Comments of Powerex Corp. on SB 350 Study Preliminary Results

Submitted by	Company	Date Submitted
Clarke Lind 604.891.6034	Powerex Corp.	June 22, 2016

Powerex appreciates the opportunity to comment on the preliminary results of the Clean Energy and Pollution Reduction Act Senate Bill 350 Study ("Preliminary Results"), presented May 24-25, 2016.[1]

Powerex believes that a regional organized electricity market has the potential to provide positive net benefits to stakeholders in California and potentially in other western states. The changes necessary to transform the current CAISO into a regional organized market—and for entities in the region to join this regional market—are significant, complex, and potentially controversial. Constructive dialog will benefit from—and, in fact, requires—sound quantitative analysis of the potential benefits, costs and risks of such a transformative undertaking.

Powerex seeks to better understand three primary aspects of the Preliminary Results:

- The assumed regional market footprint in 2030—specifically, whether or how the reasonableness of that assumption can be tested.
- The investment cost savings analysis—specifically whether access to load and flexible generation in other BAAs, which drives these savings, is assumed to occur without compensation to the external entities that fund those assets.
- The production cost savings analysis—specifically, how the analysis projects the benefits associated with more efficient day-ahead inter-BAA transactions, and how the analysis recognizes the extent to which some of these efficiencies can be achieved through the EIM.

Issue 2b: Assumed Regional Market Footprint in 2020 and 2030

The Preliminary Results identify a tenfold range in the benefits to California consumers, with the benefits depending on the assumed scope of the regional market footprint.[2] This indicates that the projected benefits to California consumers are highly sensitive to how many of the region's BAAs elect to join a regional market. Moreover, most of the California benefits from a "CAISO+PAC" scenario are due to simply spreading Grid Management Charges across a larger footprint that includes both California and

[1] These comments cite primarily to the May 24, 2016 presentation ("May 24 Presentation"), *available at* http://www.caiso.com/Documents/Presentation-May24_2016-SenateBill350Study-PreliminaryResults.pdf.
[2] May 24 Presentation at 8.

PacifiCorp customers,[3] rather than to new efficiency gains. Thus the projected benefits of an expanded footprint may be highly sensitive to not only the size of the footprint, but also which specific BAAs decide to join.

Powerex seeks to understand whether any kind of analysis was performed, or could be performed, to test the reasonableness of the assumptions regarding which BAAs could be expected to identify sufficient, positive net benefits to join a regional market footprint. It appears that this type of analysis is possible given the work that Brattle has already completed. For instance, it appears that Brattle's projections of production cost savings were performed for each of the BAAs in the assumed regional footprint.[4] Additionally, Brattle has projected capacity diversity savings that would be achieved in non-California BAAs as a result of optimizing dispatch and reserves over a larger regional footprint.[5] And less complex projections, such as the Grid Management Charges that would be allocated to non-California BAAs, could also be estimated.[6] It therefore appears possible to use the existing modeling results to estimate the projected net benefits that would be realized by each BAA that is assumed to participate in the regional organized market in 2030. This would provide stakeholders with some ability to verify that the analysis indeed projects positive net benefits for each BAA that is assumed to participate in the regional organized market. If this is not the case, then the assumption regarding the size and composition of the regional market footprint may need to be revisited.

This type of assessment could also be used to identify whether there is a minimum viable size for a regional organized market. For example, further analysis might project that a large fraction of the net benefits to California consumers would be achieved even if only, say, five specific BAAs elect to join. This might provide a more promising outlook for regionalization than if a very high degree of participation was necessary to provide significant benefits to California ratepayers.

Given how sensitive the projected benefits are to the scope of the regional market footprint, Powerex believes the SB 350 study would benefit from additional efforts to test the validity of the 2030 participation assumptions and to identify whether significant net benefits would still be projected under scenarios involving more limited participation.

Issue 2e: The Economic Analysis of Capital Investment Savings.

The Preliminary Results project savings to California consumers of $680-800 million per year of avoided capital investment costs compared to the Current Practice scenarios.[7] These projected savings appear to be driven by two broad assumptions: (1) access to load and flexible generation outside of California, which reduces the investment necessary to achieve California's RPS target; and (2) the ability to meet California's

[3] *Id.* at 8, 108 (showing $39 million savings to California ratepayers in 2020 due to Grid Management Charge savings, compared to total savings to California ratepayers of $55 million).
[4] *Id.* at 147.
[5] *Id.* at 101.
[6] *Id.* at 204.
[7] *Id.* at 50.

RPS target using more cost-effective remote external renewable resources, such as wind in Wyoming or New Mexico.

<u>Questions related to investment cost savings due to access to flexible capacity outside California</u>

The results of Scenario 2 indicate that a regional energy market can reduce the investment necessary to achieve California's RPS targets. For instance, to meet the 50% RPS target by 2030, E3 calculates that California will need to add 16,652 MW of renewable generation under the Current Practice scenario (Scenario 1a).[8] But a WECC-wide regional market would allow this same target to be met with 15,370 MW of renewable resource additions.[9] This is because the regional market results in more efficient exports of excess renewable production, reducing curtailments, and hence reducing the need to "over-build" renewable capacity in order to meet the RPS target. Moreover, in Scenario 2, in-state investment in energy storage is reduced from 972 MW to 500 MW.[10]

All told, E3 projects that California consumers will realize $680 million per year of savings associated with reduced investments necessary to achieve the 50% RPS target by 2030 under Scenario 2. This is the single largest category of benefits in the Preliminary Results.

Access to load and flexible generation capacity outside of the existing CAISO footprint appears to be the key to reducing the investment necessary to meet California's RPS target. But the E3 study does not explicitly state how those benefits will be allocated between California ratepayers and the ratepayers whose resources and participation make these savings possible. ***This appears to be a significant gap in the analysis, as it excludes the costs incurred in contracting for and compensating resources in external regions that will be relied upon to reduce the level of investment needed in California.***

Consider two approaches to managing California renewable output: invest in battery storage within California, or expand the market footprint to include external flexible storage hydro generation and load that is able to provide equivalent quasi-storage services. The Preliminary Results explicitly consider both the *capital* cost to build the battery storage (via the E3 renewable portfolio analysis) as well as the *variable* cost of charging and discharging the battery (via Brattle's production cost simulation). But in the alternative scenarios—in which access to the combination of external flexible generation capacity, external load, and external hydro storage reservoirs reduces the need to build in-state battery storage—there is no recognition of the need to compensate for the capital investments associated with that external quasi-storage capability. The external resources are part of the Brattle analysis of variable production costs, but they are not included in any estimate of capital costs. It appears simply to be assumed—though not explicitly stated—that the opportunity for utilities and other entities funding these external resources to recover their variable operating costs (plus

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[8] *Id.* at 44. The amounts are in addition to the amount necessary to achieve the 2020 RPS target or 33%.
[9] *Id.*
[10] *Id.*

perhaps some modest production cost savings) will be sufficient to ensure those flexible resources are made available and can be relied upon to balance the variations in California's renewable resources.

It may therefore be important to evaluate not only whether each BAA assumed to be in the regional market footprint is projected to realize positive net benefits, but whether those benefits represent an equitable allocation of the total benefits created by that BAA's participation. It is unclear whether BAAs would elect to join a regional market in which they only share in modest production cost savings associated with their participation, while enabling other entities to realize very large investment cost savings, unless those larger savings were also shared equitably.

To better understand this aspect of the Preliminary Results, Powerex would appreciate clarification of the following:

1. Is it assumed that every external resource relied upon to reduce California's investments in renewable resources or storage will continue to be funded only by the ratepayers of the local entity that built it, or will California consumers fund a portion of those capital costs in return for the investment savings those resources provide to California consumers?
2. What specific assumptions are made regarding the level of procurement of flexible capacity and storage resources under each study scenario? For example, does the study assume that external resources merely will *reduce* the quantity of flexible capacity that must be procured and paid for (*i.e.,* without receiving equitable compensation for the services that they provide)? Alternatively, is it assumed that these external resources will *participate* in those programs to meet the required procurement target? How is this reflected in the analysis?
3. What specific assumptions are made regarding whether flexible capacity and quasi-storage services (*i.e.,* provided through a combination of load, flexible hydro generation and hydro storage capacity) located in one BAA are eligible to participate in California's and other states' forward procurement programs for flexible capacity and storage services, respectively? How is this reflected in the analysis?

<u>Questions related to external procurement of renewable resources</u>

Powerex seeks to better understand the connection between a regional organized market and the ability for California to meet its RPS targets using cost-effective external resources such as wind from Wyoming or New Mexico. Specifically, Powerex believes a response to the following questions would be helpful:

1. Is it E3's conclusion that the renewable portfolio in Scenario 3 would not be possible in the absence of a regional organized market?
2. What specific barriers does E3 believe exist that make the renewable portfolio in Scenario 3 impossible without a regional organized market?
3. How, specifically, does E3 anticipate that a regional organized market will overcome those barriers?

4. Has E3 consulted with the California Public Utilities Commission ("CPUC") regarding the potential for expanded procurement of lower-cost renewables from resources outside of California? Has the CPUC confirmed that it, too, believes that such expanded procurement requires a regional organized market?

Issue 2e: The Economic Analysis of Production Cost Savings.

The Preliminary Results project savings to California consumers of $104-523 million per year from reduced production costs.[11] The production cost savings are generally described as arising from more efficient commitment and dispatch of generation across the west than is possible without an organized market. An organized market is also described as necessary to permit the export of excess California renewable generation.[12]

Powerex seeks additional clarity regarding two aspects of the production cost analysis:

- To what extent could the projected benefits of more efficient dispatch be achieved through participation in the EIM? Conversely, what portion of the projected benefits can be achieved only through participation in a day-ahead regional organized market?
- To what extent does the analysis recognize efficient bilateral trading that currently occurs in both day-ahead, multi-hour on-peak and off-peak products and real-time hourly products?

Questions related to identifying the additional benefits of a day-ahead regional organized market over a real-time EIM

The Preliminary Results project production cost savings made by comparing a day-ahead simulation under the Current Practices to a day-ahead simulation under a regional organized electricity market. The production cost analysis does not include any simulation of the day-of or real-time markets.[13]

Powerex seeks to better understand whether such an approach will accurately identify the incremental benefits associated with developing a day-ahead regional organized market. In particular, the production cost savings associated with eliminating hurdle rates, pancaked wheeling charges, or other trading "friction" have also been cited as benefits of participation in the EIM, which operates only in the real-time timeframe.[14] The potential for increased exports to reduce the need to curtail California renewable production was similarly cited as something that the EIM would achieve.[15]

There appears to be an important distinction between (1) a day-ahead market that achieves efficient dispatch that would not have occurred at all; and (2) a day-ahead

[11] *Id.* at 94.
[12] *Id.* at 88.
[13] *Id.* at 84.
[14] *See, e.g.,* Energy and Environmental Economics (E3) *PacifiCorp-ISO Energy Imbalance Market Benefits* at 6 (March 13, 2013)*, available at* http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.
[15] *See, e.g., id.* at 7.

market that merely achieves day-ahead dispatch efficiencies that would have otherwise been achieved in real-time through operation of the EIM. The former is a genuine additional benefit achieved only through implementation of a day-ahead organized market; the latter does not represent any additional benefits, but simply shifts them from the real-time EIM to the day-ahead market.

To better understand how this issue may affect the Preliminary Results, Powerex believes exploring the following issues would be helpful:

1. What portion of the production cost savings projected by Brattle could be achieved if the BAAs in the assumed regional market footprint participated only in the EIM?
2. What methodology was used to distinguish between *incremental* production cost savings achieved under a "day 2" market design (including both a day-ahead and real-time market) and those production cost savings that could be achievable through the EIM?

<u>Questions related to identifying the additional benefits of a day-ahead regional organized market over bilateral day-ahead transactions</u>

The Brattle production cost analysis simulates the barriers to perfectly efficient bilateral interchange transactions by applying certain hurdle rates and wheeling charges. This tends to prevent otherwise economic re-dispatch of resources among BAAs outside of the organized market as well as between external BAAs and the organized market footprint itself. The hurdle rates and wheeling charges are introduced into the simulation to act as "friction" in the Current Practice scenarios, but are removed from the regionalization scenarios, which are then permitted to achieve maximum efficient dispatch.

The hurdle rates added into the Current Practice scenarios include:

- "Pancaked" wheeling rates based on the hourly non-firm tariff rate for off-peak use, which range from $0.7/MWh to $12.2/MWh, depending on the BAA;
- $1/MWh administrative charge;
- $1/MWh trading margin;
- $4/MWh adder for unit commitment; and
- Carbon liability based on "unspecific source" rate for imports into California.[16]

Powerex seeks to better understand the reasonableness of the hurdle rates selected by Brattle in this analysis. In particular, the wheeling charges would benefit from further examination, since they are based on a rate for hourly non-firm point-to-point service. Powerex has previously pointed out that the majority of interchange transactions in the west use transmission service that is purchased for durations longer than one hour. A transmission customer that has purchased yearly service, for instance, will not incur the hourly wheeling charge assumed in the Brattle analysis. Based on Powerex's experience participating in the bilateral markets, it is simply incorrect to assume that

[16] May 24 Presentation at 142.

interchange transactions occur only if regional price differences exceed the hourly non-firm transmission rate.

This is not intended to suggest that Powerex believes bilateral trading is as efficient as an organized market. To the contrary, Powerex firmly believes that organized markets can facilitate additional inter-BAA transactions that simply would not occur under a bilateral framework. But the circumstances in which an organized market can achieve these improvements need to be carefully and specifically articulated. A generalized assumption that *all* bilateral trading activity is less efficient than centralized market transactions will not provide an accurate assessment of the benefits of an organized market.

In particular, Powerex believes that existing bilateral trading activity is highly efficient *for the products that are actively traded*. In other words, the trading "frictions" or hurdle rates that apply to day-ahead transactions for standard blocks of 8, 16 or 24 hours should be relatively low. Similarly, the trading "frictions" that apply to standard real-time hourly products should also be relatively modest. On the other hand, there is considerably less liquidity in custom products or day-ahead single-hour bilateral transactions, or in real-time sub-hourly transactions, implying a relatively high trading "friction." To better understand the extent to which the Preliminary Results include a reasonable and realistic representation of bilateral trading in the west, Powerex believes a response to the following questions would be helpful:

1. What analysis did Brattle perform regarding the actual use of hourly non-firm transmission service in the west?
2. How did Brattle conclude that "marginal import and export transactions … primarily rely on hourly services"?[17]
3. What is the basis for Brattle's assumption that interchange transactions incur a cost of $1/MWh in administrative charges?
4. What is the basis for Brattle's assumption that bilateral interchange transactions require a trading margin of at least $1/MWh, but that no trading margin is required in an organized market?
5. Please explain Brattle's assumption that interchange transactions incur a $4/MWh "adder" for unit commitment? What is the basis for this assumption?
6. What sensitivity analyses did Brattle perform to test how each of the above assumptions impact the Preliminary Results?[18]
7. Does Brattle's production cost analysis apply the same hurdle rate assumptions to all transactions with a BAA that is not in the regional market footprint? For instance, does the Brattle analysis apply the same hurdle rate to an external resource that is committed and dispatched for 24 hours that it does to an external resource that is dispatched for only a single hour?

[17] *Id.* at 143.

[18] Powerex notes that Scenario "1b," while described as employing "low bilateral re-export hurdles" (May 24 Presentation, at 25) only increases the quantity of potential exports from California, but appears to still apply all the hurdle rates as Scenario 1a.

8. Did Brattle consider alternative modeling methodologies that can distinguish the potential savings from more efficient day-ahead hourly transactions, over and above existing efficient multi-hour bilateral transactions?