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STATE OF CALIFORNIA

BEFORE THE CALIFORNIA ENERGY COMMISSION

In the Matter of:	Docket No. 17-IEPR-07
Developing Regulations, Guidelines, and Policies for Implementing SB 350 and AB 802	Anaheim Public Utilities Department's Response to Questions for Discussions and Comments in Draft Staff Paper: The Proposed Guideline Topics for Publicly Owned Utilities' Integrated Resource Plans
	March 23, 2017

Anaheim Public Utilities Department's Response to Questions in Draft Staff Paper: The Proposed Guideline Topics for Publicly Owned Utilities' Integrated Resource Plans

Thank you for the opportunity to provide responses to questions outlined in the Proposed Guideline Topics for Public Owned Utilities' Integrated Resource Plans (IRP), as discussed at the February 23, 2017 IEPR Commissioner Workshop on Public Owned Utilities Integrated Resource Plans. To help guide the Commission in this process, Anaheim Public Utilities (APU) recommends that the Commission adopt regulations consistent with the following principles:

- **POU governing boards develop and adopt IRPs.**

  Section 9621 (b) of the Public Utilities Code orders that, "The governing board of a local publicly owned electric utility shall adopt an integrated resource plan and a process for updating the plan at least once every five years to ensure the utility achieves all of the following [IRP goals]." The intent of the statute is clear that the POUs' governing boards, not the Commission, have authority over the process of IRP development, adoption, and update as long as it complies with the statutory requirements.

- **The Commission may only recommend corrections with regard to statutory requirements.**

Section 9622 (b) of the Public Utilities Code orders the Commission to "…review the integrated resource plans…" only for consistency with the requirements of Section 9621, and if the Commission determines that the IRP adopted by a POU governing board is "inconsistent with the requirements of Section 9621" then the Commission "…may provide recommendations to correct the deficiencies." The statute does not grant the Commission authority to regulate POU planning assumptions or implementation methods used to meet statutory requirements.

- **The IRP is a resource "plan" and not a compliance document.**

  Section 9621 (b) of the Public Utilities Code requires the POUs adopt an integrated plan to achieve SB 350 goals, but compliance with statutory requirements is governed pursuant to the applicable regulations, outside of the IRP process. For example, compliance with the renewable portfolio target is governed by the Commission under the Renewables Portfolio Standard (RPS); compliance with the emission reduction target is governed by the California Air Resources Board (ARB).

  In addition, IRPs are based on long-term production cost modeling for resource planning and, as in any long-term forecast, estimated variables and assumptions may deviate from actuals during the IRP planning horizon. While the IRP outlines the POU's best estimates and plans to achieve its planning and policy goals, changes in any variable will impact its planned outcome. APU takes exception to any implied message that the IRP may be viewed as a separate and additional compliance measure.

- **The Commission's IRP Guidelines should focus solely on the submission of information, data and reports to facilitate the Commission's review of the IRP, per statutory requirements.**

  Section 9622 (c) of the Public Utilities Code states, "The Commission may adopt guidelines to govern the *submission of information and data and reports needed to support the Energy Commission's review* of the utility's integrated resource plan." As such, the Commission should only request data and information that is necessary to complete its review of whether or not the POU meets the statutory requirements as outlined in Section 9621 (b).

Responses to the specific questions are below.

1. **Is it appropriate to require that supporting analysis for IRPs be undertaken in the 24 months prior to adopting an IRP? Is there an alternative time frame that is more appropriate?**

It is appropriate for IRP supporting analysis to be performed within the 24 months prior to adopting an IRP. For clarification, the IRP Guidelines should not require the *submission* of data ahead of the adoption of a POU's IRP.

2. Are there select areas of analysis that should be exempt from meeting this 24-month requirement because of the analysis is not time-dependent?

There may be situations in which data or other information, upon POU review, still remains valid, and should be considered exempt from this requirement regardless of whether it is time-dependent or not.

3. What constitutes an IRP update?

The POU and its governing board determine what constitutes an IRP update. A POU may determine that its IRP requires an update due to changes in resource portfolio, market conditions, legislative/regulatory requirements or other factors. Upon the determination that an IRP update is warranted, an IRP update will be developed and adopted by the POU's governing board per the requirements of Section 9621.

4. SB 350 requires updates "at least once every five years."

a. Is it appropriate to require IRPs be adopted and submitted to the Energy Commission every four years to consolidate and leverage other similar requirements?

Section 9621 (b) of SB 350 requires that "On or before January 1, 2019, <u>the governing board</u> of a local publicly owned electric utility shall *adopt an integrated resource plan and a process for updating the plan* at least once every five years." According to the statute, APU believes that each POU's governing board should be allowed to determine its frequency for updating and adopting the IRP, as long as it meets the first submittal deadline and subsequent submittals are within the five-year reporting timeline. It may be convenient for the Commission and some POU's to submit their IRP every four years consistent with the IEPR submittals, but is likely to not be convenient to others that may have existing processes or budgetary constraints. The Commission should defer to the statutory timeline.

Such flexibility is essential for each POU's IRP preparation and adoption. An IRP requires extensive staff hours for planning efforts and public outreach, and possible engagement of costly consulting services. The IRP is also subject to budgetary constraints, other local policy considerations and a public process for governing board approval, which may differ for each POU.

b. Are there existing reporting requirements that could potentially be combined with the IRP?

As suggested in the Draft Staff Paper, the Capacity Resources Accounting Table and Energy Balance Accounting Table could potentially be combined with the biennial IEPR submittal. However, APU contends that each POU should determine its own timeline to submit the IRP and accompanying data as long as it meets statutory requirements. Any regulation should be flexible and contain optionality.

5. Stakeholders have requested an optional "informal review" process of an IRP by the Energy Commission prior to an official submittal.

a. What are the benefits or concerns of including an optional informal process in the guidelines?

APU believes the optional informal process may be beneficial for POUs; however, the informal review should be limited to whether or not the IRP meets the statutory requirements of SB 350.

b. What questions, issues, or practices should this informal process address?

The Commission staff may work with the POUs seeking the optional informal review to determine the questions, issues, practices and scope of the review. The informal review process should review the adequacy of the draft document in meeting the requirements of SB 350.

c. What is the scope of the review?

See the previous response.

6. Staff requests public input on the following options to address this as well as other potentially duplicative reporting requirements. Below are some options that staff is considering:

a. Two submission dates:

i. Adopted IRPs would be due to the Energy Commission by January 31.

ii. Data forms would be due April 30.

b. Delay IRP due date until April 30.

c. Require that the POUs submit their IRPs by January 31 and Electricity Resource Plans by May.

APU appreciates the Commission staff's effort to combine reporting requirements. However, as previously stated, POUs should be allowed to determine the frequency for updating and adopting the IRP, as long as they meet the first submittal deadline and subsequent submittals are within the five-year reporting timeline. This implies that a POU should be able to submit its first IRP to the Commission anytime between the current date and January 2019. It should also be allowed to submit its IRP update at any time interval within the next five years of the first submittal.

If the POU's IRP analysis can be submitted concurrently with the IEPR Resource Plans, it should be allowed to do so. However, POUs should not be required to submit the IRP and its analysis based on the IEPR timeline.

7. **What additional guidance or data will POUs need to consistently model and present GHG emissions associated with energy purchased from selected portfolios?**

APU strongly recommends that the Commission coordinate with the ARB to establish GHG emissions factors for both out-of-state and in-state generation resources. The ARB's established emissions factor for unspecified imported power could be used as a proxy for any market purchases until such time as the emissions associated with in-state power are determined by ARB.

Pricing assumptions for GHG emissions would also be appropriate for the Commission to establish consistency with assumptions being used by the ARB or with other carbon pricing regulations (e.g. any carbon taxes or other pricing mechanisms that may be adopted by the State or Federal government). However, the use of these assumptions should be optional. If the POU chooses to utilize a different forecast for GHG emissions costs, they should be permitted to do so.

8. **How should flexibility needs be presented and discussed in the IRP?**

APU is within the CAISO balancing area and adheres to the FERC-approved CAISO tariff regarding flexibility requirements, as documented in Section 40 "Resource Adequacy Demonstration for All Scheduling Coordinators in the CAISO BAA". CAISO calculates the flexible capacity requirements for APU and other POUs within the CAISO boundary. APU encourages the proposed IRP guideline for POUs to be consistent with or make reference to the CAISO tariff, and allow POUs to adopt assumptions and analysis based on CAISO Flexible Capacity Requirements.

9. **Overgeneration may present a problem for utility portfolios whose loads are met with a large share of solar energy. How should potential over-generation be quantified and addressed in the IRP?**

Overgeneration has been a concern and an area of heightened interest for the CAISO, which has developed and broadened its Energy Imbalance Market in response to the over-generation of renewable energy in California. As an LSE within the CAISO balancing area, APU relies on CAISO to balance the system load and responds to CAISO market signals to dispatch our flexible natural gas power plants as called upon, which at this time is typically in the early morning and in the evening ramp hours.

In addition to relying on a balancing authority such as CAISO to balance the load, POUs may report its estimated renewable generation on the Energy Balance Accounting Table, as suggested under Topic 2 Data Reporting of the Draft Staff Paper. POUs may also assess the impact of over-generation in other aspects of portfolio evaluation, such as estimated wholesale energy prices, cost of renewable integration (including ancillary services and Flexible Capacity Requirements).

APU has taken into consideration the potential reliability issues and elevated renewable integration costs stemming from overgeneration of non-dispatchable renewable facilities. As such, a notable portion of APU's renewable portfolio are composed of base-load renewables such as geothermal and landfill gas. In addition, APU's solar and wind facilities are geographically diverse, with generation profiles complimentary to each other avoiding overgeneration during certain parts of the day.

10. Is the ARB's emissions intensity of 0.428 mt CO2e/MWh appropriate for spot market purchases and/or energy from unspecified sources under long-term contract? If not, how should a new value be determined?

The ARB's unspecified emission intensity of 0.428 mt CO2e/MWh was developed prior to 2010 and only represents the expected emissions of out-of-state generation that is imported into California under either a short-term market purchase or pursuant to a contract that does not specify a generation resource. The emission intensity factor should be updated by the ARB to reflect changes in the overall western area and grid as both renewable generation increases and the generation from coal facilities overall decreases.

APU believes that as the entity authorized to regulate and measure California's carbon emissions- the ARB - is the agency responsible for calculating emission intensity factors in various regions. Emission intensity factors referred to in the Commission's IRP guideline must be consistent with the ARB's calculations. POUs should also be allowed to develop their own emission intensity factor for unspecified purchases when they have more insight on their unspecified purchases.

11. Should staff develop emissions intensities for generic natural gas-fired resources or should this be left to the POUs? For other generic generation resources?

APU believes that the ARB is the agency responsible for calculating emission intensity factors for generic natural gas-fired resources or other generic generation resources. Emission intensity factors referred to in the Commission's IRP guideline must be consistent with the ARB's calculations. The use of a generic generation resource emissions intensity should, however, be optional for the POU. POUs should also be allowed to develop their own emission intensity factor for generic resources when they have more insight on their planned resources.

12. **Staff would like input from the parties on exactly what data and/or information is most meaningful in understanding the impact of overgeneration.**

    Please see response to Question 9.

13. **How should potential risks to reliability and resource adequacy caused by climate change be considered in the IRPs?**

    Climate change and its potential impacts to reliability and resource adequacy may be considered in the IRP qualitatively or in the narratives. The qualitative analysis may include possible effects on customer load, energy demand and capacity requirements due to weather extremes. The narratives may include the POU's evaluation of the significance of related impacts, and its plans in response to such impacts.

14. **(13.) Should POUs be required to use forecasts consistent with the Energy Commission's annual demand forecast or use their own forecast?**

    The use of the Commission's annual demand forecast should be optional. APU develops a demand forecast as part of the annual power supply budgeting process. The underlying demand forecast is approved when the power supply budget is formally adopted by the City Council. POUs should be permitted the flexibility to use either the Commission's demand forecast or the demand forecast as adopted by their Governing Boards.

15. **(14.) The Energy Commission's demand forecast incorporated effects of climate change for both energy consumption and peak demand. Should any forecast used in IRPs do the same?**

    Demand forecasts used in the IRP should incorporate the POUs' own analysis on potential effects of climate change for both energy consumption and peak demand. POUs should have the optionality to adopt the Commission's demand forecast in its IRP.

16. **(14.) What input assumptions are appropriate for standardization? Examples might be resource costs and performance characteristics, fuel prices, and demand growth rates.**

While it is appropriate for the Commission to develop recommendations for some of the modeling inputs, the use of these inputs should be optional. The Draft Staff Paper suggests that the Commission should develop standardized assumptions in areas such as GHG emission costs, EV impacts, EV adoption rate, regional load forecast, transmission constraints, CAISO's TAC charges, resource costs, performance characteristics, fuel prices, and demand growth rates. APU strongly believes that POUs should be permitted to develop their own assumptions with the flexibility to use the Commission's standardized assumptions for the following reasons:

(1) POU assumptions are approved by the governing boards

APU has been consistently developing and determining production cost modeling assumptions as part of the annual power supply budgeting process. The underlying assumptions are approved when the power supply budget is formally adopted by the City Council.

(2) POUs are diverse

POUs are vastly diverse in load profile, geographic region, customer demographics and resource portfolios. Standardization of POU input assumptions is difficult and may not be possible. For example, the penetration of electric vehicles may be higher in urban areas than in rural areas. Additionally, demand growth rates will be highly dependent on whether there is significant development or redevelopment occurring in the service territory or if there is little change. In both cases, statewide assumptions may not accurately capture the reality faced by the individual POUs.

POUs should be allowed the option to adopt the input assumptions most appropriate for their service area and operating constraints, as long as the approach and methodology are articulated in the narratives. APU welcomes the Commission's assumptions as a point of reference and comparison.

(3) POUs use different modeling tools

POUs may have in-house production cost modeling tools, or contract with consultants to perform production cost modeling. Each modeling tool has its own optimization algorithm and a complete set of input assumptions with regards to transmission constraint, resource costs, performance characteristics, fuel prices and regional demand growth rates. These algorithm and assumptions are calibrated to regional actuals on a regular basis. Merely changing parts of the input assumptions as mentioned above may cause the model to be out of sync with historical actuals, therefore adversely impacting long-term portfolio evaluation results.

(4) Publication timing of the standardized assumptions may not be in line with POU's budget or IRP development timeline

A POU may develop its budget and IRP much earlier or months after the Commission publishes the most recent set of assumptions. Due to the timing difference, the POU may not be able to utilize the Commission's standardized assumptions.

17. (15.) Should staff require a standardized assumption for GHG allowance/carbon costs, and if so, what assumption should be used? Which metric should be used, carbon cost or GHG allowance?

As stated above, APU strongly believes that POUs should be permitted to develop its own assumptions for GHG allowance or carbon costs. However, APU welcomes the Commission's assumptions as a point of reference and comparison. Carbon cost is preferable to GHG allowance because it can be more easily compared to other energy, integration or environmental costs.

18. (16.) Are there possible unintended consequences of various methods for setting the value or cost of GHG emissions?

Like any other assumption used in production cost modeling and energy portfolio evaluation, there are various methods for estimating the value or cost of GHG emissions. It is in the best interest of all utilities to develop the best cost estimates for long-term decision making and the effect of costs on customers. APU does not believe it would be a major concern that POUs utilize various methods to estimate the cost of GHG emissions.

19. (17.) Should a high GHG allowance/carbon cost sensitivity be required? If so, how should cost be established?

Each POU has a different energy and risk profile. Based on the POUs' internal risk assessment, POUs should determine if a high GHG allowance/carbon cost sensitivity is desired in their IRP development. If the POU chooses to model a scenario with high GHG allowance/carbon cost sensitivity, the cost should be consistent with the ARB's calculations where available.

We would like to thank the Commission for its on-going efforts to seek POU input regarding the development of integrated resource plans as required by the passage of SB 350. APU welcomes continued collaboration with the Commission as this process moves forward.

Respectfully Submitted,

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