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)

REPLY COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE INTEGRATED RESOURCE PLANS

INDEPENDENT ENERGY PRODUCERS ASSOCIATION
Steven Kelly, Policy Director
PO Box 1287
Sloughhouse, CA 95683
Telephone: (916) 448-9499
Facsimile: (916) 448-0182
Email: steven@iepa.com

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In response to the Administrative Law Judge's email ruling on September 17, 2018 clarifying that any party, including but not limited to load-serving entities (LSEs), may file and serve reply comments to other parties' previous comments on individual Integrated Resource Plans (IRPs), the Independent Energy Producers Association (IEP) provides these Reply Comments.

IRPs were submitted to the Commission on August 1, 2018. The IRP submissions preceded enactment of Senate Bill (SB) 100. The IRP submissions also preceded the Governor's Executive Order (EO) B-55-18 to Achieve Carbon Neutrality. SB 100, among other things, increased and accelerated Renewables Portfolio Standard (RPS) obligations. For example, the required percentage of retail electricity sales served by energy from RPS-eligible resources increases to 44 percent by December 31, 2024; 52 percent by December 31, 2027, and 60% by December 31, 2030. Similarly, EO B-55-18 charts a new statewide goal to achieve carbon neutrality as soon as possible and no later than 2045.[1]

[1] Executive Order B-55-18 To Achieve Carbon Neutrality (September 10, 2018).

In reviewing the IRP submissions by LSEs, the Commission should consider SB 100 and EO B-55-18 in the 2017-2018 IRP cycle, and not defer consideration of these critical policies to the next IRP cycle (2019-2020), as this may delay critical decisions necessary to ensure compliance with the state's policies. In addition, the Commission should focus on the feasibility of the IRP submissions, both individually and in aggregate; the consistency of the IRPs with the 2018 RPS Procurement Plans recently submitted by jurisdictional LSEs; and the treatment of non-compliant IRPs. IEP elaborates on these matters in greater detail below.

I. Feasibility of Individual IRPs

The Commission should review and assess the feasibility of the IRP submissions individually and in aggregate. As a practical matter, while the IRPs of individual LSEs (or sub-groups of LSEs) may be consistent with the planning and modeling assumptions employed by the Commission, when considered in the aggregate these plans may be infeasible given infrastructure constraints, the dynamics of energy markets, and the needs of the electric grid. In this context, IEP focuses on two areas of known concern: namely, the role of large hydro, particularly out-of-state hydro, in achieving IRP goals, and the availability of transmission to access renewable resources in the desert of Southern California.

A. Role of Large Hydro (Out-of-State)

The California Community Choice Association (CalCCA) tracks the use of a combination of out-of-state large hydro, existing large hydro within the control area of the California Independent System Operator (CAISO), and Asset-Controlling Supplier (ACS) contracts. CalCCA reports that 38,370 MWs of such resources reside within the Northwest and

Southwest regions.[2] The Commission must ascertain whether the assumptions made by LSEs regarding the availability of large hydro capacity for their individual needs is feasible given the constraints on the hydro system, particularly constraints on the large hydro system located in the Pacific Northwest (PNW).

CalCCA, for example, comments that the majority of contracted supply in 2018 to serve Community Choice Aggregation (CCA) load is from large hydro, including contracted supply from ACS contracts. Out of a total 8,100 MWs of contracted positions in 2018, approximately 4,000 MWs derive from contracts with large hydro/ACS-sourced resources, i.e., nearly 50% of the total contracted capacity derives from large hydro.[3] Moreover, CalCCA comments that the bulk of *future* contracts from existing resources are expected to be sourced from large hydro/ACS resources, ranging from approximately 75% of the supply in 2022, 70% in 2026, and 70% in 2030. This represents approximately 4,200-5,000 MW of capacity sourced to large hydro/ACS resources.[4] CalCCA indicates collectively these plans are feasible, because the RESOLVE model documents 7,844 MWs of large hydro capacity with CAISO and another 4,766 MW within other regions of California (e.g., Imperial Irrigation District and the Los Angeles Department of Water and Power).

With regards to the feasibility of accessing large hydro outside of California for purposes of meeting IRP goals in the near term as well as the long term, particularly large hydro located in the PNW, it is important to appreciate the following:

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[2] Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities, p. 12.
[3] Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities, p. 7.
[4] Ibid, p. 10.

- Large hydro represents approximately 33,000 MWs (nameplate) of installed capacity in the PNW. Yet, due to the inherent intermittency of hydro (and wind) in the PNW, the ability of generation in the area to consistently produce electricity at or near nameplate is undermined.[5]
- One of the challenges for the PNW to maintain an adequate, economic, and reliable power supply in the future is the necessity of allocating a larger share of generating capacity, due to the high rate of wind development in the PNW, to provide within-hour balancing reserves *in the PNW*, thereby reducing what can be deployed to meet firm load outside of the region.[6]
- The relative ability of the PNW system to provide adequate supply during peak times in the future likely will be reduced due to (a) the growing loads during the summer peak (in a region that has traditionally been winter-peaking), (b) increasing constraints on the hydro system for environmental reasons, and (c) planned closure of coal plants in the PNW.[7]
- Operating constraints and public policy requirements have reduced the overall capacity availability of the PNW hydro system. For example, the PNW hydro systems' firm generating capability over the course of an average year has declined by approximately 1,100 MW since 1990. In terms of firm peaking

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[5] *Realizing the Value of Bonneville Power Administration's Flexible Hydroelectric Assets*, Patricia Florescu/Jack Pead, Harvard Kennedy School, Working Paper Series No. 91. May 2018, p 12.
[6] Ibid, p. 14.
[7] Ibid, p. 14.

capacity, the PNW hydro system capacity has decreased by about 5,000 MWs since 1995.[8]

The energy flows between the PNW and California primarily occur over two major transmission paths totally approximately 8,020 MWs of transfer capacity. One path is the California-Oregon Intertie (COI) with a rated capacity of 4800 MWs; the second is the Pacific DC Interties (PDCI) with a rated capacity of 3,220 MWs.[9] Yet, each path has unique constraints that will impede usage by new market participants in the future:

- ***Regarding the PDCI (3,220 MWs):*** Currently, the PDCI is scheduled on one-hour intervals. It is jointly owned by Bonneville Power Administration (BPA) and the Los Angeles Department of Water and Power (LADWP). LADWP, a municipal utility, is not subject to the Commission's IRP review authority; yet LADWP is subject to many of the state's energy policies such that one might expect that LADWP will utilize the transfer capacity of the PDCI for its own purposes.
- ***Regarding the COI (4,800 MWs)****:* Due to the inability to schedule energy flows in increments smaller than one hour on the DC intertie, real-time sales to California can only be made by using the COI.[10] The COI is capable of scheduling in 15-minute increments. One-third of the capacity of the COI is allocated to public power entities located in California, primarily in northern/central California. While not subject to the Commission's IRP review authority, these public power entities like LADWP are subject to many of the

[8] Ibid, p. 31.
[9] Ibid, p. 24.
[10] Ibid, p. 61.

state's energy policies such that one might expect that these public power entities will utilize the transfer capacity of the COI for their own purposes.

- While BPA owns transmission rights totaling 2,725 MW (56.8%) of the COI capacity north the California-Oregon Border, evidence suggests that BPA's access to transfer capacity on the COI ranges is limited to 600-900 MWs of firm transmission given congestion.[11]
- South of the California-Oregon Border, at least one-third of PDCI transfer capacity (1600 MWs) is allocated to public power entities via ownership rights to the California-Oregon Transmission Project (COTP).
- BPA uses its available transmission capacity to serve its preference customers and regional users pursuant to federal mandate. To the extent that BPA engages in surplus sales to non-preference, non-regional customers, BPA tends to prefer longer-duration energy sales, e.g., commonly 16-hour block energy sales, rather than short-duration sales useful to supporting the integration of intermittent renewables.[12]

Accordingly, while theoretically 4,800 MWs and 3,100 MWs of transmission capacity to the PNW exists via the COI and the PDCI, respectively, the actual availability of the transmission capacity and its utility in accessing PNW large hydro is more complicated. The constraints on the operations of the PNW hydro system may limit the utility of this resource in meeting long-term renewable procurement obligations (e.g., minimum 10-year contracting requirements as prescribed in Public Utilities (PU) Code Section 399.13(b)) or short-term needs

[11] Ibid, p. 24.
[12] Ibid, p. 24.

for flexible capacity to integrate the wind and solar resources planned to be procured to meet GHG reduction goals.

B. Limits on Southern California Desert Transmission Capacity

Southern California Edison (SCE) comments that many individual IRPs assume fully deliverable renewable generation from the southern desert in California. Yet, SCE also comments that the RESOLVE data indicate that the transmission capacity needed to ensure full deliverability is lacking. In addition, SCE notes that the southern desert area has "zero" new wind potential due to land-use screens.[13]

In the context of developing a Preferred Resource Plan in the IRP planning process, parties have noted that the Commission must ensure that the Preferred Reference Plan represents a feasible pathway to meeting the state's greenhouse gas (GHG) reduction goals.[14] As noted by Pacific Gas & Electric Company (PG&E), LSE Plans must be aggregated into a feasible and internally consistent Preferred Reference Plan shared with the CAISO to determine the impact on grid reliability and transmission planning.[15] IEP concurs. The Commission must evaluate the feasibility of LSE IRPs individually and collectively to access new, additional renewables in the southern desert region of California. In the absence of realistic and specific plans to expand the transmission grid to ensure full deliverability of resources from the southern desert of California, IRPs that rely on resources from this area may be infeasible.

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[13] Comments of Southern California Edison Company on Load-Serving Entities' Integrated Resource Plans, p. 23-24.
[14] Opening Comments of Pacific Gas and Electric Company Regarding Load Serving Entities' Integrated Resource Plans Filed August 1, 2018, p. 15.
[15] Opening Comments of Pacific Gas and Electric Company Regarding Load Serving Entities' Integrated Resource Plans Filed August 1, 2018, p. 4.

II. Consistency with RPS Procurement Plans

Parties have noted the importance of ensuring grid reliability while striving to achieve state policy mandates embedded in SB 350, particularly GHG reduction goals.[16] Modelling suggests that an additional 10,000 MWs of renewable generation is needed by 2022 keep on pace to meet RPS and GHG-reduction goals.[17] In addition, SB 100 accelerated and increased the RPS obligations imposed on LSEs, and these changes impact the long-term contracting obligation prescribed in PU Code Section 399.13(b).

Accordingly, with regards to renewable procurement in general and procurement for "new builds" specifically, the Commission should require consistency between the 2018 RPS Procurement Plans submitted by LSE and the 2018 IRPs submitted by those same LSEs. Yet, the extent to which the 2018 RPS Procurement Plans and the 2018 IRPs are aligned is unclear.

CalCCA, for example, reports that the majority of new build projects to meet the SB 350 goals are expected to come from solar generating resources totaling approximately 6,000 MWs in 2030, and 2,600 MWs of wind in 2030, out of a total capacity of 9,900 MWs.[18] Yet, upon review of the 2018 RPS Procurement Plans submitted by individual CCAs, IEP finds that only approximately 1,319 MWs of new project development is planned as of August 2018.[19]

In the absence of any significant renewable development planned by investor-owned utilities, a gap in RPS Planning and IRP Planning looms even though the RPS is critical to achieving the state's GHG reduction goals promulgated in the IRP.

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[16] Opening Comments of Pacific Gas and Electric Company Regarding Load Serving Entities' Integrated Resource Plans Filed August 1, 2018, p. 15.
[17] Presentation, *Proposed Reference System Plan (Executive Summary)*, CPUC Energy Division, September 18, 2017, p. 9.
[18] Comments of California Community Choice Association on Integrated Resource Plans of Load Serving Entities, p. 14.
[19] See Comments of the Independent Energy Producers Association on 2018 Renewable Portfolio Standard (RPS) Procurement Plans, September 21, 2018.

III. Non-Compliant IRPs

Parties recommend that the Commission reject any IRP submission that does not assume compliance with the revised RPS targets embedded in SB 100.[20] IEP concurs. In addition, the Commission should reject any IRP submission that does not address compliance with the related RPS obligations including but not limited to long-term RPS contracting obligation beginning in January 1, 2021 (PU Code Section 399.13(b)) and the product content requirements (PU Code Section 399.16(c)).

Some have suggested that the Commission should develop enforcement provisions to ensure that CCAs and Electric Service Providers actively engage in procurement activities that will reduce aggregate GHGs.[21] While not opposing enforcement provisions, IEP notes that enforcement provisions may not be timely drivers of needed investment in the resources necessary to achieve the state's policy objectives. To ensure timely investment in needed infrastructure, the Commission should exercise its authorities to direct investment in needed resources in a least-cost and best-fit manner and allocate the costs *and* benefits of such investment to all beneficiaries.

IV. Summary

Ultimately, the feasibility of the IRPs individually and in aggregate is critical to meeting state GHG emission-reduction goals while ensuring overall grid reliability. Infeasible IRPs will skew investment and procurement decisions; significantly delay needed investment in resources critical to meeting the state's GHG reduction goals; and, effectively, undermine the very purpose of *integrated* planning. Accordingly, the Commission must determine whether the IRPs

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[20] Comments of The Utility Reform Network on Load-Serving Entities' Integrated Resource Plans, p. 2.
[21] Comments of The Utility Reform Network on Load-Serving Entities' Integrated Resource Plans, p.4.

submitted for its review individually are IRP compliant and, additionally, whether the IRPs in aggregate provide reasonable certainty that the state's policy objectives (e.g., SB 350 goals, RPS goals, reliability) will be met in a timely manner. After all, that is the purpose of integrated resource planning. If the Commission determines that IRPs individually or collectively are deficient in meeting the state's planning and policy objectives, the Commission should be prepared to act on its authority to direct the needed procurement and investment to effectuate state policy objectives in a timely manner.

Respectfully submitted September 26, 2018 at San Francisco, California.

Steven K Kelly

INDEPENDENT ENERGY PRODUCERS ASSOCIATION
Steven Kelly, Policy Director
PO Box 1287
Sloughhouse, CA 95683
Telephone: (916) 448-9499
Facsimile: (916) 448-0182
Email: steven@iepa.com

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