California ISO

Stakeholder Comments Template

Submitted by	Company	Date Submitted
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Please use this template to provide written comments on the Clean Energy and Pollution Reduction Act Senate Bill 350 Study initiative posted on February 4, 2016.

Please submit comments to regionalintegration@caiso.com by close of business February 19, 2016

Materials related to this study are available on the ISO website at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

Please use the following template to comment on the key topics addressed in the initiative proposal.

1. Do you think the proposed study framework meets the intent of the studies required by SB350? If no, what additional study areas do you believe need to be included and why?

Comment: No.

There are a number of key problems with the study framework that must be remedied. First, the study should consider only the impact of including CAISO and PacifiCorp in a single regional Balancing Authority (BA) rather than modeling a scenario where the entire Western grid is operated as a single BA. Modeling the entire Western grid is not reasonable, does not constitute a plausible set of assumptions and fails to provide useful information regarding the costs and benefits of a merger of the CAISO and PacifiCorp BAs.

Second, the development of a “base case” scenario (or “business as usual”) must fully reflect ongoing and anticipated efforts by California to address renewable integration and overgeneration issues. These efforts include incremental commitments to energy storage, Demand Response, electric vehicle charging, retail rate design and improvements to the CAISO's energy market. Further, the study must not assume that "regional integration" is the only answer to managing the damage of procurement activity that becomes irrational over time. California (and other states) should be assumed to take serious steps to address these issues in "business as usual" cases.

Third, the study should assume that PacifiCorp successfully develops the four new Gateway transmission projects identified in its 2015 Integrated Resource Plan regardless of whether CAISO regional expansion occurs. The base case should assume no costs for this new transmission are allocated to CAISO customers through the Transmission Access Charge (TAC).

Fourth, the study should correctly recognize the potential for substantial quantities of out-of-state renewable energy to contribute to California's Renewables Portfolio Standard (RPS) program requirements under a base case scenario that assumes the current rules apply and the footprint of a California Balancing Authority remains unchanged. Under the base case, out-of-state resources can satisfy Product Content Category (PCC) 1, 2 and 3 RPS compliance for California load-serving entities. Any such analysis must also review the projected RPS compliance positions of major investor-owned utilities to properly assess the extent to which forecasted renewable net short positions through 2030 can be satisfied with PCC 2 and PCC 3 resources.

Fifth, the study should model the impact of adding several thousand MWs of Wyoming wind on hourly market energy prices in hubs where the energy is presumed to be sold. These market prices should be netted against assumed Power Purchase Agreement (PPA) prices for purposes of determining the net premiums for any California purchaser. The study should include sensitivities to show the consequences for net premiums under different market energy price scenarios.

Sixth, the study must consider the potential for an expanded balancing authority to permit California Load-Serving Entities (LSEs) to meet RPS procurement requirements from existing renewable resources either connected to, or that can deliver to, the new balancing authority.

Seventh, the study must investigate a number of key impacts of regional integration including the extent to which it helps to manage the "duck curve" associated with California net loads, what regional resources are assumed to reduce dispatch based on the export of California renewable energy resources, and the benefits of any solar diversity across California and the other five PacifiCorp states.

Eighth, the study should rely upon pricing for new renewable energy resources that incorporate real-world observations of actual transactions and rely on the actual availability of federal tax incentives.

Ninth, any analysis of Greenhouse Gas (GHG) emissions should isolate the impact of a regional balancing authority and separately identify changes in GHGs associated with the Energy Imbalance Market.

Tenth, the study assumptions must reflect local operational constraints and local resource adequacy requirements when considering the impacts of regional expansion on unit commitment and dispatch and assessing the reserve sharing requirements.

Eleventh, the study should address other implications of a regional balancing authority, particularly the role of the Federal Energy Regulatory Commission (FERC) and the federal courts will have in affecting states' environmental policies, particularly in manners contrary to states' own considered policy decisions. Such policies could include those related to Resource Adequacy, including centralized capacity markets and the commitment and dispatch of resources in a manner designed to minimize GHG emissions.

Twelfth, the study should consider how a larger balancing authority could affect states' efforts to comply with the Clean Power Plan (CPP) and whether the expected GHG reductions would go beyond CPP requirements. The study should also assess whether the modeled commitment and dispatch of resources designed explicitly to minimize GHGs comports with FERC policies focused on market design and just and reasonable energy prices.

The failure to address these issues in the SB 350 studies would render the results incomplete and misleading for purposes of representing a range of potential impacts from regional expansion.

2. Five separate 50% renewable portfolios are being proposed for 2030 as plausible scenarios for the purpose of assessing the potential benefits of a regional market. Are these portfolios reasonable for that purpose, and if no, why?

Comment: The proposed scenarios are inadequate and must be revised.

Scenario 2 should retain the current footprint for PCC 1 compliance under the California RPS program

It is unclear from the E3 presentation whether Scenario 2 will maintain current RPS requirements that tie PCC 1 eligibility to a showing of direct delivery of renewable energy without substitution into the current CAISO footprint. Scenario 2 should assume the continued existence of this requirement even if a single CAISO-PAC balancing authority is created for operational purposes. The purpose of Scenario 2 is to retain existing "Business as Usual" (BAU) renewable energy procurement policies and isolate the other changes in costs and benefits associated with other consequences of regional expansion. This approach reflects BAU practice because there is no basis for assuming that the California Legislature would otherwise modify the RPS PCC rules.

The E3 study does not consider the potential for existing renewable resources in the Western US and Canada to satisfy California RPS requirements and thereby reduce the demand for the development of new renewable generation

Scenario 3 assumes that RPS PCC 1 compliance can be satisfied by any resource connected, or delivering directly, to the combined CAISO-PAC balancing authority without any need to demonstrate direct delivery of the energy to California. The E3 scenarios assume that incremental procurement for each of the identified Scenario 3 resource portfolios will come from newly developed resources either in California or the WECC. As it relates to resources located outside the current CAISO footprint, this assumption was not tested against current renewable energy market conditions. There may be significant quantities of existing surplus renewable generators in the WECC that are not selling output used for any other state compliance obligation and can sell their output (or have their output resold) to California LSEs.

E3 should explicitly model the potential for existing resources to satisfy part of California's RPS targets under the relaxed PCC 1 requirements associated with Scenario 3. The extremely low price of PCC 3 RECs in the current market (≤$1/MWh) indicates significant surpluses of existing resources in the WECC. E3 must consider the potential for such surpluses from resources located in either the PAC Balancing Authority, or in any adjacent balancing authority that can deliver directly to the PAC footprint (including Colorado and any Canadian provinces), to substitute for new resource development in Scenario 3.

As part of this effort, E3 should analyze the extent to which approximately 1,500 MW of existing wind operating in Alberta could qualify as PCC 1 renewable energy under Scenario 3. Moreover, PacifiCorp currently manages almost 2,000 MW of existing PURPA contracts and has requests for contracts from another 3,700 MW of eligible

QFs in Idaho, Utah, Wyoming and Oregon. (*Direct testimony of Paul Clements of Rocky Mountain Power to Utah PSC, May 11, 2015, pages 10-11*) Much of the output from these QFs could be resold to California LSEs as RPS-eligible output if the PCC 1 eligibility rules are modified consistent with Scenario 3. In addition, significant quantities of existing windpower in the northwest may be available as PCC 1 under Scenario 3.

Absent this type of comprehensive analysis of existing regional renewable energy supply not used to meet RPS or clean energy targets in other states, the SB 350 study may dramatically overestimate the potential for new generation under Scenario 3.

3. To develop the five renewable portfolios the RESOLVE model makes a number of assumptions resulting in a mix of renewable and integration resources for the scenario analysis (rooftop solar, storage, retirements, out of state resources etc.) Do you think the assumptions associated with developing the renewable portfolios are plausible? If no, why not?

Comment: The assumed resource mix is not reasonable under the five portfolios identified by E3.

<u>Study must consider latest RPS compliance positions of various types of California LSEs through 2030 and make realistic assumptions about their likely procurement activities</u>

The study parameters do not suggest any effort to investigate or analyze the extent to which various California LSEs may actually procure resources consistent with the portfolios assumed in the modeling. Three key assumptions are that (1) there is a substantial amount of unmet RPS need by major Investor Owned Utilities (IOUs), (2) other non-IOU California LSEs are likely to sign large volumes of long-term contracts for new Wyoming and New Mexico wind, and (3) this need must be satisfied exclusively or primarily with renewable resources that qualify for PCC 1 treatment. **The study parameters will not reflect reality if these assumptions are left unmodified.**

The study should review the RPS procurement plans and annual compliance reports submitted by the IOUs, Community Choice Aggregators (CCAs) and Electric Service Providers (ESPs) to the California Public Utilities Commission (*see filings in Rulemaking 15-02-020*). These documents contain valuable information that can be used to determine the extent of net short positions by each LSE and the portion of the net short position through 2030 that could be satisfied using PCC 2 and PCC 3 resources. Since PCC 2 and PCC 3 procurement can constitute up to 25% of total RPS compliance (or 12.5% of retail sales beginning in 2031), a review of the net short positions may reveal substantially less procurement appetite by the major IOUs than assumed in the E3 study parameters. An analysis that takes this information into account may also show that the three major IOUs can satisfy most or all of their unmet RPS needs through 2030 with few or no incremental PCC 1 procurement. In this event, the study may find that existing RPS requirements (including the PCC 1 delivery footprint) need not be modified to accommodate significant reliance on out of state wind energy to serve unmet RPS need.

Moreover, the RESOLVE model does not appear to consider the different procurement strategies of smaller LSEs such as CCAs, ESPs and smaller Publicly Owned Utilities. These smaller LSEs have disproportionately large renewable net short positions relative to the 50% requirement but are the least likely to execute significant quantities of long-term contracts with Wyoming and New Mexico wind facilities. Because the RESOLVE model assumes that all LSEs operate like large IOUs, there is a significant disconnect between the assumed procurement portfolios and the actual resources likely to be procured.

Due to the very short turnaround time between the February 8th CAISO workshop and the February 19th deadline for comments, TURN is unable to summarize the supporting data on LSE renewable net short positions from recent RPS compliance filings in these comments. The CAISO and its contractors should perform this work and ensure that the results are incorporated into the modeling. Failure to incorporate this information would render the modeling seriously deficient and disturbingly disconnected from the real world.

<u>Significant quantities of out-of-state renewable energy should be assumed to qualify as PCC 1 products under Scenarios 1 and 2</u>

The E3 study should assume that significant quantities of out-of-state renewable power can qualify as PCC 1 RPS resources under both Scenario 1 and Scenario 2. While the E3 presentation identifies up to 2,000 MW of Wyoming and New Mexico wind projects under Scenario 1 and 2 that would be directly procured by California LSEs as PCC 1 resources, these numbers appear to be low in light of recent developments.

In late 2015 and early 2016, Southern California Edison (SCE) executed contracts for 622 MW of new wind capacity in New Mexico that will provide a PCC 1 product via dynamic transfers to CAISO. (*SCE Advice Letters 3360-E and 3299-E*) These resources will provide renewable energy equivalent to almost 2% of SCE's total retail sales. The study should recognize the fact that these contracts reveal a substantially greater ability to directly import renewable energy into California that qualifies as a PCC 1 product under the current RPS rules than E3 assumes in Scenarios 1 and 2.

Although the study assumes that the Los Angeles Department of Water and Power (LADWP) Balancing Area joins the new regional CAISO, there is no mention of the fact that LADWP is developing plans to import a large quantity of wind from Utah and Wyoming under Scenario 1 (BAU) once the coal-fired Intermountain Power Plant is retired in the mid-2020s. LADWP maintains 2,400 MW of dedicated DC transmission with the ability to directly import intermittent renewable energy from the current PacifiCorp East footprint into California. As a result, LADWP and other Southern California POUs are likely to procure large quantities of Wyoming wind under current RPS rules (Scenario 1) and do not require changes envisioned in Scenario 3 to successfully access these remote wind resources. Although TURN does not support including LADWP in the SB 350 analysis, CAISO cannot include this BA in the study while simultaneously ignoring the existence of dedicated interstate transmission that is likely to be repurposed to enable renewable energy imports absent CAISO regional expansion.

4. The renewable portfolio analysis assumes certain costs and locations for the various renewable technologies. Do you think the assumptions are reasonable? If no, why not?

Comment: The analysis makes problematic assumptions regarding the cost and location of various renewable technologies.

Estimates of behind the meter solar in California may be low

The E3 presentation identifies 14.6 GW of "rooftop PV" assumed in California by 2030 and asserted at the February 8th workshop that this resource "doesn't count" for RPS compliance. (*E3 presentation, slides 16-17)*. The study must be revised to justify the total penetration estimates, ensure that load forecasts are reduced accordingly (to reflect behind the meter solar output), and clarify that the RECs generated by these systems can be certified and would then be eligible for RPS compliance as PCC 3 resources.

The E3 forecast should also be transparently compared to the PacifiCorp benefit study assumption that "8,400 GWh of behind-the-meter solar" would be online by 2030. (*PacifiCorp benefits study technical appendix, pages 17-18)*. It is not obvious whether the assumptions in that study are similar to, or different from, the estimates proposed by E3 since there is no indication as to whether the 8,400 GWh assumption is incremental to the current installed base or represents the total annual production in

2030 from all behind the meter solar in California.

Currently, the three IOUs report approximately 3,550 MW of Net Metered PV either in service or in queue for installation (SDG&E ~500 MW / PG&E ~ 1700 MW / SCE ~ 1350 MW) with the Net Energy Metering 1.0 cap of 5,250 MW expected to be exceeded by mid-2017. If recent trends continue, total deployments by 2030 would significantly eclipse the 14.6 GW estimate. At a minimum, E3 should consider a more aggressive behind the meter deployment scenario consistent with recent adoption trends.

Estimated cost of solar is not consistent with observed market transactions

The E3 study parameters assume that solar PPAs "for 2015 delivery" are expected to cost between $68-82/MWh, anticipates an 8% cost reduction by 2020, and presumes that the federal ITC and PTC "roll off in 2017" (*E3 presentation, pages 25, 28, 29)* This range of pricing does not reflect observed and publicized market transactions by California LSEs and does not recognize the recent extension of the ITC and PTC. The study will not be credible if it models prices that are divorced from real-world experience.

A recent survey found publicly reported prices for new PPAs with California solar facilities are in the range of $50/MWh and levelized prices for Nevada solar facilities have been as low as $40/MWh. (*Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, Lawrence Berkeley National Laboratory, September 2015, page 34)* Some recently observed transactions include $51.97/MWh and $53.75/MWh PPAs between the Southern California Public Power Authority and two solar developers (8minutenergy and sPower) as well as a 25 MW PPA between the Palo Alto Utilities Board and Hecate Energy for solar in Los Angeles County with a commercial online date of 2021 priced at $36.76/MWh (https://www.cityofpaloalto.org/civicax/filebank/documents/50532)

The E3 study should revise its forecast of solar costs to be consistent with observed market transactions rather than relying upon the RPS Calculator. To the extent that assumed prices deviate significantly from transactions that have been reported by legitimate buyers and sellers, the E3 study will not produce results that reflect a realistic view of either the Base Case or Scenarios 2 and 3.

Cost of new PacifiCorp Gateway transmission should be assumed in the Base Case (Scenario 1), with no allocation to CAISO customers, and in Scenarios 2/3

The E3 scenarios presume that 3,000 MW of new Wyoming wind, and 3,000 MW of New Mexico wind, will be developed in Scenario 3 subject to the construction of new transmission. (*E3 presentation, pages 21-22)* The study assumes that because no new transmission is constructed in Scenario 1 (BAU), there is "no increase in availability of out-of-state resources". (*E3 presentation, page 8*)

The study fails to consider the fact that PacifiCorp has already committed to develop the four new Gateway transmission projects that appear to be the key network improvements needed to accommodate the 3,000 MW of new Wyoming wind. (*PacifiCorp 2015 Integrated Resource Plan, pages 199-200*) PacifiCorp's IRP never indicated that these transmission additions would occur only in the event of CAISO regional expansion and are sought by PacifiCorp to improve flows within the PACE and PACW regions. The E3 study should therefore assume that the full suite of Gateway transmission additions also occur in Scenario 1 but that the costs are not allocated to CAISO customers via the Transmission Access Charge (TAC). In Scenarios 2 and 3, E3 should consider results where some of the transmission costs are allocated to CAISO via the TAC.

Similarly, it would be inappropriate to allocate any new transmission costs to CAISO via the TAC for network improvements needed to facilitate New Mexico wind being procured by California LSEs. Since there is no current proposal to have any of the New Mexico or Arizona utilities join the CAISO, it is not appropriate to assume that transmission costs incurred by these utilities are allocated to the TAC collected from California customers. Under the current framework, any new transmission costs associated with New Mexico wind would be borne by the wind developer and incorporated into PPA pricing.

The price of Wyoming and New Mexico wind should be adjusted to account for net costs resulting from the resale of energy into local markets

In its assessment of Wyoming and New Mexico wind, the E3 study approach appears to rely exclusively on the "gross costs" associated with PPA payments made to the renewable generators. This approach ignores the fact that, under the CAISO energy market, LSEs procuring renewable energy will also receive *revenue* equal to the Locational Marginal Price ("LMP") at each facility's point of delivery.

Since the E3 model does not assume that the energy from these facilities would be scheduled directly into California, the point of delivery should be a market hub or node close to the facility itself. Revenues from the sale of energy at these locations should be netted against PPA costs to determine the total cost and value of the resources. Any estimate of the relative costs of renewables within regions of a larger Balancing

Authority must also estimate these offsetting revenues to compute the "net costs" of renewables under different scenarios.

The E3 Study must further ensure that the estimation of LMPs in Wyoming takes into account a scenario where 4,000 MWs of new intermittent generation is developed in that region with coincident production profiles. There may be non-trivial impacts on market prices in hours when these wind projects are liquidating energy that would change the net cost to California LSEs.

Address Other Alternatives to Gain Access to Wyoming and New Mexico Wind

The E3 study should also address the other proposals to build transmission to provide access to out-of-state wind resources, specifically, the proposed TransWest Express and Zephyr transmission lines that would provide access to Wyoming wind and the proposed SunZia transmission line that would provide access to New Mexico wind. There does not appear to be any effort to review these alternatives and assess the potential impacts on system operations and costs.

Cost of out of state resources should be estimated with, and without, the conveyance of GHG allowances

Under the Clean Power Plan (CPP), states may design their own mass-based compliance plans and have the flexibility to assign GHG allowances to generators without any specific restrictions. In the event that other Western states choose not to allocate free GHG allowances to new renewable generation, the purchase of renewable energy from such resources by California LSEs would not include any GHG allowance value. If these resources are allocated GHG allowances, they would presumably be conveyed to California LSEs and could be either retired or resold. The study should model the value of these resources with, and without, any accompanying GHG allowances.

5. **The renewable portfolio analysis makes assumptions about the availability and quantity of out-of-state renewable energy credits ("RECs") to California. Do you think the assumptions are plausible? If no, why not?**

Comment: The study does not accurately reflect the availability of existing and new resources to provide PCC 1, PCC 2 and PCC 3 resources.

As explained in response to Question 2, the analysis fails to consider the potential for existing surplus renewable resources in the West to satisfy California RPS requirements instead of new renewable generation. As explained in response to

Question 3, the analysis also fails to account for the relative compliance positions of various LSEs and the allowances for PCC 2 and PCC 3 resources under the existing RPS program rules.

6. The renewable portfolio analysis makes assumptions about the ability to export surplus generation out of California (i.e., net-export assumptions). Do you think these assumptions are reasonable? If no, why not?

Comment: The proposed export assumptions appear to represent a reasonable range of future possibilities for exporting power from the CAISO.

7. Does Brattle's approach for analysis of potential impact on California ratepayers omit any category of potential impact that should be included? If so, what else should be included?

Comment: It is not clear whether the approach is reasonable.

Given Brattle's proposal to use multiple methods for valuing benefits, TURN is concerned that some of the benefits could be double-counted (*Brattle presentation, page 8*). As noted in response to Question 4 above, the computation of ratepayer impacts must also include an assessment of LMPs in the local area or node where renewables are located, consistent with the CAISO's own Transmission Economic Assessment Methodology (TEAM). Finally, as noted extensively above, TURN has significant concerns about the WECC-wide modeling construct and other assumptions that will develop inputs into the ratepayer impact computations. Finally, it is not possible yet to comment on Brattle's actual computation of the several listed benefits.

8. Are the methodology and assumptions to estimate the potential impact on California ratepayers reasonable? If not, please explain.

Comment: No.

As explained in response to Question 4, the study should therefore assume that the four Gateway transmission projects proposed by PacifiCorp occur in Scenario 1 but without any costs being allocated to CAISO customers via the Transmission Access Charge.

9. The regional market benefits will be assessed based assuming a regional market footprint comprised of the U.S. portion of the Western Interconnection. Do you believe this is a reasonable assumption for the purpose of this study? If not, please explain.

Comment: This approach is unreasonable, implausible and fundamentally unsound.

The Brattle study parameters assume that the entire WECC (excluding the Canadian provinces) operates as a single balancing authority. This approach is fundamentally inconsistent with the proposal to merge the CAISO and PAC balancing authorities and would instead model a scenario where all of the 38 Balancing Authorities in the WECC commit to be part of a single regional BA. No such commitments have been made and the odds of many of the western utilities and power marketing agencies (such as Bonneville Power Authority, LADWP/SCPPA, and others) joining the CAISO are close to zero. Moreover, there is no indication that the Brattle results will show the allocation of benefits amongst the various BAs which may frustrate efforts to understand the extent of benefits that current CAISO customers should expect to realize.

The study should only model the combined CAISO-PAC balancing authority. Failure to limit the analysis to these areas renders the results fundamentally irrelevant to the question of whether the proposed near-term expansion should proceed. Limiting the analysis to the instant proposed expansion is the only way to proceed with integrity so that the results can be reviewed by Legislative leaders to determine whether CAISO's desired governance changes are reasonable. A decision not to enforce this limitation is likely to undermine any chance for timely approval of such changes by the Legislature and force CAISO and its contractors to redo the entire study using more reasonable participation parameters.

10. For the purpose of the production cost simulations, Brattle proposes to use CEC carbon price forecasts for California and TEPPC policy cases to reflect carbon policy implementation in rest of WECC. Is this a reasonable approach? If not, please explain.

Comment:

It is not clear what is meant by the term "TEPPC policy cases" in this question. TURN is familiar with the existence of "TEPPC Common Cases". A search on WECC's website for this term will yield a number of hits. However, the concept of "TEPPC policy case" or "cases" does not seem to appear on WECC's website (wecc.biz). Brattle should clarify what is meant by this term.

11. BEAR will be using existing economic data, and generation and transmission data from E3, the CAISO, and Brattle. These data are currently being developed. Are there specific topics that you want to be sure to be addressed regarding these data?

Comment:

12. The economic analysis will focus on the electricity, transportation, and technology sectors to develop the economic estimates of employment, gross state product, personal income, enterprise income, and state tax revenue. These results will be further disaggregated by sector, occupation, and household income decile. Do you think these sectors are the appropriate ones on which to focus the job and economic impact analysis? If no, why?
Comment:
13. Under the proposed study framework, both economic and environmental impacts of disadvantaged communities will be studied. Based on the study overview do you think this satisfies the requirements of SB350?
Comment:
14. The BEAR model will evaluate direct, indirect, and induced impacts to income and jobs, including those in disadvantaged communities. Do you think additional economic analysis is required? If yes, what additional analysis is needed and why?
Comment:
15. The environmental analysis will evaluate impacts to California and the west in five areas – air quality, GHG, land, biological, and water supply. Do you think additional environmental analysis is required? If yes, what additional analysis is needed and why?
Comment:
16. The environmental analysis presentation identified a number of potential indicators for the various impacts. Are the indicators sufficient? If no, what additional indicators would you suggest?

Comment:

17. Other

Comment:

Analysis of GHG emissions should isolate impacts from the Energy Imbalance Market

Any analysis of GHG emissions under the various Scenarios should separately assess the impact of the Energy Imbalance Market. In the fall of 2015, TURN requested that CAISO model the GHG impacts of the entire Energy Imbalance Market to accompany the economic analysis provided on a quarterly basis. CAISO management indicated that such an analysis was possible. No analysis has yet been provided. The SB 350 study should perform a rigorous analysis that highlights the specific GHG emissions impacts of EIM (including all expected new participants) without regional expansion (Scenario 1).

Accelerated schedule for SB 350 studies is problematic and arbitrary

The highly accelerated schedule for soliciting feedback on the study parameters is tied solely to CAISO's decision for a complete draft of the results to be available by late April. There is no reason for this tight deadline given the fact that SB 350 does not require any such studies to be submitted to the Legislature until December 31, 2017. Rather than rush to complete studies that may suffer from fatal flaws, CAISO should take time to review and incorporate stakeholder feedback and provide an update with another chance for comment prior to moving forward with the actual modeling.

Full workpapers, models and other relevant documentation must be provided for review

CAISO and its contractors should release full workpapers, all models, and any relevant documentation used to develop the study results consistent with the requirements of SB 350. All electronic workpapers should be provided in Excel-compatible format with data and formulae intact, and parties should not need to gain access to proprietary tools to read the inputs and outputs of the various models. Access to confidential data, if used, must be provided to parties willing to sign reasonable Non-Disclosure Agreement.