**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 (Filed February 11, 2016)

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE TO THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON INPUTS AND ASSUMPTIONS FOR DEVELOPMENT OF THE 2019-2020 REFERENCE SYSTEM PLAN

Alex J. Morris
Vice President, Policy & Operations

Jin Noh
Policy Manager

CALIFORNIA ENERGY STORAGE ALLIANCE
2150 Allston Way, Suite 400
Berkeley, California 94704
Telephone: (510) 665-7811
Email: amorris@storagealliance.org

January 4, 2019

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA")[1] hereby submits these comments on the *Administrative Law Judge's Ruling Seeking Comments on Inputs and Assumptions for Development of the 2019-2020 Reference System Plan* ("Ruling"), issued by Administrative Law Judge Julie A. Fitch on November 29, 2018.

[1] 174 Power Global, 8minutenergy Renewables, Able Grid Energy Solutions, Advanced Microgrid Solutions, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Avangrid Renewables, Axiom Exergy, Boston Energy Trading & Marketing, Brenmiller Energy, Bright Energy Storage Technologies, Brookfield Renewables, Carbon Solutions Group, Centrica Business Solutions, Clean Energy Associates, Consolidated Edison Development, Inc., Customized Energy Solutions, Dimension Renewable Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectrIQ Power, eMotorWerks, Inc., Enel X North America, Energport, ENGIE, E.ON Climate & Renewables North America, esVolta, Fluence, Form Energy, GAF, General Electric Company, Greensmith Energy, Ingersoll Rand, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Iteros, Johnson Controls, KeraCel, Lendlease Energy Development, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, NantEnergy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NRG Energy, Inc., Parker Hannifin Corporation, Pintail Power, Primus Power, Quidnet Energy, Range Energy Storage Systems, Recurrent Energy, Renewable Energy Systems (RES), Sempra Renewables, Sharp Electronics Corporation, SNC Lavalin, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, Tenaska, Inc., True North Venture Partners, Viridity Energy, VRB Energy, WattTime, Wellhead Electric, and Younicos. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. (http://storagealliance.org).

I. INTRODUCTION.

CESA appreciates this opportunity to provide comment on the draft inputs and assumptions to be used to develop the 2019-2020 Reference System Plan ("RSP") and guide load-serving entities ("LSEs") to plan for and develop a resource mix that helps the state achieves its greenhouse gas ("GHG") emissions reduction, renewables, reliability, and disadvantaged community ("DAC") goals. As the Integrated Resource Planning ("IRP") process completes its inaugural 2017-2018 cycle, the Commission staff has proposed several key improvements. Importantly, CESA supports the Commission's inclusion of gas retirements and optimization of behind-the-meter ("BTM") energy storage as candidate resources in this cycle, though more details and/or enhancements on these matters are still needed. Additionally, CESA offers its feedback on how these added functionalities can be improved upon, as well as providing our recommendations on other key improvement areas for the 2019-2020 IRP modeling. Specifically, CESA provides the following comments:

- RESOLVE should optimize for 'starts' rather than only allow for binary options to keep or retire existing baseline gas resources.
- Age-based retirements should set the threshold at 30 years given that this is often the expected number of years before major refurbishment of gas plants.
- Criteria pollutants being attributed to the location of the emitting resource is a reasonable approximation for the criteria pollutant analysis.
- Hybrid gas-plus-storage resources can and should be modeled as candidate resources in RESOLVE with a few key modifications.
- Solar-plus-storage configurations should be modeled with 'lower-cost storage' candidate resources, as proposed by the Commission staff, and using lower-range cost estimates given that the Lazard study does not reflect investment tax credit ("ITC") benefits.
- The Commission takes a reasonable approach in differentiating capacity and duration cost categories, and such differentiation should be applied when reflecting warranty and augmentation costs across different energy storage technologies.

- Energy storage cost forecasts through 2030 should be benchmarked against actual competitive solicitation bid data and consider learning rate approaches.

- BTM energy storage resources should be modeled as both demand response ("DR") resources as well as separate, non-DR candidate resources and have its selection assessed on a net cost basis.

- Compressed air energy storage ("CAES") should be added as a candidate resource in RESOLVE; otherwise, a proxy approach using pumped storage should allow for sufficient flexibility to approximate the value and capabilities of CAES.

- Operational reserve requirements in RESOLVE should be aligned with actual standards and requirements.

- Discount rates for contracted resources should reflect historical project development success data.

- There should be a 100% discount for 'planned' resources that are not yet contracted for, given that many of these resources are still 'speculative' in LSE Plans.

- An additional long-term planning year beyond 2030 should be modeled to ensure the state is on a trajectory to meet Senate Bill ("SB") 100 goals and provide information on whether to take long-term actions.

- Future models should add the ability to model multi-day or seasonal storage to support achievement of SB 100 goals.

- Explanations should be provided on why distribution deferral value or multiple-use applications ("MUAs") were not included in RESOLVE.

- Transportation electrification forecasts should reflect Executive Order goals in the base case.

Having established expertise and familiarity with the RESOLVE model, CESA's recommended improvements should be adopted into the IRP modeling efforts, especially as modeling in this IRP cycle is more likely to lead to near-term procurement authorizations and/or directives. CESA aims to ensure that IRP modeling efforts provide sufficient accuracy and guidance for regulators and LSEs to approach planning or procure resources that represent least-regrets investments, deliver significant ratepayer value, and achieve the state's important clean-energy and DAC goals. Fundamentally, robust and realistic modeling that reflects the range of energy storage solutions and costs should ensure smart choices for LSEs and ratepayers alike.

II. RESPONSE TO QUESTIONS FOR PARTIES ON ATTACHMENT A.

Question 1: Base case selection. Please comment on the recommended base case assumptions outlined in Section 1 above. What assumptions would you modify and why?

CESA recommends a couple modifications from the proposed base case assumptions. In Attachment A, the Commission staff proposes to use the "mid" case forecast from the 2018 Integrated Energy Policy Report ("IEPR") by the California Energy Commission ("CEC") for electric vehicle ("EV") load while testing one sensitivity that incorporates the goals of Executive Order B-48-18 – *i.e.*, 5 million zero-emission vehicles ("ZEVs") by 2030 – in the base case. The Executive Order represents a policy outcome that the state needs to achieve, so CESA finds it appropriate to incorporate this outcome by adopting the Executive Order sensitivity as the base case, or alternatively, by adopting the CEC 2018 Deep Decarbonization – High Electrification scenario as the base case. Otherwise, the proposed base case assumptions using the "mid case" for the forecasts seem reasonable. These forecasts are developed as part of a stakeholder process – *i.e.*, the Demand Analysis Working Group ("DAWG") – and incorporates key recent changes such as the 2019 Title 24 regulations additional achievable photovoltaics ("AAPV"), which CESA strongly supports.

During the December 7, 2018 Modeling Advisory Group ("MAG") webinar and in Attachment A, the Commission staff clarified how it will consider whether to select the low, mid, or high IEPR forecast based on whichever includes the goals of the Executive Order.[2] As CESA

[2] Ruling, Attachment A, p. 9.

understands it, the 2018 IEPR forecasts do not include the Executive Order goals but there may be a possibility that the 2019 IEPR forecasts will incorporate these goals in one of their cases. CESA thus recommends that the Commission adopt the 2019 IEPR forecast case that incorporates the Executive Order when the RESOLVE modeling is updated in 2020, and if none of the forecasts incorporate the goals of the Executive Order, then the sensitivity proposed in Attachment A should be adjusted and adopted to reflect the Executive Order.

In previous comments, CESA also expressed our broad concerns about the possibility that the CEC's IEPR forecasts may be understating transportation electrification end-use load and/or may have actual transportation electrification loads materialize more quickly than expected/forecasted or used to, especially as the Commission focuses on electrifying the heavy-duty ("HD") transportation sector, which has higher power demands. To the degree that the Commission may be underestimating demand and the timing of the new demand from transportation end-use electrification, CESA noted in those comments about how there may be generation shortfalls that pose near- to medium-term reliability risks given the current tight supply conditions.[3] For such reasons, CESA thus emphasizes the need to incorporate the Executive Order assumptions in the base case and to generally lean toward utilizing "high forecasts" for transportation end-use electrification.

Question 2: Baseline resources. What changes would you make to the assumptions in Section 3 of Attachment A with respect to baseline resources? Explain.

How RESOLVE models baseline resources was a major source of concern and feedback in the 2017-2018 IRP process. In this IRP cycle, with adjustments to the capabilities of

[3] *Comments of the California Energy Storage Alliance to the Ruling of Assigned Commissioner and Assigned Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, R.16-02-007, filed on December 20, 2018, pp. 9-10. See link here.

RESOLVE, the Commission staff proposes to allow for the economic retirement of some, but not all, baseline resources. CESA appreciates this important change, which will more clearly and better identify what the state's long-term resource needs are to achieve its various goals. CESA has some concerns with the assumptions for certain baseline resource types, which is elaborated below in our response to Questions 3-5 regarding Attachment A (*i.e.*, planned resources under development and 'generic' planned resources within the planning horizon), but generally supports the proposed approach to model existing resources, 'mandated' planned resources, and planned resources in other balancing areas.

Question 3: **For planned resources with Commission- or CCA-board approved contracts, for which the Commission may need to seek additional information as described in Section 3 of Attachment A, in the base case:**

a. **Is the existence of an approved contract a reasonable determinant for inclusion in the baseline? Why or why not?**

b. **Is it reasonable to assume a 15 percent failure rate for these approved contracts? If not, what are the sources of uncertainty for these types of resources and how should the Commission plan and account for that uncertainty?**

c. **Provide data sources that speak to contract success rates.**

The individual LSE plans submitted on August 1, 2018 included some details on projects under development that the Commission staff proposes to include in the set of baseline resources but with a 15% failure rate for these approved contracts. CESA agrees with the Commission staff that the existence of an approved contract represents a reasonable expectation that the proposed project will materialize and should thus be included in the baseline. In many competitive solicitations, there are evaluation criteria that ensure project viability through various factors, including verifiable site control, some level of interconnection progress, and developer experience (*e.g.*, reasonable demonstrations of capabilities to deliver completed projects as contracted by showing past experience). With development securities and deposits as well as contractual incentives to meet development milestones and complete projects, the Commission staff is reasonable to expect these generation projects will be mostly completed as contracted.[4]

The Commission staff also rightly reflects some uncertainty around the delivery and completion of projects as contracted through a proposed assumed failure rate for contracted projects. However, while it is reasonable to make a 'ballpark' assumption for this failure rate number, CESA does not categorically support the 15% failure rate. Instead, CESA recommends that the Commission staff assess historical failure rate data from utility and other LSE procurements to more accurately determine this number, perhaps on a categorical basis. For example, at the Commissioner briefing on October 24, 2018, the Commission staff in Rulemaking ("R.") 15-03-011 found a less than 7% energy storage project cancellation rate within the Energy Storage Procurement Framework, pursuant to Assembly Bill ("AB") 2514.[5] At the time of the adoption of energy storage procurement targets with Decision ("D.") 13-10-040, energy storage was a nascent and emerging industry, yet, over the course of the next four years, energy storage project development did not experience high project cancellation rates.[6] In other words, while the energy storage industry was nascent at the time of D.13-10-040 and has matured since then to become a more mainstream resource class, energy storage procurements did not experience failure

[4] CESA notes that new wires transmission projects have different barriers and perhaps lengthier and more challenging permitting processes.

[5] *Energy Storage Market Survey and Recommendations Prepared in Compliance with D.18-01-003 Ordering Paragraph 5*, Commissioner briefing on October 24, 2018, presented by Gabe Petlin, Rachel McMahon, and Kari Smith, p. 5.

[6] During the December 7, 2018 MAG webinar, the Commission staff discussed how this discount rate was chosen based on experience in the Renewable Portfolio Standards ("RPS") program. Though this discount rate may be applicable to RPS resources, it may be worthwhile for the Commission staff to take a comprehensive look across other resource types as a 'check' to validate this discount rate. As noted above, energy storage procurements have seen very low failure rates.

rates as high as proposed to be assumed (15%) in Attachment A, and so such an assumption may be inaccurate, in turn distorting the findings of the modeling.

Therefore, the Commission should evaluate historical procurement and development data not only from the investor-owned utilities ("IOUs"), as done for the AB 2514 energy storage procurements, but also from other LSEs and for procurements and programs for other resource types to assess whether the 15% failure rate is a reasonable assumption. At the same time, precision for this failure rate number is not too important, so long as this number is within the 'ballpark' of what we have seen from LSE procurements historically to reduce over-procurement risks and to ensure sufficient resources to meet our capacity and/or other reliability needs.

Question 4: **For planned resources without approved contracts in the base case:**

a. What criteria should the Commission use to evaluate whether it is reasonable to assume that a planned resource will be completed?

b. Is it reasonable to assume a 50 percent failure rate for these types of resources? If not, what are the sources of uncertainty for these types of resources and how should the Commission plan and account for that uncertainty?

c. Provide data sources that speak to contract or project success rates.

In addition to the already contracted and planned resources, CESA observes two additional types of "planned resources" that should be considered and differentiated in the 2019-2020 IRP modeling. First, there are a class of planned resources that have executed contracts but are still awaiting contract approval from the Commission in the case of IOUs and from the local board in the case of community choice aggregators ("CCAs"). The timing of contract approval depends on the approving body and the process involved, which can range from over one year for testimony-involved applications but can also take a shorter amount of time (*e.g.*, less than eight months) for standard-offer programs with *pro forma* contracts, such as with the Demand Response Auction

Mechanism ("DRAM") or the annual Distribution Investment Deferral Framework ("DIDF") Request for Offers ("RFO"). Again, it may be prudent to use a categorical based failure assessment. Based on recent experience from energy storage solicitations, it may be reasonable to assume a very small or no discount rate for these planned resources. For example, only 6 MW of the total 1,620 MW of energy storage projects procured as of October 2018 were denied by the Commission, constituting less than 1% of executed contracts failing to get approval.[7] For IOU applications and standard-offer programs, the Commission has generally approved the procurement objective and guidelines and vetted the evaluation methodology through public stakeholder processes, which leads to a higher likelihood of executed contracts getting approval, assuming that the IOU has adhered to the procurement objectives and guidelines and appropriately applied their evaluation methodologies.

Second, there is the class of planned resources classified as "other" in Attachment A for "somewhat generic" projected resource additions that were included in individual IRP filings. The Commission proposes to apply a 50% discount rate for such planned resources.[8] Absent mitigating factors to indicate a project truly will be built, CESA instead recommends that the Commission apply a very high or 100% discount rate for such planned resources since many of these resources may still be deemed as 'speculative' in individual LSE plans. While some LSEs discussed how they intend to launch a near-term solicitation for certain resources, as was done for energy storage in the IRP plans by Clean Power Alliance and Liberty Utilities, many LSEs highlighted "generic CAISO system" resources many years away – *e.g.*, an energy storage system 'planned for' in 2027.

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[7] *Energy Storage Market Survey and Recommendations Prepared in Compliance with D.18-01-003 Ordering Paragraph 5*, Commissioner briefing on October 24, 2018, presented by Gabe Petlin, Rachel McMahon, and Kari Smith, p. 5.

[8] Ruling, Attachment A, p. 12.

CESA believes that such resources, while potentially viable, should not be included *in the baseline*, given that it is important to highlight what is needed. The IRP models, resource technologies, and grid needs will evolve over time, and thus it will be important for the modeling to identify these changing needs rather than assuming that certain unsubstantiated potential resources will come online according to the timeline proposed in individual LSE plans. By including these speculative resources in the baseline, the Commission may overlook certain important grid needs, inefficiently procure resources to meet grid needs and GHG emissions reduction objectives, or have a false sense of security about the resources available on the grid. Individual LSEs can continue to highlight these generic resources in subsequent plans or change their plans in subsequent years, perhaps with more specificity to the types and locations of resources, by having the IRP modeling more accurately identifying long-term needs that do not include these generic resources in the baseline.

For these generic system resources, the Commission staff explained at the December 7, 2018 MAG webinar that it would collaborate with the California Independent System Operator ("CAISO") and CEC to identify specific buses and locations where energy storage could reduce congestion. This locational guidance can be helpful as LSEs refine their 2018 plans or develop their 2020 plans, but CESA believes that it is more beneficial to have such generic resources and their locations be determined and/or optimized as candidate resources. It is unclear how this optimization of the location of generic energy storage resources can occur if they are modeled as baseline resources.

Question 5: **As described in Section 3.1 of Attachment A, the 2019-2020 IRP version of RESOLVE will be capable of retiring baseline thermal resources economically within the optimization process. Fixed operations and maintenance costs of baseline thermal resources will be added to RESOLVE's optimization logic, such that existing thermal generators may be retired by the model, subject to**

reliability constraints, if it is cost-effective to do so. Provide suggestions for data sources that could be used for the fixed operations and maintenance costs of baseline/existing thermal resources.

CESA supports the added functionality to be able to economically retire baseline gas-fired resources within the RESOLVE optimization. A recent study commissioned by the Union of Concerned Scientists ("UCS") identified informative potential regarding the possibility of retiring aging thermal resources when using many of the same inputs and assumptions as done in RESOLVE for the 2017-2018 IRP process but with added functionality to look at and potentially retire individual gas units. Under the 42 million metric ton ("MMT") scenario, the UCS study found that 23% of combined-cycle gas turbine ("CCGT") units and 24% of peaker units retired by 2030, and under the 30 MMT scenario, found that 30% of CCGT units and 87% of peaker units retired by 2030, largely replaced by battery storage systems.[9] With this added functionality in RESOLVE for the 2019-2020 IRP modeling, CESA hopes the Commission can build upon some of these efforts.

The Commission staff proposes to allow for retirement of baseline gas resources based on their economic retirement when comparing the fixed operations and maintenance ("O&M") costs to the cost of alternatives and based on the age of the baseline gas resource (*e.g.*, 40 years after their online date).[10] CESA has several recommendations to improve on this portion of the IRP modeling.

First, rather than a simple binary 'keep or retire' set of options based on the fixed O&M costs of the baseline gas resource, CESA recommends that RESOLVE be modified to also

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[9] Specht, Mark G. and Laura M. Wisland. *Turning Down the Gas in California: The Role of Natural Gas in the State's Clean Electricity Future*, Technical Appendix, August 2018, pp. 23-24. https://www.ucsusa.org/sites/default/files/attach/2018/08/Turn-Down-Technical-Appendix.pdf

[10] Ruling, Attachment A, pp. 15-16.

optimize for gas starts, which has significant impacts in terms of criteria pollutants and, in turn, has localized impacts on DACs. Thus, rather than economically retire the baseline gas resource entirely, the RESOLVE model should consider how to minimize starts so that the baseline gas resource could potentially provide capacity during emergencies and contingency events as well as provide operational reserves. With the economic selection of some short-duration energy storage to pair with certain baseline gas resources, for example, starts can be minimized with energy storage providing the front-end start-up capabilities while the gas resource is kept offline until it is needed for emergencies, contingencies, and ancillary services. This occurs because many of these local resources are needed not necessarily for energy but for contingency needs. In this way, ratepayers may benefit from savings from procuring cost-effective energy storage solutions while achieving the objectives to minimize impacts to DACs by reducing criteria pollutants. This cost-effective outcome is not possible without optimizing for starts or without allowing for hybridization of energy storage with baseline gas resources as a candidate resource (more on this in our response to Question 6).

Since RESOLVE is only designed to optimize around a GHG emissions constraint, CESA recommends that the optimization around starts to potentially begin in the separate criteria pollutant analysis, where the Commission staff proposes to address both criteria pollutant impacts from steady-state and start operations, likely from gas plants located in DACs. With individual unit emissions through the parallel SERVM modeling, the Commission staff can then create a feedback loop for results from the SERVM modeling to be fed into the RESOLVE modeling as special cases that would identify the resource mix that would not only identify the optimal resource mix that meets the GHG emissions cap by 2030 but also achieve the criteria pollutant reduction and DAC-focused goals of the IRP.

Second, CESA recommends that the Commission set the threshold for age-based retirements at 30 years after their online date. CESA bases these views on anecdotal discussions of how major refurbishment decisions, even for younger plants, can materially inform the retirement of such plants. Some studies have also highlighted the full expected operating life of gas plants at 50-55 years, with a major refurbishment of the plants needed after 20-30 years.[11] In general though, it may be reasonable to test different sensitivities for the age at which automatic retirements would occur in RESOLVE and how major refurbishments occurring every so often might affect the model's findings.

Question 6: **Candidate resources. Section 4 of Attachment A outlines the proposed candidate resources from which the model can choose for the development of new resources beyond the baseline:**

a. **General: Comment on the appropriateness of all of the resource types proposed to be modeled.**

b. **Storage: Does the proposed approach for modeling energy storage in RESOLVE adequately reflect the latest available storage technologies? What energy storage technology types would require significantly different input values? Explain in detail how the inputs would vary.**

c. **Offshore Wind: Public data about offshore wind cost and potential in California may be limited and/or outdated. Comment on what data is currently available regarding offshore wind development in California and its possible limitations. If you are aware of new data expected to become available in the next year or two, for example through the work of the California Intergovernmental Offshore**

[11] *Combined-Cycle Plant Life Assessments*, Sargent & Lundy, May 2015. https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf

Life Cycle Value for Combined Cycle Power Plants, Siemens presentation at PowerGen Asia, October 2-4, 2013, p. 20. https://www.energy.siemens.com/us/pool/hq/energy-topics/publications/Technical%20Papers/Gas%20Turbines/Siemens-Technical-Paper-Life-Cycle-Value-for-combined-cycle-power-plants.pdf

Logan, *et al*. *Electricity Generation Baseline Report*. National Renewable Energy Laboratory (NREL) Technical Report, January 2017, pp. 92-93. https://www.nrel.gov/docs/fy17osti/67645.pdf

Renewable Energy Task Force, provide specific reference to that information.

b. Storage.

CESA generally supports the Commission's use of Lazard's *Cost of Storage* reports (version 3.0 or any update of this particular study). Despite certain limitations, the Lazard study provides a benchmark and a comprehensive source of public data on the current state of energy storage costs. In particular, CESA supports the Commission revising the capital cost assumptions of battery storage technologies to capture the rapidly-declining technology costs and using the peaker replacement use case and commercial use case, respectively, for in-front-of-the-meter ("IFOM") energy storage and BTM energy storage resources.[12] CESA notes that Lazard's *Levelized Cost of Storage v4.0* was recently published in November 2018, so updates to the inputs and assumptions should be made accordingly, as planned by the Commission staff. [13]

Solar-plus-storage. Several key and important changes have been made to the latest Lazard study, including the addition of solar-plus-storage use cases at the utility-scale and for the residential, commercial, and industrial sectors. CESA frequently commented on this throughout the 2017-2018 IRP process and appreciated that the Commission staff is considering introducing a "lower-cost storage" candidate resource to reflect the price sensitivities connected to having a co-located installation, based on the discussions during the December 7, 2018 MAG webinar. With the release of the v4.0 study, the Commission staff can now use the capital cost estimates for utility-scale and commercial and industrial ("C&I") energy storage systems that are paired with solar in considering a lower-cost energy storage candidate resource when paired with solar.[14]

[12] Ruling, Attachment A, p. 31.

[13] *Lazard's Levelized Cost of Storage Analysis Version 4.0*, published on November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

[14] *Ibid*, p. 26.

However, it is important to note that the cost assumptions for solar-plus-storage systems do not account for the ITC benefits for paired energy storage systems, which will also factor into lower capital cost assumptions for near-term projects – *i.e.*, by adding the depreciation benefit and potential for safe harbor, if a third-party-owned system. According to the National Renewable Energy Laboratory ("NREL"), a high benefit-cost ratio of the solar-plus-storage pairings studied resulted from coupled facilities that store and shift the generation of a solar PV plant (*i.e.*, no grid charging) in order to take advantage of all the ITC offerings, which offer more significant cost savings that offset any loss in revenue from solar-only charging.[15]

At the same time, CESA recognizes that the ITC benefit may also complicate some of the RESOLVE modeling by having to require that paired energy storage systems charge 100% from the co-located solar resource to be able to receive the full ITC benefit.[16] Rather than having to create different generation profiles for solar resources when paired and optimized with energy storage and to build in additional functionality to ensure 100% solar charging, CESA believes it is a reasonable approximation to include lower-cost storage as a candidate resource that will provide guidance to the Commission and the LSEs to pursue solar-plus-storage projects, given that energy storage charging will reasonably occur during periods of low wholesale prices (*i.e.*, when mid-day solar production is abundant) and discharge during periods of high wholesale prices (*i.e.*, when solar production drops off at the evening peak). Given that the ITC benefit is not accounted for in the latest Lazard study, CESA recommends that the low-range estimate, if not a lower cost figure, be used for this new lower-cost storage candidate resource.

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[15] *Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants*, NREL, August 2017. https://www.nrel.gov/docs/fy17osti/68737.pdf

[16] CESA understands that there is a 75%-100% charging requirement from the ITC-eligible solar that scales upwards with the ITC benefit, with the ITC benefit dropping to zero for any charging below 75%.

Hybrid gas-plus-storage. CESA observes that hybrid gas-plus-storage resources were not included as a candidate resource in Attachment A. CESA strongly urges the Commission to update its proposed methodology to include hybridization of existing resources as a candidate resource. There are several reasons for doing so.

CESA notes that hybrid gas-plus-storage resources are not a hypothetical future technology. In fact, the technology has already been installed and is currently operating at multiple locations on California's grid. As such, it is essential to include hybrid gas-plus-storage as a candidate resource since they have already proven to be a viable resource option and there are likely to be additional installations considered over the coming years. Without such resources, the modeling's findings will be too disconnected from real-world solutions. While CESA supports all storage types, as previously noted in our comments,[17] CESA believes hybrid resources can offer many benefits useful for evaluating options with an aging gas fleet, including the provision of key reliability services (*e.g.*, local capacity, spinning reserves) while reducing GHG and criteria pollutants and fuel consumption. The benefits of hybrid resources can disproportionately flow to disadvantaged communities too, addressing near-term potential policy synergies. The installed cost of the energy storage in this configuration may differ enough from regulator 'stand-alone' installations that it is important for hybridization to be added to the suite of candidate resources. Current estimates (2019) for hybridizing an existing gas resource suggest an installed cost of $13.4 million for a 50 MW energy storage unit, or approximately $268 per kW.[18] For comparison, E3's recent estimate for a new gas combustion turbine ("CT") was estimated at around $825 per kW.

[17] *Comments of the California Energy Storage Alliance on the Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability*, R.16-02-007, filed on December 20, 2018, Appendix A. See link here.

[18] *Hybrid Storage Technology: Initial assessment of the greenhouse gas reduction and economic savings from Hybrid EGT adoption in California*, Gridwell Consulting, July 2018, p. 19. See link here.

The modeling obviously would benefit from being able to evaluate head-to-head whether an existing gas unit could be replaced with a new CT or hybridized with energy storage. In addition to the capital cost comparison, hybrid gas-plus-storage resources also provide operational cost savings by allowing resources to provide reserves without operating at its Pmin value. Recent analysis by CAISO suggested that there may be potential shortfalls in reserve capabilities if significant gas retirements occur to meet other policy objectives.[19] Considering this, CESA believes it would be unwise to leave any storage options off the table to meet these challenges. Hybrid gas-plus-storage resources are well-suited to meet certain operational needs such as providing spinning reserves.

Independent modeling results show that significant hybrid deployment is selected under an economically optimal scenario. CESA recently undertook an effort to independently model the effects of hybrid gas-plus-storage resource deployment on California's system, using a model that optimizes long-term capacity expansion decisions in a manner very similar to RESOLVE.[20] At a high level, the modeling inputs were nearly identical to the 2017-2018 IRP inputs, except that 1,100 MW of existing gas resources were made eligible for hybridization with battery storage. The results showed that every single one of the candidate resources made eligible for hybridization was ultimately selected under the economically optimal scenario. This suggests that any IRP modeling effort undertaken that does not include hybrid gas-plus-storage is likely achieving sub-optimal results. Therefore, CESA strongly recommends that hybrids be included as an option to

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[19] *Supplemental Sensitivity Analysis: Risk of Early Economic Retirement of Gas Fleet, ISO 2016-2017 Transmission Planning Process*, published on January 4, 2018, p. 4 and Attachment p. 2. http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-Risksofearlyeconomicretirementofgasfleet.pdf

[20] CESA used Blue Marble to conduct an analysis using it GridPath platform. The methodology and results of this analysis are described in greater detail in CESA's December 20, 2018 comments in this proceeding.

ensure that the most optimal planning results can be discovered through the 2019-2020 IRP process.

CESA recognizes that there are technical challenges in any IRP modeling process as well as competing demands for improved inputs and assumptions. However, we believe the request to include hybrid gas-plus-storage resources can be done relatively easily through simple alteration of some key parameters in RESOLVE. CESA understands that the term "hybrid resource" could have many possible interpretations and configurations for modeling purposes. While CESA believes that all types of hybrid resources should ultimately be included in the IRP, the following should be prioritized for near-term inclusion in the inputs and assumptions:

- Hybridization of existing natural gas-fired CTs using battery storage
- Hybridization of existing natural gas-fired CCGTs using battery storage
- Hybridizations of renewables pursuing tax benefits and firming, self-absorption, or other operational strategies, as mentioned earlier.

CESA's recent modeling efforts are also similar to the approach taken in another 'hybrid potential' study. Collectively, these studies illustrate how hybrid-type modeling of 'candidate resources' is immediately doable in RESOLVE (as shown in figure below).[21] For CCGT units, hybridization primarily affects operation by increasing the ramp rate. The hybrid component allows a faster ramp by helping overcome steam generator thermal lag. Thus, to hybridize an existing CCGT unit, CESA recommends increasing the ramp rate in RESOLVE to 40 MW/min (versus 15 MW/min). The sizing of the battery needed to accomplish this is approximately 20% of the CCGT operating range – *i.e.*, battery size should equal (Pmax – Pmin) * 20%.

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[21] See *Hybrid Storage Technology: Initial assessment of the greenhouse gas reduction and economic savings from Hybrid EGT adoption in California*, Gridwell Consulting, July 2018, p. 55. See link here.

The hybrid storage resource was modeled as the California ISO_Aero_CT candidate resource type with the following characteristics as provided for on the CONV_Candidate and CONV_OpChar tabs in the RESOLVE User Interface. The characteristics not shown in the table below were left at their default value. Highlighted values indicate those modified to represent the hybrid storage resource from the default values.

Input	Default Value	Hybrid Value
Dispatchable	1	1
Must Run	0	0
Regulation?	0	1
Spin?	0	1
Load Following Reserves?	1	1
Min Commit	0	0
Freq. Resp. Total?	1	1
Freq. Resp. Partial?	1	1
Freq. Resp. Contrib.	0.08	0.08
Pmax (MW)	100	50
Pmin (MW)	30	0
Pmin (% of Pmax)	30%	0%
Max Ramp Up (%Pmax/Hr)	100%	600%
Hr at Pmax (Btu/MWh)	9.572	10
HR at Pmin (Btu/MWh)	17.63	0
Min. up- and min. down-time		
Startup Cost ($/MWh)	10	0
Slope (MMBtu/MWh)	6.117	10
Intercept (MMBtu/MWh)	345	0

Finally, the installation cost of the hybrid resources is based primarily on the hybrid control system (including upgrades to the existing plant) and battery components. Through consultation with industry experts, CESA believes its appropriate to use similar installation and O&M costs to those used in the Gridwell study excerpted below.[22] CESA believes these represent a relatively conservative (high) estimate of the total cost based on "first generation" implementation and that actual costs may be lower for future iterations.

[22] *Ibid*, p. 19.

Figure 9: Cost of hybridizing an existing gas resource

Year	EGT Kit and Installation	PV of 20 Year O&M	Total EGT Price	Price $kW-yr on 50 MW EGT Kit for 20 years @ 10%
2018	$14,000,000	$1,460,856	$15,460,856	$36.32
2019	$13,408,863	$1,490,073	$14,898,936	$35.00
2020	$12,770,346	$1,519,875	$14,290,221	$33.57
2021	$12,089,260	$1,550,272	$13,639,532	$32.04
2022	$11,342,050	$1,581,278	$12,923,328	$30.36
2023	$10,757,173	$1,612,903	$12,370,076	$29.06
2024	$10,151,293	$1,645,162	$11,796,455	$27.71
2025	$9,694,413	$1,678,065	$11,372,478	$26.72
2026	$9,396,532	$1,711,626	$11,108,158	$26.10
2027	$9,157,649	$1,745,859	$10,903,508	$25.61
2028	$8,977,766	$1,780,776	$10,758,542	$25.27
2029	$8,756,881	$1,816,391	$10,573,272	$24.84
2030	$8,594,996	$1,852,719	$10,447,715	$24.54

- $5 per MW hours variable O&M
- Ability to provide regulation reserves, spinning reserves, load following, and frequency response
- 10 MMBTU heat rate at maximum measured power, and a zero-heat rate at Pmin

Capacity versus duration differentiation. CESA supports the Commission staff's proposed approach to differentiate capacity- and duration-based costs for candidate energy storage resources. In the assumptions for the Lazard studies, four-hour duration systems are assumed for lithium-ion and flow batteries, without much differentiation of costs for longer-duration energy storage capabilities.[23] The Commission staff proposes a reasonable approach to differentiate duration-based costs for lithium-ion and flow batteries – *e.g.*, by assuming lower costs for adding incremental duration for flow batteries, which is a bi-product of adding additional electrolytes. CESA supports this approach and may highlight the solutions to address longer-duration needs, particularly in periods of high renewables integration.

Warranty and augmentation costs. The latest Lazard study noted that it added warranty and augmentation costs to the analysis but assigns this warranty expense equally across all

[23] *Ibid*, p. 28.

technologies and use cases.[24] Rather than applying the same warranty and augmentation costs toward all energy storage technologies and durations, CESA supports the Commission staff's proposed approach to separately attribute these costs to the duration category, especially since these costs may vary for different usage profiles.[25] For flow batteries and potentially other non-lithium-ion technologies, it is also reasonable for the Commission staff to assume lower or no warranty and augmentation costs given the lower or no degradation experienced by these technologies.

Energy storage cost forecasts. The Commission staff proposes to use energy storage cost declines from the latest Lazard study through 2022 and then to assume the pace of cost reductions slowing to zero at a linear rate through 2030, causing energy storage costs to flatten out for both the capacity- and duration-based cost categories by 2030.[26] As expressed in previous informal comments, CESA continues to hold the view that confidential competitive solicitation data on energy storage costs should be used to inform whether the Commission staff should use the high, mid, or low estimate from Lazard's study. At the December 7, 2018 MAG webinar, the Commission staff noted that solicitation data only reflects capacity costs rather than the full cost of energy storage. Even then, recent cost trends may inform what is reasonable to project for costs through 2030. By comparing the year-by-year differences in capacity-only prices bid into competitive solicitations, there can be some understanding of recent price decline trends, though it is unclear which cost driver is declining (*e.g.*, capital versus engineering, procurement, & construction ["EPC"] costs) and/or whether the location of projects may be a confounding factor (*e.g.*, certain locations may have much higher land/site costs or may have higher upgrade costs due

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[24] *Ibid*, p. 28.
[25] Ruling, Attachment A, p. 31.
[26] *Ibid*, p. 32.

to constraints). CESA recognizes these challenges and, to the degree possible, it may be informative to at least review the applicability of this actual cost data.

Since the IRP modeling is being conducted through the 2030 planning year, the fact that the energy storage cost declines flatten out at 2030 and beyond will not affect the current IRP cycle, but CESA is concerned about the implications of this assumption for any modeling done as sensitivity cases for any post-2030 planning years or any modeling done in future IRP cycles. Though the Commission staff explained that this projection aligned with other third-party public sources, such as Bloomberg New Energy Finance ("BNEF"), Navigant, and NREL, it has not been demonstrated that it is a reasonable assumption for energy storage costs to flatten out by 2030. CESA believes that learning rate approaches should be used to forecast out energy storage cost projections, as done in a 2017 academic study that showed that energy storage technologies, particularly lithium-ion batteries, are on track to experience pronounced price drops at a quicker pace that other comparable alternative energy solutions (*i.e.*, solar photovoltaic panels).[27]

BTM energy storage optimization. CESA seeks clarification on how BTM energy storage will be modeled in RESOLVE. CESA appreciates the addition of BTM energy storage as a candidate resource in RESOLVE, but the documentation of the inputs and assumptions in RESOLVE provide little detail on whether BTM energy storage will be optimized independently in RESOLVE or whether BTM energy storage will optimized and selected as one of the technologies in the DR supply curve for Shed and Shift DR, or both. Considering most BTM energy storage provides local capacity as DR resources (*e.g.*, as Local Capacity Requirements ["LCR"] resources or via the DRAM) and BTM energy storage is assumed to not contribute to

[27] Kittner, N, Lill, F, Kammen, D.M. "Energy storage deployment and innovation for the clean energy transition", *Nature Energy*, July 2017. https://rael.berkeley.edu/wp-content/uploads/2017/07/Kittner-Lill-Kammen-EnergyStorageDeploymentandInnovation-NatureEnergy-2017.pdf

operational reserve requirements, it may seem reasonable to assume that BTM energy storage resources will be selected and optimized within RESOLVE as DR resources – *i.e.*, as Shed or Shift DR resources.

However, this approach would not represent a major change in making BTM energy storage a candidate resource since Shed and Shift DR are already candidate resources. A strong case could be made for modeling BTM energy storage independent of candidate DR resources that may highlight the benefits of BTM energy storage resources to provide additional value to the grid with exporting capabilities. The Commission staff acknowledged some of the overlap of BTM energy storage resources selected independently versus those that are selected as DR resources in the December 7, 2018 MAG webinar. Some of this overlap can be addressed by considering how BTM energy storage, when modeled independently (*i.e.*, not as a DR resource), can provide capacity and energy through exports to the grid, subject to transmission constraints like other market-facing resources. Granted, there may be distribution constraints that may limit exports from BTM energy storage resources, but such constraints are not modeled in RESOLVE, to CESA's knowledge, which could be highlighted as a limitation of the BTM energy storage optimization.[28] Thus, CESA recommends that the Commission staff model BTM energy storage as both an independent candidate resources in addition to as one of the available technologies of candidate DR resources.

Finally, for BTM energy storage resources as a candidate resource, the Commission staff should consider modeling them on a net cost basis as opposed to an absolute cost basis. Given the ability of BTM energy storage resources to manage customer bills, BTM energy storage resources

[28] While distribution constraints are not modeled in RESOLVE, CESA believes that these constraints may be able to be modeled in future IRP cycles once distribution deferral values and hosting capacity analysis are incorporated into the model.

may only need a portion of its total installed costs to be accounted for through the provision of system-level grid services. In the future, with distribution deferral value added to the optimization, BTM energy storage resources should incorporate this added value to their net cost assessment.

<u>Question 7</u>: Should large periodic maintenance costs to utility-scale generators be included in IRP modeling? If so, what data sources should be used to estimate these costs? Please refer to Section 3.1.1 of Attachment A for more discussion of this issue.

To the extent that these costs can be material and will affect economic viability and cost-recovery needs of the generator, or that the maintenance costs will affect retirement decisions, the costs should be included. CESA has no comment at this time on the proper data sources for estimating these costs.

<u>Question 8</u>: IRP modeling in 2017 optimized investment and system dispatch for four representative years: 2018, 2022, 2026, and 2030. The number of representative years represents a balance between precision and model runtime. In modeling for the 2019-20 IRP cycle RSP, Commission staff again proposes to limit the simulation to four years, replacing the 2018 Year with 2020, but continuing to include Years 2022, 2026, and 2030. Then, in the next IRP cycle, study years would become 2022, 2026, 2030, and 2034, with the subsequent cycle addressing Years 2024, 2026, 2030, and 2034 (and so on). This allows for continuity and comparison of assumptions and results across IRP cycles, while continuing to focus between 10 and 12 years in the future. Do you support this approach or recommend a different distribution of study years (*i.e.*, updating the study years with each IRP cycle)? Explain your answer.

CESA supports the proposed approach looking at four representative years over a look-ahead period of 10-12 years. However, there should be some flexibility and discretion exercised by the Commission staff to potentially look at specific years as sensitivities if the situation warrants, such as with a key policy change (*e.g.*, expiration of tax credits, retirement of a key resource like Diablo Canyon) that may occur in a non-study year.

In addition, CESA found it helpful to run a limited set of sensitivities that look at an even longer planning horizon, as was done in the 2017-2018 IRP cycle for 2034, to assess whether certain long-term and/or policy actions may be needed in preparation of resource needs at that time. This is perhaps even more important now that SB 100 has directed a transition to 100% GHG free energy by 2045. The binding 2045 date should be factored into the modeling since the past model showed a selection for new gas plants. Presumably, knowing these resources would need to retire or be converted to a 'reliability only' resource[29] is prudent information that will affect modeling findings. Some resources like pumped storage or other 'bulk, infrastructure-like' projects may require some additional lead time to develop, which would benefit from signals and indicators provided by the IRP modeling looking at longer planning horizons. For these reasons, CESA believes a 'far look-ahead' scenario is an essential sensitivity.

<u>Question 9</u>: In order to analyze the Senate Bill (SB) 100 goal of 100 percent of retail electricity sales being supplied by zero-carbon resources by 2045, Commission staff are also considering using RESOLVE to run a limited number of scenarios on years beyond 2030. Considering the significant amount of modeling and run-time cost of each additional planning year, as well as potentially limited availability of data for years beyond 2030, what year(s) should be studied (*e.g.*, 2035, 2040, 2045) and why?

With SB 100 passed, CESA agrees that it will be important to consistently assess whether the state is in a good position to achieve its longer-term 2045 goals as well. As noted in our response to Question 8, there are benefits to modeling an additional long-term planning year to ensure that the state is on the right trajectory and to determine whether certain least-regrets actions could be taken, including for resources that may require additional policy development or that may

[29] The 'reliability-only resource' is not well defined, and CESA uses it only as an example concept here. Conceptually, in a 100% GHG-free scenario, some emitting resources may be retained and hybridized with energy storage. These resources would then be operated such that emissions were zero in non-contingency conditions, in line with statute.

require longer project development lead times. CESA recommends that either or both 2040 and 2045 be included as an additional planning year. Modeling the 2045 year has the benefit of providing an end-state marker for the state to strive for. Meanwhile, modeling the 2040 year would allow the state to progress toward a longer-term goal while providing some buffer between 2040 and 2045 to make adjustments and/or corrective/additional actions to ensure achievement of our 2045 goal.

Question 10: **Voluntary procurement of in-front-of-the-meter renewables beyond statutorily-required levels could impact the development of new renewable energy facilities. For example, many LSEs have programs that allow customers to choose a higher portion of renewables in their electricity supply than required by the RPS, which could result in a need to build additional new renewable energy facilities. Should RESOLVE include projections of voluntary planned procurement (but not yet contracted) when developing future resource portfolios? If so, what are publicly available sources of information that could be used to forecast the volume of such procurement?**

CESA recommends the same treatment of voluntary IFOM renewables beyond RPS requirements as other resources that are planned but not yet contracted.

Question 11: **How should the utilization of the LSEs' current and forecasted REC banks be represented in RESOLVE? Which of the modeling options described in Section 8.3.2 of Attachment A are most appropriate for the base case? What additional options should be considered?**

CESA has no comment at this time.

Question 12: **Provide any additional comments on the appropriateness of the draft inputs and assumptions proposed for the 2019 RESOLVE model runs for IRP purposes. What changes would you make and why? Please include references to the appropriate section number of Attachment A.**

CESA appreciates the opportunities to engage the Commission staff and the E3 modeling team through regular MAG webinars as well as the opportunity to provide informal comments on the draft sources documents, earlier in 2018. While appreciative of these opportunities, CESA has several areas of additional comment where we seek further clarification and consideration in this IRP cycle or in future IRP cycles.

First, CESA observes that no new energy storage technologies are included as candidate resources. CESA responded in previous informal comments with respect to the two new candidate resource criteria to make the case for adding compressed air energy storage ("CAES") and gas-plus-storage resources: (1) resource must have plausible trajectory to commercial availability within planning time horizon; and (2) magnitude of potential impact on future portfolio costs and composition must be sufficient to justify changes to model functionality and run-time.[30] Attachment A does not address these comments, so it would be helpful for the Commission staff to articulate the reasons why different new technologies did not sufficiently meet the new candidate resource criteria. Though the Commission staff previously pointed to pumped storage as a proxy for bulk long-duration resources, CESA sees value in modeling certain new technologies and configurations, such as CAES and liquid air energy storage ("LAES") technologies, which have unique cost structures, are characterized as 'lumpy' investments, and include other unique values that cannot be approximated by proxies such as pumped storage. For example, CAES technologies may be a more affordable technology for certain use cases with different energy storage durations, ramp rates, and other capabilities that would not be sufficiently captured by pumped storage or would not be selected through pumped storage as a proxy in RESOLVE.

CESA understands the challenges and complexities in modeling every possible candidate resource technology and believes a proxy approach can work for certain candidate resource technologies. As a result, CESA supported the new candidate resource criteria and aimed to

[30] *Informal Comments of the California Energy Storage Alliance on the Draft Sources for the 2019-2020 IRP Supply-Side Resources Document*, R.16-02-007, filed on April 23, 2018, p. 14. See link here.

demonstrate how CAES and gas-plus-storage resources met the two criteria. At minimum, if the aforementioned candidate resources are not added to the RESOLVE modeling in the 2019-2020 IRP modeling and the Commission relies on proxy approaches in certain cases, CESA recommends that the Commission clearly explain the model simplifications and contextualize how to interpret modeling outputs when making policy determinations and/or authorizing new procurements. For example, in lieu of modeling CAES separately and individually in RESOLVE, the Commission staff should explain and interpret how the selection of pumped storage resources in any resulting RESOLVE modeling signals long-duration (or other) needs. Furthermore, with this proxy approach, key sensitivities where certain operating parameters (*e.g.*, duration, ramp rate) or costs can be adjusted for pumped storage to mimic CAES should be included in the 2019-2020 IRP modeling. Relatedly, the Commission should clarify how or if resource needs identified or 'selected' in RESOLVE translate to actual procurements. While the model should fully 'know' of the representative range and prices of energy storage solutions that can be deployed, parties should also know how solicitations that result from IRP findings can allow for competition from an array of energy storage solutions.

Second, CESA recommends that the Commission calibrate the operational reserve constraints in RESOLVE to align with actual standards and requirements set by the North American Electric Reliability Corporation ("NERC"), effective January 1, 2018,[31] and adopted by the CAISO. NERC BAL-002-2 requires the CAISO to procure and maintain operating reserves to meet the greater of the load requirement (3% of load forecast and 3% of generation) or the most

[31] *BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event*, NERC. https://www.nerc.com/files/BAL-002-2.pdf

single severe contingency ("MSSC").[32] In the day-ahead market, the CAISO has set the operating reserves requirement to the maximum of 6.3% of the load forecast, the MSSC, or 15% of forecasted solar production, and in the real-time market, this requirement has been set at the NERC load requirement.[33] By contrast, the default assumption is 3% of the hourly CAISO load in RESOLVE,[34] which is not aligned with the CAISO's current operating procedures and would underestimate the operating reserves needed for the grid. These should be aligned to ensure that the resulting portfolios from RESOLVE meet establish minimum reliability standards and are in compliance. CESA believes the lack of sub-hourly granularity and of local or sub-local contingency needs may render the RESOLVE findings as insufficient for actual reliable operations, thereby creating misalignment between IRP-directed outcomes and the actual grid needs.

Third, CESA seeks feedback from the Commission staff on why the 2019-2020 IRP modeling will not incorporate distribution deferral value in the selection of BTM resources and why broader MUAs will not be modeled. These two additional functionalities appeared to be in the process of development and potential inclusion in this upcoming IRP cycle. Stakeholders may benefit from understanding the challenges and may be able to offer support and/or recommendations to address any of these challenges.

Finally, RESOLVE continues to lack the ability to model multi-day or seasonal storage.[35] Though CESA does not propose that the 2019-2020 IRP process consider multi-day or seasonal

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[32] *Implementation of BAL-002-2*, presentation by Dede Subakti. http://www.caiso.com/Documents/Presentation-BAL-002-2DisturbanceControlStandard-ContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf

[33] *Q2 2018 Report on Market Issues and Performance*, CAISO, published on August 20, 2018, p. 19. http://www.caiso.com/Documents/2018SecondQuarterReportonMarketIssuesandPerformance.pdf

[34] Ruling, Attachment A, pp. 44-45.

[35] Ruling, Attachment A, p. 19.

storage at this time, future IRP cycles must build this functionality into RESOLVE or any other future model used. As the state pursues SB 100 goals, there will be an increasing need for long-duration energy storage that can shift load across multiple days and seasons. The Commission staff should focus on how this functionality can be built into future capacity expansion and optimization models.

III. RESPONSE TO QUESTIONS FOR PARTIES ON ATTACHMENT B.

Question 1: Are there any emissions factors that should be used instead of those listed in Tables 1 and 2, or sources already cited in party comments referenced, in Attachment B? Please provide the specific factor, category of unit to which it applies, data source, and reason why it should be used.

CESA supports the actual unit performance where possible, and if not, the use of the emissions factors listed in Tables 1 and 2. CESA does not recommend any other sources that could be used at this time.

Question 2: Comment on the suggested steady-state emissions factors for biomass and diesel units in Table 3 of Attachment B. Propose factors for cold, warm, and hot starts, as well as sources for suggested values.

CESA has no comment at this time.

Question 3: Suggest emissions factors for geothermal facilities and provide sources for suggested values.

CESA has no comment at this time.

Question 4: Should out-of-state emission be accounted for as part of criteria pollutant emissions? Why? If so, how?

CESA does not support 'resource shuffling' to achieve the state's GHG and criteria pollutant emissions reduction and DAC goals. However, if data sources or approaches to measure out-of-state emissions as part of the criteria pollutant analysis is unavailable or insufficiently developed, CESA recommends that this analysis focus on the CAISO balancing authority.

Question 5: Suggest any methodologies to assist with understanding the impacts of system-level emission on the ambient air quality of local communities.

CESA agrees with the Commission and various stakeholders who expressed during the 2017-2018 IRP process around the challenges of attributing impacts of criteria pollutant emissions to specific locations and regions, leading the Commission staff to assume that "emissions would stay where they are produced" as noted in Attachment B.[36] In this next IRP cycle, the Commission staff seeks feedback on how to allocate and understand the impact of system level emissions on local communities, noting that criteria pollutants may end up impacting neighboring communities due to wind patterns.[37]

A study by Krieger, *et al* in 2016 found that location of the gas plant is a reasonable approximation of localized emissions impact[38] and thus it may be reasonable to continue with the 2017-2018 IRP approach where emissions are assumed to "stay where they are produced" and primarily impact those communities. Alternatively, if the Commission staff wishes to pursue more accuracy with localized impacts, the methodology from the Krieger study could be used and adapted, whereby the criteria pollutant emissions generated from specific plants are cross-referenced against separately measured air quality days. For example, in the Krieger study, the Pio Pico Power Plant in Southern California was 14-18% above the particulate matter ("PM") standard and 45-85% above nitrogen oxides ("NOx") standard on "poor" air quality days. By

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[36] Ruling, Attachment B, p. 3.

[37] *Ibid*, p. 5.

[38] Krieger, Elena M., *et al*, "A framework for siting and dispatch of emerging energy resources to realize environmental and health benefits: Case study on peaker power plant displacement." *Energy Policy*, Volume 96, September 2016, pp. 302-313.

cross-referencing the location of plants being dispatched with the location where certain air quality standards are exceeded, the Commission staff may be able to decipher the localized emissions impact of specific plant dispatches to some degree, though not entirely accurately as the operation of neighboring plants could also be contributing to poor air quality. The limitation of this approach is that it is backward looking rather than forward looking, but it may inform how to model localized emissions impact of existing and new resources – *e.g.*, starts and dispatch of Plant A in Location B has historically correlated with some percentage of NOx and PM emissions in Location B and C, so continued or different operations of Plant A would have some percentage impact in Location B and C on a going-forward basis.

Question 6: Provide any other comments or suggestions on issues raised in Attachment B.

CESA supports the Commission's incorporation of not only the steady-state emissions impact from criteria pollutants including NOx and PM2.5 of thermal generators, but also the criteria pollutant emissions from sulfur dioxide ("SO2") and the impact from the hot and cold starts of thermal generators.[39] The proposal to conduct the RESOLVE and SERVM modeling in parallel is also prudent and more efficient to ensure that the RSP aligns with the goal of reducing criteria pollutants. As previously noted, CESA believes that RESOLVE should optimize for starts as well when considering whether gas plants should be retained or retired. Energy storage in the right applications can minimize starts to support criteria pollutant reductions. The inclusion of unit starts in this analysis is important given studies that have shown how units that are spinning and operating at partial load generally emit more pollutants per MWh than units operating at full capacity. For example, the Aspen study found that one start of one specific facility can emit as

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[39] *Ibid*, pp. 2-3.

many NOx emissions as the facility would have emitted in 12-38 hours of steady-state operation.[40] A UCS study found an increase in the number of peaker starts through 2026 and an increase in the number of CCGT starts through 2030 when modeling many of the same scenarios using many of the same inputs and assumptions as done in RESOLVE for the 2017-2018 IRP process. In one scenario, the UCS study found that a large number of CCGT plants modeled would go from zero starts in 2018 to at least 200 times by 2030, which is attributable to the significant number of renewable generation needed on the grid to achieve the state's GHG emissions reduction goals.[41] Thus, it is an important step for the Commission to include starts in resource planning.

IV. CONCLUSION.

CESA appreciates the opportunity to submit these comments to the Ruling. CESA looks forward to working with the Commission and stakeholders in this proceeding.

Respectfully submitted,

Alex J. Morris
Vice President, Policy & Operations
CALIFORNIA ENERGY STORAGE ALLIANCE
2150 Allston Way, Suite 400
Berkeley, California 94704
Telephone: (510) 665-7811
Email: amorris@storagealliance.org

Date: January 4, 2019

[40] *Senate Bill 350 Study: Volume IX Environmental Study*, prepared by Aspen Consulting for the California ISO, July 8, 2016, pp. 97-100. https://www.caiso.com/Documents/SB350Study-Volume9EnvironmentalStudy.pdf

[41] UCS study, p. 29.