The IRP process also failed to identify correct individual LSE targets that would successfully and collectively meet statewide needs. Thus, there are likely serious issues yet to be resolved in the IRP modeling process. In the case of the 2017-18 cycle almost no LSE's IRP was identified as being individually in excess of greenhouse gas ("GHG") allocations,[10] the Hybrid Conforming Portfolio ("HCP") nonetheless exceeded the total GHG target.[11] If that assessment of the HCP's assessment is accurate, that suggests that the Commission's method of assigning GHG allocations is inadequate to ensure the aggregated portfolio would meet the Commission's targets. Thus, the Commission must revise its approach to assigning GHG emissions allocations.

B. The 2017-2018 IRP Cycle Failed to Make Adjustments for Changing Conditions and Market Realities

The IRP process must be robust enough to identify transient market fluctuations and changing conditions, such as the creation of new CCAs and the retirement of newly uneconomic generation facilities. A planning process that cannot correct for market fluctuations and changing conditions will misalign procurement and market realities.

The IRP process must recognize the predictable changes in CCA resource mixes that occurs during the first few years of CCA operation. New CCAs do not typically have the history or financial footing with which to immediately sign large, long-term contracts. Thus, the resource mix of a new CCA often consists of short-term contracts and system power. However, after this initial phase, CCAs typically develop the financial positions and track record to engage

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[10] Either according to the Commission's standards or because the individual data by Energy Service Provider ("ESP") was inadequate to determine their individual GHG allocations.

[11] The Commission should not attribute such a shortfall to failings of LSE strategies, when the major LSEs satisfactorily met the GHG targets set by the Commission. As described more *infra*, the failure of the HCP to hit the GHG target rests with a methodological error in identifying needs and not LSE strategies to meet statutory directives.

in long-term contracting. For example, PCE, which launched in 2016, has contracted for 300 MW of new solar projects; EBCE, which launched in 2018, expects to sign contacts for a significant volume of new long-term California-based renewable projects in the next few months.

The success of the first wave of CCAs has allowed the market to transact more comfortably with new CCAs and shortened the initial phase of new CCAs entering short-term contracts. The snapshot of CCA transactions in the 2017-18 cycle is not indicative of the future; a significant number of CCAs are in the midst of or just emerging from the initial phase. The outlook for these CCAs is likely to be substantially different in the 2019-20 cycle, especially as the Commission develops a better understanding of its informational needs than it had during the 2017-18 cycle.

C. The IRP Process Must Expressly Address Natural Gas Retirement

The IRP process must also plan for the retirements of natural gas generation. Since natural gas generation predominantly contributes GHG emitted by the electric sector in California, *en masse* retirements will likely be necessary to meet the state's GHG goals. Furthermore, IRP modeling results suggest that between 2,100 MW (in CAISO's stochastic reliability assessment of the HCP) [12] and 2,800 MW (in the SERVM LOLE study) [13] of natural gas generation can be retired without harming statewide bringing reliability below industry standards. Certainly, Loss of Load Event frequencies of once every 7,000 or 333 years are well

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[12] *See* CAISO PLEXOS model, scenarios 2 and 3, showing GHG emissions of 25.1 MMT based on more detailed gas dispatch assumptions and California Air Resources Board methodologies for estimating carbon intensities of Northwest imports. (*See* CAISO presentation "Reliability Assessment of the IRP Conforming Portfolio" Presented January 7, 2019, slide 35, http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/4.%20CAISO%202017-18%20IRP%20HCP%20Analysis_01032019.pdf

[13] *See* Energy Division Presentation, at 80 and 101.

in excess of what is reasonably required.[14] Thus, the Commission must help ensure renewable alternatives are in place to meet the associated reliability needs by ensuring that LSEs can direct their procurement intelligently to provide the best alternatives by placing the right resources in the right locations to support the grid. This effort should also take advantage of reports produced in other dockets, especially in the Resource Adequacy proceeding, and produce additional reports to support this effort.

For this transition to happen in an orderly fashion, the IRP process must be refined to identify:

1. critical locations where renewable resources and storage can be deployed to replace fossil fuel fired resources for reliability purposes;
2. key locations and resource sizes where renewable generation and storage can be most effective in addressing reliability needs that would arise from losing natural gas resources;
3. the natural gas resources at greatest risk of retirement;
4. the natural gas resources that contribute the most to GHG emissions; and,
5. the natural gas resources that contribute the most to criteria pollutants.

Any future procurement discussions meant to address identified needs in any proposed procurement track, must also address these issues as well.

D. The 2017-2018 IRP Cycle Could Not Use Updated RPS Standards Given that the Updated Standards Were Revised After the IRP Process Was Already Underway

The Proposed Decision critiques the Hybrid Conforming Portfolio ("HCP") for not "com[ing] close to achieving" the 60% Renewables Portfolio Standard ("RPS") requirement of SB 100,[15] but SB 100 went into effect after the CCAs had submitted their IRPs to the

[14] *See* Energy Division Presentation, at 67.
[15] Proposed Decision, at 106.

Commission.[16] Consequently, the IRPs submitted by the CCAs, and modeled by the Commission, were based on CCA plans to meet the then-existent 50% RPS requirement. Had the 60% RPS requirement been in effect earlier, CCAs would have planned for, and filed, IRPs that met the 60% requirement. The Proposed Decision itself recognizes that the passage of SB 100 occurred too late to be modeled in the current IRP cycle, though it relegates such acknowledgement to a footnote.[17]

The Commission has pledged to "take up [SB 100] policy implementation in the next cycle of IRP."[18] Accordingly, the Commission should use the next IRP cycle to identify the resource mixes necessary for California to meet its 60% RPS requirement, a target neither modeled nor anticipated in the 2017-2018 results.

E. The 2017-2018 IRP Cycle Had Numerous Methodological Issues

There are numerous methodological issues with the 2017-2018 cycle results that could and should be improved in order to develop a more reliable model. These improvements can have major material impacts on the model results, as demonstrated by the significant reductions in GHG emissions resulting from improvements to the assumed carbon intensity of Northwest imports. In addition, the 2019-20 cycle should improve solar and especially storage cost

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[16] Stats. 2018, Ch. 312. SB 100 went into effect after LSEs filed their IRPs with the Commission in August 2018 and just before the September 24, 2018, ALJ ruling seeking comments on an updated production cost modeling approach proposed by Commission staff (the HCP) as well as the "production cost modeling and analysis conducted by Commission staff to study a version of the Reference System Plan (RSP) adopted by D.18-02-018, calibrated to the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) demand forecast and other assumptions for 2017."

[17] Proposed Decision, at 106 note 10. It appears that the Legislature recognized that the adoption of SB100 would overlap with SB 350's IRP planning process. While SB100 raised the RPS requirement to 60% by 2030, the Legislature did not correspondingly change the IRP planning requirements of SB 350. The current applicable statute (Pub. Util. Code § 454.52(a)(1)(B)) only requires that a LSE's IRP ensure that it "[p]rocure at least 50 percent eligible renewable energy resources by December 31, 2030," which is a criteria met by the HCP's achievement of a 52% RPS.

[18] *Ruling of Assigned Commissioner and ALJ Seeking Comment on Policy Issues and Options Related to Reliability*, November 16, 2018, at 4 (emphasis added).

estimate, allow LSEs to substitute load profiles based on local historical data, capture the impacts of demand response and load shifting on local load — an increasingly important issue as LSEs increasingly rely on load shifting strategies to match load to generation; and assign direct value to avoiding criteria pollutant emissions, especially in disadvantaged communities ("DACs"). This last issue in particular could be critical to correctly identifying the value of CCAs renewable procurement to reduce impacts on DACs. Without such a factor, the SERVM model may erroneously suggest it is not "cost effective" to reduce health impacts in DACs.

F. The Modified RSP Is Not Meaningfully Different Or Improved Over The HCP

The Commission should recognize that there is no meaningful difference between the modified RSP and the HCP. First, the difference in reliability metrics of the two portfolios of Loss of Load Events frequency of 0.00014 for the RSP and 0.003 corresponds to a difference a loss of load of once in 7,100 years rather than once every 333 years.[19] Both timeframes are far longer than the timeframe in which California's energy system will exist, and so represent failure rates of zero within any meaningful planning horizons. Second, the SERVM model suggests a difference of 1.5 MMT per year, which represents a 3% difference between the two portfolios.[20] Since the various models have shown sensitivity to assumptions and methods of over 20%, a 3% difference is far smaller than the error variance around the estimates. Where that error variance is larger than the difference, any difference between the portfolio estimates is at least as likely to be a modeling artifact as it is to be a real difference.

Consequently, the Proposed Decision should be modified to recognize that there is no clear meaningful difference between the portfolios and consequently either accept the staff

[19] *See* Energy Division Presentation, at 67.
[20] *See* Energy Division Presentation, at 89.

recommendation to adopt the HCP, at least on an interim basis, or make clear that the modified RSP is adopted only until better modeling clarifies whether there are real differences between the portfolios.

IV. THE MODIFIED VERSION OF THE REFERENCE SYSTEM PLAN THE PROPOSED DECISION PROPOSES TO ADOPT AS THE PREFERRED SYSTEM PORTFOLIO MUST BE FURTHER VETTED

The Commission should defer adoption of the PD's modified version of the Reference System Plan ("RSP") as the Preferred System Portfolio ("PSP") until parties can review and respond to the model. The Proposed Decision would reject both the HCP and the original RSP and would instead adopt "a modified version of the [RSP], utilizing the 2017 IEPR assumptions and a 40-year life for fossil-fueled resources, as a proxy for potential retirements, until better information becomes available in the next cycle of the IRP process."[21] The Commission should not adopt the PD's modified version of the RSP portfolio because the model was never adequately verified or benchmarked.[22] Such benchmarking as was done (e.g., cross-model comparisons) call the accuracy of the models used into question, as discussed above.[23] In addition, the models could also be verified against historical data by modeling projections of GHG and performance based on some prior year and comparing model estimates against actual performances from subsequent years.

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[21] Proposed Decision, at 109.

[22] *See* D. 15-10-028, mimeo at 18-20: "Moreover, we have recognized the value of calibration in modeling in diverse contexts, including gas and telecommunications. Conversely, not calibrating a model when the option to do so exists is bad practice."

[23] *See* Pub. Util. Code § 1822(a), which requires a computer model to "be available to, and subject to verification by, the commission and parties … to the extent necessary for cross-examination or rebuttal, subject to applicable rules of evidence." While the statute refers to any "computer model that is the basis for any testimony or exhibit in a hearing or proceeding before the [C]ommission" and does not expressly refer to a computer model that is the basis for a proposed decision, the Commission should be held to the same standard as parties and be required to provide computer models that satisfy the availability and verification statutory requirements of Section 1822(a). (emphasis added).

The proposed PSP does not appear to rely on properly modeled or vetted results. The Proposed Decision explains that "modeling presented in [Southern California Edison's ("SCE")] January 31, 2019 comments tested a portfolio similar to the RSP with 2017 IEPR assumptions, but including the assumption that fossil-fueled units retire after a 40-year-life."[24] However, the Proposed Decision fails to demonstrate that this portfolio was subject to production cost modeling or other validation. The Proposed Decision simply states that "[a] combination of SCE modeling and Commission staff analysis demonstrate that the RSP with 2017 IEPR assumptions and a 40-year fossil-fueled resource retirement assumption is a viable option for adoption as the PSP."[25] For the Commission staff analysis, the Proposed Decision attempts to compare two SERVM model runs, after which it can only conclude that the proposed PSP is "likely reliable," given it "was not run through a production cost model by Commission staff."[26] Parties and the Commission can only "infer" the model is reliable,[27] as opposed to allowing parties to validate record-based information. Thus, the Commission's SERVM models can only *infer* — as opposed to validate — that the PSP the Proposed Decision would adopt is reliable and can only do so by relying on non-record based information.

A. The Commission Should Not Adopt the PD's Modified RSP Because It Fails to Meet the Requirements Of Its Own Decision In This Proceeding

The Commission should also not adopt the PD's modified version of the RSP portfolio because there is no evidence that the model includes the correct or same inputs the Commission adopted in this proceeding. In D.18-02-018, the Commission recognized that parties "may wish

[24] Proposed Decision, at 106 (emphasis added).
[25] Proposed Decision, at 106.
[26] *Id*. at 107.
[27] *Id*. at 107.

to … conduct their own modeling to evaluate" the PSP and thus required production cost modeling to evaluate the PSP and ensure a specified "calibration and vetting process."[28]

There is no evidence that SCE "calibrated and vetted" its PLEXOS model according to the requirements of D.18-02-018. Included in the "calibrating and vetting" requirements are use of consistent assumptions. SCE itself states that its PLEXOS model used its own internally generated data.[29] Further compounding this lack of transparency is that significant portions of SCE's model was submitted under seal as confidential and not available to any party to the proceeding to review. Thus parties are prevented from determining whether SCE actually or accurately modeled the PD's proposed PSP, or if it instead modeled some variation thereof. Consequently, the Proposed Decision should not rely on SCE's PLEXOS model as support for adoption of the selected PSP.

B. The Commission Should Not Adopt The PD's Modified RSP Because It Inappropriately Relied on RESOLVE Models

The Commission should not adopt the PD's modified RSP because it inappropriately relies on RESOLVE models to develop the final proposed PSP. Given the high-level planning function of the RESOLVE model, and its inability to address hourly procurement and overall reliability, the Commission prohibited its use in developing a PSP and instead ordered Commission staff to "utilize the [SERVM] in preparation for aggregating individual [IRP] plans to form a Preferred System Plan to be considered by the Commission."[30] The PD notes that moving from RESOLVE to SERVM in the original RPS results in a 4 MMT increase in GHG

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[28] D.18-02-018, mimeo at 175 (Ordering Paragraph 18) and Attachment B.
[29] *See* Comments of Southern California Edison Company on ALJ Ruling Seeking Comments on Proposal Preferred System Portfolio and Transmission Planning Recommendations, at 14, 17 (January 31, 2019) (SCE's Production Cost Modeling and Simulation Results for the CPUC's Reference System Plan and Hybrid Conforming Case Power Point).
[30] D.18-02-018, mimeo at 174-175 (Ordering Paragraph 17).

emissions from 34 to 38 MMT above the 34 MMT target, which may explain why the Commission directed in D.18-02-018 that the SERVM model, and not the RESOLVE model, should be used for preparing the final PSP recommendations to the Commission.

V. CONCLUSION

The Commission has successfully proven that the IRP process is feasible through the 2017-2018 IRP cycle. However, the Proposed Decision should be revised to:

1) recognize the important and complementary roles in the iterative IRP process played by the local CCA governing boards and the Commission;

2) find that the IRP process was proven feasible, but defer any procurement mandates until after the next iteration of the IRP process in the 2019-2020 IRP cycle; and,

3) defer adoption of the Reference System Plan as the Proposed System Plan until it is properly vetted.

Respectfully submitted,

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Appendix A

Proposed Revisions to Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Findings of Fact

14. Neither ~~T~~the aggregated LSE IRP resources, referred to herein as the hybrid conforming portfolio (HCP), nor the Reference System Portfolio~~, did not meet~~ met the CARB or Commission GHG emissions target for the electric sector for 2030, and the HCP was also ~~less~~ comparably reliable ~~than~~ as the RSP adopted in D.18-02-018, as updated with the 2017 IEPR assumptions.

~~23. The RSP, with adjustments updated to reflect the 2017 IEPR assumptions and including a new assumption of a 40-year life for natural gas resources, would meet the RPS requirements in 2030 and the Commission's target for the electric sector of 42 MMT of GHG emissions by 2030.~~

25. The IRP process is not just an advisory planning exercise. Procurement is likely to be ~~required~~ necessary to meet needs identified from the IRP process in the near future after the IRP process is further refined.

~~35. The Commission has the authority to order long-term procurement of renewable integration resources by CCAs, provided in Section 454.51(d) of the Public Utilities Code.~~

Conclusions of Law

12. The updated RSP, with adjustments to reflect the 2017 IEPR assumptions, including an assumption of a 40-year life for fossil-fueled resources, and reflecting the most updated information about transmission availability and cost of upgrades gleaned from the most recent TPP, should be vetted by stakeholders as to whether it should be adopted as the preferred system plan for 2019.

~~18. The Commission should consider exercising its authority to require long-term commitments to renewable integration resources by CCAs in a new "procurement track" of this IRP proceeding.~~

~~19. The Commission should focus a procurement track of the IRP proceeding on the following types of resources: diverse renewable resources in the near term at levels sufficient to reach the 2030 optimized portfolio, in coordination with the RPS program; near-term resources with load following and hourly or intra-hour renewable integration capabilities; existing natural gas resources; and long-duration (8 hour) storage resources.~~

Ordering Paragraphs

9. The rulemaking will remain open to consider adopting a Preferred System Portfolio that shall be based on the Reference System Portfolio adopted in Decision 18-02-018, updated with adjustments to reflect the 2017 Integrated Energy Policy Report assumptions, utilizing a 40-year life assumption for fossil-fueled generation, and updated with the most recent transmission cost

and availability information from the California Independent System Operator's 2018-19 Transmission Planning Process.

~~11. The Commission hereby institutes a procurement track, alongside the planning activities in this proceeding, in order to evaluate the need for the following types of resources: diverse renewable resources in the near term at levels sufficient to reach the 2030 optimized portfolio, in coordination with the RPS program; near-term resources with load following and hourly or intra-hour renewable integration capabilities; existing natural gas resources; and long-duration (eight hour) storage resources.~~