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)

JOINT COMMENTS OF THE BAY AREA MUNICIPAL TRANSMISSION GROUP AND THE CITY AND COUNTY OF SAN FRANCISCO IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON THE PROPOSED REFERENCE SYSTEM PLAN AND RELATED COMMISSION POLICY ACTIONS

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The Bay Area Municipal Transmission Group ("BAMx")[1] and the City and County of San Francisco ("San Francisco" or "City") respectfully submit these comments in response to the Administrative Law Judge's September 19, 2017, Ruling ("Ruling") seeking comment on the Proposed Reference System Plan ("PRSP") (Attachment A to the Ruling)[2] and related California Public Utilities Commission ("Commission" or "CPUC") policy actions. BAMx and San Francisco support California's aggressive Greenhouse Gas ("GHG") reduction goals but are concerned about approaches recommended in the PRSP that could unnecessarily increase the cost of achieving California's GHG objectives.

The Ruling discusses three scenarios, a Default Scenario that reflects existing policies including a 50% RPS, which is equivalent to statewide GHG emissions of approximately 51 MMT; a 42 MMT scenario, the proposed PRSP, that is at the low end of the electric sector emissions range estimated by the California Air Resources Board ("CARB"), and a 30 MMT scenario reflecting CARB's estimated electric sector emissions with no Cap and Trade.[3] The

[1] The members of BAMx are City of Palo Alto Utilities and City of Santa Clara, *dba* Silicon Valley Power.

[2] The Attachment A was subsequently presented and discussed during the CPUC Energy Division workshop on September 25-26, 2017.

[3] Ruling at 8-9.

Ruling does not set forth the incremental costs (above existing costs) of the Default Scenario. The 42 MMT scenario is estimated to cost $239M per year ***above*** the Default Scenario.[4] The 30 MMT scenario is estimated to cost $1,137M per year ***above*** the Default Scenario.[5]

With respect to these scenarios and the policy recommendations in the Ruling, BAMx and San Francisco have the following concerns:

- The assumed level of energy efficiency in the scenarios is too low. As a result, the value of early procurement of renewable resources is likely overstated and the potential curtailment impacts of any such early procurement is likely understated.
- The model's selection of early procurement of renewables to take advantage of expiring tax credits ignores a number of factors that suggest the need for caution in this regard, especially given the relationship to the California Energy Commission's ("CEC") Integrated Energy Policy Report ("IEPR") and California Independent System Operator's ("CAISO") Transmission Planning Process ("TPP"):
    - While the RESOLVE model suggests that early procurement of renewables is ultimately cost effective, in early years this approach results in substantially higher costs, and any benefits materialize only much later and are hence much less certain.
    - The recommendation relies on a host of assumptions that have not been fully vetted.
    - The recommendation relies on an assumption that renewables will offset fossil fueled plant operational costs but ignores the suggestion further in the Ruling that it may be necessary to subsidize some fossil fueled plants in order to ensure that they are available to complement renewables and maintain reliability in the long-term.
- It would be premature to approve transmission projects as policy-driven projects based on the adopted Reference System Plan ("RPS") particularly with respect to early procurement of renewables because of the considerations set forth above, and because Load Serving Entities ("LSEs") must first prepare their own Integrated Resource Plans ("IRPs") considering the RSP, and when LSE IRPs are prepared and harmonized some of the key assumptions of the RSP may change.
- Effective planning is an iterative process that requires timely and flexible exchange of data between the CEC's IEPR, the Commission's IRP process and the CAISO's TPP.

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[4] Ruling, p. 14.
[5] Id.

- The recommendation in the PRSP to use a GHG Planning Price that is a straight line from the current GHG allowance price to the 2030 GHG Planning Price will unnecessarily increase costs.
- The scenarios indicate that out-of-state ("OOS") wind that requires new transmission is not a least-cost-best-fit resource and thus does not justify designating new policy-driven transmission.

I. JOINT BAMx-SAN FRANCISCO RESPONSES TO THE ALJ QUESTIONS

Q. 2. Comment on the appropriateness of the three major scenarios modeled by staff (Default Scenario, 42 MMT Scenario, 30 MMT Scenario).

Q.3. Provide any comments or reactions to the cost metrics analyzed and the estimated cost results.

BAMx and San Francisco do not oppose the modeling of more aggressive 42 MMT and 30 MMT scenarios, particularly as sensitivity scenarios; however, BAMx and San Francisco are concerned that the scenarios underestimate energy efficiency, which in turn understates risks associated with early procurement of renewable resources. Additional energy efficiency reduces the need for new resources and increases the possibility of congestion and curtailments if new resource procurement is nonetheless accelerated.

It is noteworthy that the majority of scenarios are aggressive in terms of GHG reductions. California Air Resources Board ("CARB") 2017 Proposed Scoping Plan estimated the change in GHG emissions by 2030 attributed to the Electric Power sector to be in the range of 42 MMT to 62 MMT.[6] The CPUC Energy Division ("ED") staff-designed Default Case reflects a 50% RPS by 2030 with a statewide target of ~51MMT rather than a statewide GHG target of 62 MMT.[7] The 42 MMT and the 30 MMT scenarios impose even more stringent GHG constraints on the resource portfolio.

We do not agree that the "default" level of assumed energy efficiency (= mid AAEE plus preliminary estimates of AB 802-associated additional savings) corresponds to the State policy goal of doubling EE savings by 2030. We believe that a more representative scenario

[6] CARB 2017 Proposed Scoping Plan, www.arb.ca.gov/cc/scopingplan/scopingplan.htm

[7] Slide #18 of the CPUC ED Presentation, titled, "Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC," July 19, 2017.

implementing the State policy is the ***SB350 – Mid AAEE x2 + AB802*** scenario that combines the State policy goals of doubling EE savings by 2030 with additional load reduction measures associated with savings enabled by AB802. In addition to assuming reasonable levels of EE, preferred resources such as Shift Demand Response ("DR") need to be part of the adopted RSP so that they can be studied as an economic alternative to new generation or transmission.

Q. 4. Comment on the viability of renewable curtailment as a grid integration strategy.

The ED Staff concludes that curtailment of a portion of renewable generation output is a cost-effective solution for grid integration. In the Default Scenario, the model predicts that curtailment would be approximately 3.2% by 2030, while it is 5.7% in the 42 MMT Scenario.[8] The ED staff has found storage to be more expensive than curtailment costs. It would make sense to have renewable curtailment as a grid integration strategy to the extent it is lower cost than many of the more expensive renewable integration options.

Q. 5. Comment on the advisability of early procurement of renewables to take advantage of federal ITC and PTC availability.

If they are allowed to expire, existing federal tax credits for utility-scale renewable energy projects decline sharply or are eliminated by 2030. In particular, the Investment Tax Credit ("ITC") for solar which is currently at 30% is expected to be continued through 2019, but will be stepping down to 10% in 2021 and thereafter. Also, the Production Tax Credit ("PTC") for wind was at 2.3¢/kWh through 2016 and is expected to be stepped down to 0 in 2020 and thereafter. According to the Staff report,

> "…rather than waiting until the plant (Diablo Canyon) is retired (assuming that occurs), the model (RESOLVE) essentially chooses to pre-purchase solar and wind power rather than waiting until the next decade to take advantage of the cost savings associated with expiring PTC/ITC. In other words, the replacement power in the amount of Diablo output is already being replaced by GHG-free resources prior to the retirement of the nuclear

[8] Ruling, p.5.

plant. And in all scenarios, the GHG emissions constraints in the CAISO area are met or exceeded."[9]

BAMx and San Francisco believe that is very important to identify and fully vet the assumptions that are driving RESOLVE to recommend procuring renewable resources early given its relationship with the CAISO's TPP, and the potential impact of increasing the transmission congestion and adding to ever-growing CAISO transmission access charge ("TAC") costs. Such early procurement is not required to meet the State GHG reduction or Renewable Portfolio Standard ("RPS") goals. Changes to key variables, such as extension or replacement of the PTC/ITC, energy efficiency levels, assumed discount rate, future capital costs of renewables, the need to subsidize the capital costs of some fossil-fueled plants to maintain reliability, etc., could have a dramatic impact on whether or not early procurement of renewables is cost-effective.

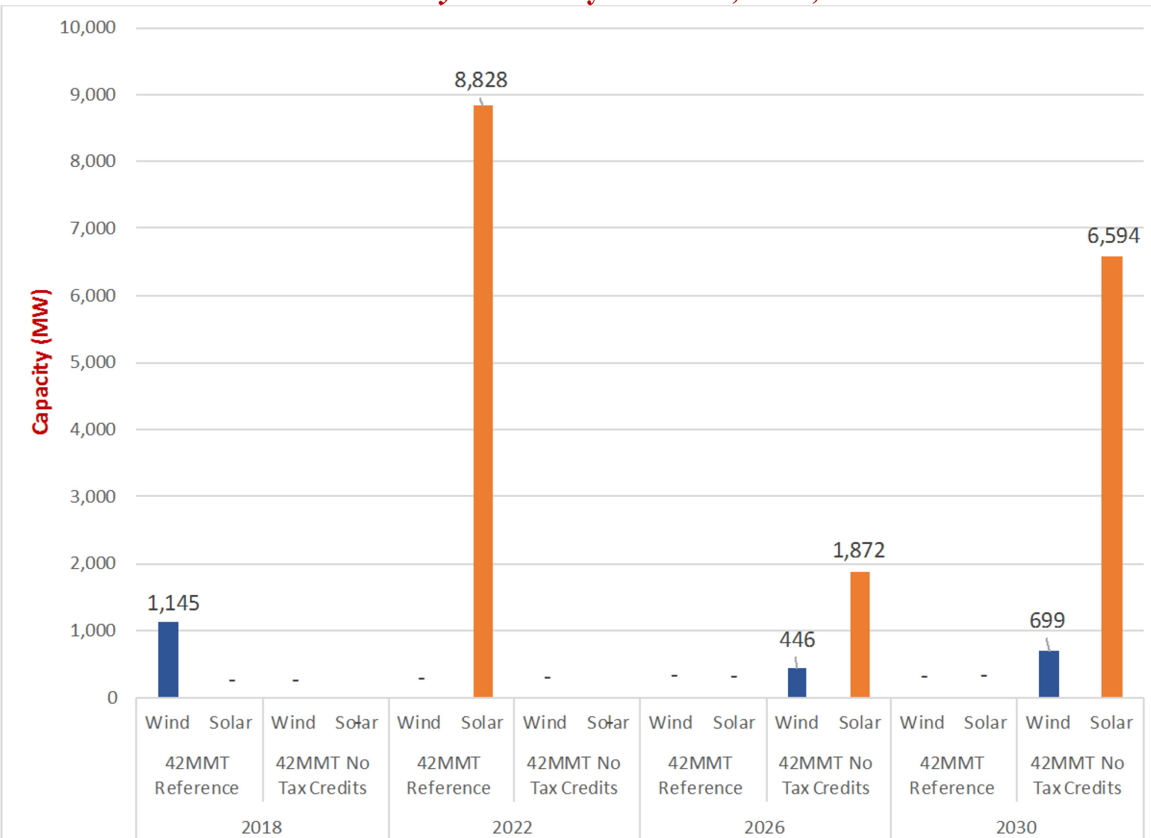
The ***Reference Case*** assumes the existing and projected federal tax credit structure described above whereas, under the ***No Tax Credits Sensitivity*** case, all new renewables are assumed to be developed with no or lower long-term federal tax credits, i.e., there is no PTC for wind and only 10% ITC for solar PV for the entire study period beginning 2018. We used the RESOLVE *Results viewer* to compare the resource procurement (See Figure 1 below) and total costs (See Figure 2 below) in the ***42MMT Reference Case*** with those in the ***42MMT No Tax Credits Sensitivity Case.*** Our comparison indicates that the TRC[10] of the *42MMT No Tax Credits Sensitivity* is $410M more than the TRC of the *42MMT Reference* Case in 2030, but this benefit only materializes in the last years of the analysis.

As shown in Figure 1, in the PRSP RESOLVE selects the renewable resources almost a decade early, i.e., in 2018 instead of in 2026 and 2030 for wind and in 2022 instead of 2026 and 2030 for solar to take advantage of the expiring tax credits. The data included in Figure 1 demonstrates that you would need to procure the solar resources in 2026 and 2030 to meet the State's GHG and RPS goals, however RESOLVE recommends procuring those resources in 2022 to take advantage of the expiring ITCs (as shown in the *42MMT Reference* Case).

[9] Ruling, p.13.

[10] In RESOLVE, the "incremental total resource cost" (or incremental TRC) for each scenario is calculated relative to the Default Case and it represents an annualized incremental cost ($MM/yr) expressed in 2016 dollars over the course of the analysis (2018-2030).

Figure 1: Selected Resources (MW) under 42MMT Reference Case and *42MMT No Tax Credits Sensitivity* Case for years 2018, 2022, 2026 and 2030.



However, the implication of procuring the wind and solar resources early in the *42MMT Reference* Case is ***much greater*** New Renewables Fixed Costs in the years 2018, 2022 and 2026. Similarly, the early procurement of renewable resources necessitates additional costs associated with new storage and balancing resources in these years. These increases in costs are compensated by the lower operating costs in later years in the *42MMT Reference* Case relative to the *42MMT No Tax Credits Sensitivity* Case.[11] Overall, as shown in Figure 2, the incremental total resource costs ("TRC") in the *42MMT No Tax Credits Sensitivity* Case is substantially negative in 2018 and 2022[12], it is as low as $10M in 2026, and only increases to $410M in 2030.[13] In other words, the TRC in the early years are significantly lower in the No Tax Credits

[11] We understand that these lower operating costs might be attributed to the value of the energy displaced by the near-term procurement of solar and wind leading to savings from avoided natural gas fuel and CO2 allowances when additional solar and wind are added.

[12]

[13] In addition to the underlying assumptions on the resource technology cost and the value of tax credits, RESOLVE's selection of new resources earlier in the study period is dictated by the discount rate (assumed at 5%) used to calculate the total resource cost in each scenario over the study period. Reductions in the discount rate would

Sensitivity Case relative to the Reference Case that include early procurement. Since the future is uncertain, trading near term costs for benefits far into the future should be considered with great caution.

Figure 2: Incremental TRC and its Components under the *42MMT No Tax Credits Sensitivity* Case for years 2018, 2022, 2026 and 2030.

As mentioned earlier in response to Q.2 and Q.3, the RSP should assume the EE levels, which are deterministic in RESOLVE, in compliance with the State law. For instance, assuming the SB 350-friendly ***2xEE*** (2 times gain in EE by 2030) levels, significantly lowers the wind and solar procurement in the *42MMT Reference* Case.[14] In other words, more aggressive EE assumptions in compliance with the State law results is a significantly lower amount of renewable resources selected early.

In addition, the ED Staff analysis suggests that early procurement of renewable resources may lead to lower operating cost as the renewable energy displaces other resources such as, gas-

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reduce the savings associated with the tax incentives and reduce the effect of future operating costs of gas-fired resources, due to the time value of money.

[14] RESOLVE Model and Results Package posted at http://cpuc.ca.gov/irp/proposedrsp/

fired generation. This ignores that early procurement also may lead to two types of additional cost. First, in the ED Staff analysis, curtailment is modeled by assuming that the developer is paid its production (contract) cost regardless of whether its output is curtailed or delivered to the grid.[15] However, as curtailments grow, the contract prices of renewables are expected to go up accordingly. Second, the Ruling suggests that it may be necessary to maintain gas capacity to balance renewables in the long term as it could be more economical than alternative solutions, such as storage. California may need to incur additional capacity costs to keep gas capacity operational that otherwise would have been retired due to inadequate operating contract or market revenues. It is not clear whether the ED Staff analysis has incorporated the impact of early procurement not only on the operating costs, but also on the fixed capacity costs.

Given that there is considerable uncertainty associated with at least some of the above-mentioned drivers, and given the impact of these variables on the portfolio outcomes, the Commission should take advantage of the time available by deferring decisions such as the early procurement of renewables while better information is developed.

Q. 10. Do you support the use of the Reference System Portfolio associated with the 42 MMT Scenario as the model for LSE portfolio planning for their individual IRPs? Why or why not?

BAMx and San Francisco do not oppose the *42 MMT* Scenario as a model for LSE portfolio planning for individual IRPs as a more stringent sensitivity scenario to meet the GHG reduction levels that are beyond the States' GHG reduction and RPS goals. However, we have concerns about the RESOLVE model's recommendation for early procurement of renewables. Stringent reliance on the *42 MMT* Scenario without consideration of the risks of significant early procurement of renewable resources could lead to significant over-procurement at significant cost, as described in our response to Q. 5, because the *42MMT* Scenario leads to a much greater level of early renewable resource procurement than in the 51MMT (50% RPS) Default Case.[16]

Q. 11. Do you support transmitting the Default Scenario and associated portfolio to

[15] *Ibid*.

[16] The RESOLVE model selects ~3 GW of new utility-scale solar by 2030; 300 MW in-state wind; and 800 MW of battery storage in the Default Case, whereas it selects 9,000 MW solar PV; 1,000 MW wind; 200 MW geothermal and 2,000 MW battery storage in the 42 MMT Scenario.

the CAISO for use as the reliability base case in the TPP for 2018? Why or why not?

BAMx and San Francisco support the CPUC ED's proposal to transmit the Default Scenario and associated portfolio for use as the reliability base case in the TPP. However, we are concerned about the risks associated with approving reliability projects based upon an aggressive near-term renewable procurement scenario.

Q. 12. Do you support transmitting the 42 MMT Scenario and associated portfolio to the CAISO for use as the policy-driven case in the TPP for 2018? Why or why not?

BAMx and San Francisco do not support transmitting the *42 MMT* Scenario and associated portfolio to the CAISO for use as the policy-driven case in the TPP for 2018. Our response to Q.5 above sets forth our concerns about the recommendation in the 42 MMT Scenario for substantial near-term procurement of renewables.

In addition, it would not be prudent to consider any transmission projects under the policy-driven approval category based on the RSP, which is subject to change based upon updated information in the near future. The next steps in the currently envisioned IRP process entail LSEs filing IRPs that reflect the RSP, followed by the CPUC deciding whether to authorize procurement based on approved, aggregated LSE plans or the Preferred System Plan ("PSP"). There is a strong possibility that the recommended portfolio based upon the RSP would be quite different from the one that is based upon the PSP. Therefore, BAMx and San Francisco suggest using RSP for the 2018-19 TPP for an information only study and not using it for policy-driven transmission assessment. We suggest that the CPUC consider using the PSP for the subsequent planning cycles beginning in the 2019-2020 TPP.

Furthermore, we encourage the CPUC to strive for a shorter lead time for feedback between the CEC IEPR, CAISO TPP and CPUC IRP. Historically, once the CPUC provided the RPS portfolios to the CAISO and the CAISO modeled them in its annual TPP process, it has taken almost a year for the CPUC to incorporate the revised transmission cost and transmission availability data into the CPUC models, such as the RPS Calculator.

It would not be an economically efficient outcome if the CAISO approves a "policy-driven" transmission project in a specific transmission planning process cycle based upon the CPUC-provided resource portfolios that could have been further refined with revised transmission-related information from the CAISO in the same TPP cycle. Therefore, BAMx and San Francisco strongly encourage the CPUC to seek feedback from the CAISO before the resource portfolios associated with the RSPs/PSPs are officially adopted.

One way to achieve this goal would be for the CAISO to run power flow screening studies to identify any issues with the location and capacity of the resources selected in the CPUC's preliminary RSP/PSP portfolio, including whether there are any significant curtailments of generating resources and/or additional transmission upgrades needed. In many cases, a small adjustment to the Full Capacity Deliverability Status and Energy-Only resource amounts could avoid the need for a transmission upgrade. Such information can then be fed back into the CPUC's capacity expansion tools to generate revised Plans that potentially lower the overall system cost. We recommend deployment of a process that would allow for a quick turnaround for each data exchange iteration between the CPUC IRP and the CAISO TPP. We also suggest that the upcoming Commission decision adopting the RSP should explicitly include a provision for the feedback loop between the CPUC RSP and the CAISO TPP.

Q. 14. Do you support the staff recommendation for how LSEs should utilize the GHG Planning Price in preparing their individual LSE IRPs? Why or why not?

The modeling indicates a relatively low GHG Planning Price value from 2018 to 2026, followed by a steep increase during the final few years of the planning horizon.[17] However, Commission staff proposes to project a straight-line increase beginning at the 2018 Cap-and-Trade Allowance Price Containment Reserve value of $66 per metric ton[18] and increasing to a level of the 2030 GHG Planning Price of $150 per metric ton.[19] BAMx and San Francisco are concerned that use of a straight-line increase for the GHG Planning Price unnecessarily raises the costs of achieving California's GHG goals and undermines CARB's Cap-and-Trade Program mechanism. Again, customers could as a result experience near-term high costs that are unnecessary to achieve California's GHG goals, just because current assumptions suggest that prices will increase steeply in later years. However, a variety of factors could moderate the price

[17] Ruling p. 25.
[18] Ruling, Attachment A, p.11.
[19] Ruling p. 25.

increases in the out years. Furthermore, staff's recommended approach could introduce another cost shift by forcing electric sector customers to subsidize other GHG-emitting sectors.

Q. 23. Should the Commission initiate activities with the CAISO or others to investigate further development of out-of-state wind?

a. Why or why not?

b. If so, what specific steps should be taken?

c. Should out-of-state wind be included in a special study or as part as a policy driven scenario for TPP? Why or why not?

BAMx and San Francisco believe it would be premature for an Interregional Transmission Project ("ITP") or OOS transmission project to be considered for approval as a policy-driven transmission as part of the 2018-19 TPP, as OOS is not a least-cost best-fit solution in meeting the State's GHG reduction and RPS goals based upon the currently available information. The RESOLVE indicates that costs associated with the OOS wind scenario are significantly higher than the Default and PRSP plans.[20] And this is occurring even though the RESOLVE model is not allowed to select energy efficiency measures or demand response as part of the optimum portfolio of resources. Even with this limitation, any resource portfolio that forces OOS wind that requires new major transmission results in overall cost increases except under the most stringent GHG targets. Based upon the above, any study of the OOS transmission in the 2018-19 TPP should purely be an ***information only*** special study.

[20] Ruling, Attachment A, p.101 and p.203. The net incremental cost of OOS wind is $211 million/yr and $104 million/yr, respectively in the Default and 42MMT cases, respectively.

III. CONCLUSION

BAMx and San Francisco appreciate the opportunity to provide responses to the questions about the major recommendations contained in the Ruling, and look forward to actively participating in the IRP proceeding.

October 26, 2017 Respectfully submitted,

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