Comments of Powerex Corp. on Draft Regional Resource Adequacy Framework Proposal

Submitted by	Company	Date Submitted
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Powerex appreciates the opportunity to comment on CAISO's December 1, 2016 Regional Resource Adequacy ("RA") Draft Regional Framework Proposal ("Draft Proposal"). The Draft Proposal identifies several recommended changes to the existing RA framework to facilitate the expansion of the CAISO into a multi-state regional transmission organization ("RTO").

Before considering the details of this latest proposal, Powerex believes it is important to highlight that, throughout this stakeholder process, CAISO has limited the scope of this initiative to only those changes necessary to extend the existing RA framework to a multi-state RTO.[1] Thus, it appeared—until this most recent Draft Proposal—that the core requirements of the existing RA framework developed by CAISO and the California Public Utilities Commission ("CPUC") would remain unchanged within the context of a broader RTO market. That is, it was understood each load-serving entity ("LSE") would be required to commit sufficient forward capacity to meet expected peak load plus a planning reserve margin (currently 15%) for uncertainty,[2] with the majority of this capacity procured on a year-ahead basis, and the remainder met on a month-ahead basis. More specifically, each LSE in a regional market would be required to submit an annual plan demonstrating that it had procured forward capacity equal to 90% of its RA requirement for the summer months of the compliance year, and to submit monthly plans demonstrating it had procured 100% of its RA requirement at least 45-days prior to each month, consistent with the existing RA framework.[3] All prior versions of CAISO's regional RA proposals retained these core RA requirements.

Now, more than a year after commencing this proceeding, the current Draft Proposal seeks to make a fundamental departure from the existing RA program in what appears to be an effort to accommodate the current RA practices of certain entities outside California. In particular, CAISO now proposes to permit all LSEs in a regional market to explicitly rely on short-term energy purchases to satisfy up to 10% of their RA requirements. Rather than continuing to require that 100% of an LSE's RA requirement be met through forward

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[1] *See, e.g.,* Cal. Indep. Sys. Operator Corp., Regional Resource Adequacy Straw Proposal at 4 (Feb. 24, 2016) (stating that CAISO "did not intend for this initiative to explore broader changes to the general RA construct").

[2] *See, e.g.,* Cal. Indep. Sys. Operator Corp., Regional Resource Adequacy Revised Straw Proposal at 35 (Apr. 13, 2016) (assuming planning reserve margin of 15%).

[3] 2017 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings (Sept. 20, 2016).

capacity commitments at least one month in advance, CAISO would only require that 90% of the RA requirement be met by the deadline for the monthly resource showing. In effect, the Draft Proposal lowers the current forward RA procurement requirement from 115% of the forecast peak load to just 103.5%.

Although the Draft Proposal does not fully articulate CAISO's rationale for reducing RA requirements across an expanded footprint, its proposal appears intended to accommodate a single entity—PacifiCorp—whose existing approach to resource adequacy would not meet, and is fundamentally out of step with, the current RA requirements of the CAISO and CPUC. As the CAISO Department of Market Monitoring observed earlier in this proceeding, PacifiCorp's integrated resource plan indicates that PacifiCorp relies "on bilateral spot market purchases to meet a significant portion of its peak capacity needs."[4] This characterization is borne out by publicly available data, discussed further below, which shows that PacifiCorp's short-term energy purchases have increase significantly on the days of highest demand across western electricity markets.

Powerex appreciates CAISO's efforts to seek areas in which it can accommodate the practices of external entities seeking to integrate into its footprint. However, in this particular circumstance, developing an RA policy that can accommodate the substantial differences between the current CAISO/CPUC RA framework and the resource planning approach taken by PacifiCorp presents significant issues that must be considered by all LSEs and customers within an expanded RTO footprint. For example, simply applying the existing CAISO/CPUC RA framework to external LSEs, such as PacifiCorp, that have not invested in sufficient capacity to meet the same level of RA requirements—and have instead chosen to accept the reliability risk of relying on the short-term energy markets—will result in increased forward capacity costs for these LSEs if and when they join the expanded RTO. At the same time, departing from one of the core principles that has guided the development of the existing CAISO/CPUC RA program by allowing all LSEs—both new and existing—to "go short" on the forward capacity commitments necessary to ensure reliability would significantly weaken the forward RA commitment requirement. The Draft Proposal effectively adopts this latter approach, as it proposes to not only accommodate PacifiCorp's continued reliance on short-term energy purchases to serve its approximately 10,000 MW of peak demand, but would extend that same approach to the approximately 60,000 MW of peak demand of the expanded regional market. Powerex believes that CAISO's proposal represents a material departure from the core principles of the existing RA framework, with the potential for far-reaching consequences that should be carefully considered by all stakeholders.

Powerex believes it is important to recognize that the existing RA framework was developed through an extensive process conducted by the CPUC and CAISO. That process included substantial discussion and analysis regarding the appropriate design of

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[4] Comments of Department of Market Monitoring on Regional Resource Adequacy Revised Straw Proposal at 2 (May 16, 2016) ("DMM Comments").

forward contracting requirements necessary to ensure supply adequacy under a range of system conditions. That framework currently defines RA contracting requirements equal to 115% of forecast peak demand, which must be fully met on at least a month-ahead basis. This RA framework is now at a critical juncture. As CAISO explores regionalization of its organized market, should PacifiCorp and other new potential entrants be held to the same level of forward capacity procurement (and hence reliability) as required under the existing CAISO/CPUC RA policies? Or should the existing RA framework be weakened based on the practices of the first entrant into a regional market, even if those practices may raise significant reliability risks for California LSEs and their ratepayers?

In the remainder of these comments, Powerex addresses the following points:

- The Draft Proposal would permit up to 10% of the RA requirement to be met through short-term bilateral purchases. This effectively reduces the forward capacity contracting requirement from the current level of 115% of forecast peak demand to 103.5% of peak demand.

- No evidence has been put forward to support the Draft Proposal's reduction in the forward RA contracting requirement. Powerex's examination of available public data indicates that there may be occasional periods of scarcity in the short-term markets, reflecting the lack of regional coordination to ensure that installed capacity is actually committed to be available and deployable through the short-term markets.

- The Draft Proposal claims that reliance on short-term energy markets to meet peak demand is the practice of many entities in the west, though no analysis has been offered to support this characterization. To the contrary, Powerex's review of public data indicates that PacifiCorp is one of the few—or perhaps the only—load serving entity in the region that regularly relies on making significant short-term purchases to meet its peak demand.

- Powerex believes that the proposed departure from requiring the entire RA requirement to be contracted on a forward basis at least one month ahead needs to be supported by objective analysis and vetted through robust stakeholder processes at both the CAISO and CPUC, similar to the extensive CAISO and CPUC proceedings that led to the existing RA design.

I. The Draft Proposal Represents A Significant Reduction In The Forward RA Commitment Requirement

The purpose of an RA program is to require that sufficient capacity is built, maintained, and committed sufficiently in advance to ensure that CAISO has adequate resources available to deploy through its markets to reliably serve load under a wide array of circumstances. In the near-term, RA programs safeguard reliability by ensuring that sufficient existing resources are committed to be available during the compliance year (or month) by offering their capacity into the CAISO markets. This, in turn, ensures that the

CAISO has adequate resources available to dispatch to meet demand. In the longer term, RA programs provide financial incentives to maintain existing resources and to develop new resources by providing market-based compensation to the physical capacity resources whose availability is necessary to ensure reliability. In this respect, RA programs help to address the “missing money” problem by supplementing the revenues earned in short-term organized markets (which are typically not sufficient to ensure full recovery of the fixed costs of such resources), thereby helping prevent the premature retirement of existing resources and encouraging the development of new resources.

To date, California’s current RA framework has sought to achieve these objectives by requiring LSEs to procure, on a forward basis, capacity equal to their forecast peak demand plus a planning reserve margin, which is currently 15%. LSEs are required to demonstrate that they have procured at least 90% of their RA requirement a year in advance, and must demonstrate they have procured 100% of their RA requirement at least 45-days prior to each month.

In contrast to the current requirements, the Draft Proposal now proposes to explicitly permit LSEs to rely upon spot market energy purchases, including day-ahead energy purchases, to satisfy up to 10% of their RA requirement. Simply put, the proposal lowers the RA requirement that must be secured in advance of when the capacity may be needed, allowing LSEs to rely on short-term purchases of energy instead.

Powerex believes that there is no meaningful distinction between lowering the portion of the RA requirement that must be secured in advance, as proposed, and simply lowering the RA requirement altogether. Either way, the end result is the same: LSEs will no longer be required to demonstrate forward capacity commitments equal to 115% of peak load on a month-ahead basis, and will instead be required to demonstrate forward capacity commitments for as little as 103.5% of peak load on a month-ahead basis. Since the fundamental purpose of the RA framework is to ensure capacity is committed *before* it is needed, Powerex believes it is inaccurate to characterize the Draft Proposal as doing anything other than reducing the forward RA requirement.

In fact, the Draft Proposal may actually result in forward RA procurement of significantly *less* than 103.5% of forecast peak load. This is because the existing RA framework contains a recognized and material “gap” associated with import RA commitments. More specifically, import RA contracts are not currently required to be linked to physical external resources at the time of RA procurement. As a result, an entity that sells import RA to an LSE does not need to have any physical capacity available at the time it makes the RA commitment, and instead can rely on short-term energy purchases to meet its contractual obligation if, and when, it is called upon to deliver energy. In practice, neither LSEs nor CAISO currently have any way of knowing whether an import RA contract represents a firm commitment of available physical capacity (and the transmission necessary to deliver the capacity to the CAISO) or simply a financial commitment by the seller to procure energy from the short-term bilateral energy markets to meet its contractual obligation to the applicable LSE. Despite having acknowledged this gap in prior draft proposals in this stakeholder process,[5] and despite having previously proposed specific measures to address it, the latest Draft Proposal no longer attempts to tighten the requirements respecting import RA contracts. Rather than taking steps to ensure that all RA commitments, including import RA commitments, represent a firm forward commitment, the Draft Proposal appears to endorse and expand this practice.

II. The Draft Proposal Will Undermine Reliability By Enabling "Leaning" And Discouraging Investment In Capacity

Powerex is concerned that the Draft Proposal presents no evidence or analysis to support the implicit assumption that short-term energy markets can be safely relied upon to supply up to 10% of the peak needs of a regional market. To the contrary, Powerex's examination of available public data calls into question the reliability implications of the Draft Proposal, which would permit a five-fold increase in the reliance on short-term energy markets.

Powerex believes that the Draft Proposal, if adopted, would likely have significant adverse consequences in both the long term and the short term. Over the long term, increased reliance on spot energy markets to meet peak load can be expected to undermine investment in capacity, increasing the risk of service interruptions and reducing reliability. In the near term, the proposal will create a regional market in which entities that have not procured adequate capacity resources to sufficiently meet their needs on a forward basis are permitted to "lean" on the capacity investments made by others, including the California LSEs. In Powerex's view, it is inequitable to design a regional market in which reliability risk is socialized across all users of the regional grid but the financial burden of ensuring that reliability is not. Moreover, such a design may also discourage future participation in a regional market by those entities that seek to maintain a more robust approach to resource planning.

A. PacifiCorp's Approach To Resource Planning May Not Be Scalable To A Regional Organized Market

It has been noted in this stakeholder process that PacifiCorp appears to have been able to rely on the short-term energy markets without experiencing actual reliability events to date. But the critical question is whether PacifiCorp's approach to resource planning can be safely extended to *all* LSEs within an expanded RTO footprint. In effect, the Draft Proposal would allow all LSEs within the regional market footprint to adopt PacifiCorp's approach of "going short" on forward capacity commitments and increase their own reliance on short-term energy markets to meet peak demand. The proposal therefore contemplates not only permitting PacifiCorp to rely on up to approximately 1,000 MW of

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[5] *See, e.g.,* Cal. Indep. Sys. Operator Corp., Third Revised Straw Proposal at 38-39 (Sept. 29, 2016) (expressing concern that lack of clear requirements respecting import RA contracts could be "interpreted as allowing LSEs to demonstrate through RA showings that they have met their RA requirements and move into the operating month without securing these contractual obligations prior [to] the month-ahead timeframe").

short-term energy purchases to meet its peak demand needs, but to also allow California LSEs to rely on additional short-term energy purchases of up to approximately 5,000 MW. Powerex's analysis of publicly available information suggests that the short-term bilateral energy markets in the west may not always be able to cover such a material reduction in forward committed RA capacity in the region.

1. Absent The Formal Forward Commitment Of Capacity, Availability Of Supply In Bilateral Short-Term Energy Markets Could Be Limited

Conventional supply assessments for the WECC confirm that the *installed* capacity base generally exceeds prevailing planning reserve margins. This implies that, on most days, there may be substantial amounts of energy available for purchase in the short-term and the long-term markets. However, prior to reducing the requirement to procure RA on a forward basis, it is necessary to identify circumstances under which energy supplies in the short-term markets may be limited. Despite the fact that surplus installed capacity exists, there are several reasons why these resources might not always be available and deployable through the day-ahead and intra-day bilateral energy markets.[6]

First, in jurisdictions outside of the RTO, there is no framework for ensuring that surplus installed capacity is made available in the short-term energy markets. There is no centralized maintenance planning or coordination, no centralized unit commitment process, and no must-offer requirement. Accordingly, entities with surplus installed capacity may nevertheless not have surplus energy available to sell on a short-term basis on a particular day if units are undergoing scheduled maintenance, or if fuel was not purchased to operate a unit, or as a result of other operational or environmental constraints. In short, many resources will only be available on a day-ahead or day-or basis if they are *planned* to be available; currently there is no framework to coordinate that planning in a manner that ensures supply is available in the short-term energy markets.

Second, entities that anticipate having surplus capacity on an annual or seasonal basis can be expected to sell that capacity in the forward markets, instead of reserving it for the spot markets. This is because physical sales in the forward markets—as monthly, quarterly, yearly or multi-year forward commitments—provide resource adequacy benefits to the purchaser and hence can often present a more attractive opportunity to the seller than the short term market. In addition, forward sales of surplus capacity provide sellers with greater certainty regarding the revenues that they will receive than reserving their capacity for the spot market. As a result, it cannot be expected that entities with surplus capacity throughout either the summer and/or winter months will forego

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[6] Moreover, supply assessments may include variable energy resources based on the average forecast output during peak periods, as opposed to the output that has a high confidence of being achieved. Even a very large quantity of installed wind generation is of limited value in meeting peak demand if the wind is not actually blowing during the hours of greatest demand.

forward commitments for that capacity in order to make it available in the short term markets.

Third, entities outside the regional market are unlikely to make capital investments in capacity resources that are in excess of their own forecast peak needs (including an appropriate reserve margin). Because short-term energy market revenues typically are well below the levels necessary to cover the fixed capital costs of many *existing* facilities or investment in new facilities, the potential to make additional spot energy sales during a small number of high-demand days will likely offer only a weak incentive for external entities to take affirmative steps to ensure surplus capacity is available for short-term transactions, and this incentive is all but certain to be insufficient to promote capital investment in resources.

Actual market experience and information corroborates the above concerns. Specifically, historic price index data strongly indicates that there was indeed limited supply available in the short term markets on several of the highest summer and winter load days in the US WECC in recent years. For example, the following table shows prices and calculated "market heat rates" on several high load days in the US WECC over the past 5 years:

Date	DA Mid-C Peak Index	Mid-C Heat Rate (Sumas)	DA PV Peak Index	PV Heat Rate (San Juan)	SP-15 CAISO Peak LMP	SP-15 Heat Rate (SoCal)
8/16/2012	$84.16	31.8	$59.75	30.6	$51.39	17.0
7/2/2013	$120.03	35.9	$119.81	34.8	$81.87	21.4
12/5/2013	$84.36	18.8	$46.29	20.3	$55.77	13.3
2/7/2014	$196.98	24.1	$107.38	25.2	$90.69	12.4
6/26/2015	$68.12	30.0	$37.35	25.3	$45.64	15.5
6/30/2015	$54.55	24.0	$41.73	19.6	$52.85	17.3
7/1/2015	$95.41	37.6	$60.77	34.4	$65.73	21.8
7/2/2015	$79.68	31.4	$59.57	29.1	$48.20	15.8
7/28/2016	$76.76	32.6	$70.93	28.6	$60.88	18.5
7/29/2016	$76.76	34.4	$70.93	29.0	$60.28	19.4

Source: ICE, CAISO OASIS

The above index price data and calculated heat rates represent spot market prices well in excess of the variable operating costs associated with even a relatively inefficient fossil fuel generator. A high market heat rate during peak demand periods strongly suggests that the short-term market was approaching a capacity-related limit on the resources available to supply additional energy on those days. This data also indicates that those entities in the west that have been "going short" on forward capacity commitments and relying on short-term market purchases to meet their peak demand may already be fully consuming any surplus capacity made available in the short-term markets in the region. ***This data strongly suggests that it is unlikely that the region could support up to a***

five-fold increase in the volume of short-term market purchases if California LSEs also begin to rely on such purchases to meet their needs on critical days.

2. "Diversity" In Peak Demand Cannot Be Safely Relied Upon To Avoid Forward Commitment Of Resources

It has also been suggested in this stakeholder process that substantial additional energy can be expected to be available in the short-term markets as a result of diversity in peak loads across entities in the region. Powerex's review of public load data indicates such peak load diversity may be quite limited, since widespread weather events can affect load across the entire region on the same day.

An examination of FERC Form 714 filings permits an analysis of peak load diversity across the US WECC. If US WECC-wide summer and winter peak demand days tend to occur on days that most BAAs were also at (or close to) their own seasonal peak demand days, this would indicate that there is a low amount of peak load diversity. Conversely, it US WECC-wide summer and winter peak demand days tend to occur on days that many BAAs were well below their own seasonal peak demand days, it would indicate that there is a high amount of peak load diversity.

Powerex believes examining the diversity *within* the summer and winter peaking seasons is appropriate for determining the level of short-term capacity that may be available as a result of peak load diversity for several reasons. First, most—if not all—entities in the US WECC experience their peak load events in either the summer or winter seasons, with significantly lower peak loads in the spring and fall seasons. Second, entities that experience their annual peak load in the summer season, such as CAISO, often have significant planned maintenance outages in the winter. Summer-peaking entities may therefore experience tightness in available online supply in both the season with peak load (*i.e.,* summer) as well as the season with lower load but greater planned outages (*i.e.,* winter). Similarly, entities that experience their annual peak load in the winter season typically have significantly higher planned maintenance in the summer season and hence can also experience scarcity conditions in both the winter and summer seasons. Third, an entity that anticipates having surplus capacity during all days of either the summer or winter season can generally be expected to sell such surplus in the forward markets. For example, it is not uncommon for winter-peaking entities in the Northwest to commit their summer surplus capacity to serve loads in summer-peaking BAAs, including CAISO. Any such forward commitments necessarily reduce the surplus capacity remaining available to make shorter-term (*e.g.,* day-ahead or day-of) sales. In other words, *seasonal diversity* creates the ability to take planned maintenance outages in the "off season" as well as to make additional quarterly and monthly forwards sales, which already occurs to a significant degree. But seasonal diversity cannot be presumed to result in significant capacity being available in the short-term day-ahead or day-of markets, since a persistent projected capacity surplus would often be committed on a longer-term basis. Finally, as presented in more detail in the previous section, historic price index data across the US WECC indeed shows that short-term energy price spikes can and do occur in both the summer and winter seasons.

Powerex has thus examined this data separately for the summer and winter periods, ignoring the spring and fall seasons.

The tables below show FERC Form 714 data for two dates:

- June 30, 2015: the US WECC peak day from the most recent summer season (June – September 2015); and

- December 30, 2014: the US WECC peak day from the most recent winter seasons (November 2014 – February 2015).

In the tables below, the difference (in MW) between each reporting entity's highest demand on the specified day and its seasonal peak demand is noted, as an indication of possible short-term surplus capacity on the specified day (assuming each entity had sufficient capacity on its own to meet its seasonal peak demand).

Peak Hourly Load by Reporting Entity during Highest Load Day of Summer 15
Tuesday, June 30, 2015

Entity	Peak Load	% of Reported Load in WECC	% of Seasonal Peak	MW below Seasonal Peak
California Independent System Operator	41,892	31%	88.7%	5,363
PacifiCorp (East & West combined)	12,578	9%	99.6%	56
Bonneville Power Administration	7,635	6%	98.3%	134
Public Service Company of Colorado	7,721	6%	96.8%	254
Arizona Public Service Company	6,448	5%	88.1%	872
Salt River Project	6,012	4%	87.2%	883
Los Angeles Department of Water and Power	5,442	4%	79.2%	1,430
Nevada Power Company	6,069	4%	100.0%	0
Puget Sound Energy, Inc.	3,419	3%	97.5%	86
Western Area Power Administration - Colorado-Missouri	3,901	3%	97.0%	122
Portland General Electric Company	3,658	3%	92.4%	300
Idaho Power Company	3,766	3%	100.0%	0
Sacramento Municipal Utility District (& City of Redding Electric Utility)	2,936	2%	99.3%	20
Tucson Electric Power Company	2,746	2%	87.6%	388
Tri-State G & T Assn., Inc.	2,406	2%	98.0%	50
Avista Corporation	2,070	2%	98.8%	25
Sierra Pacific Resources	2,097	2%	100.0%	0
Western Area Power Administration - Lower Colorado	1,211	1%	85.2%	211
Seattle City Light	1,335	1%	99.0%	13
Public Service Company of New Mexico	1,794	1%	91.4%	169
NorthWestern Energy	1,729	1%	96.6%	61
El Paso Electric Company	1,532	1%	85.4%	262
Basin Electric Power Cooperative	322	0%	95.0%	17
City of Tacoma, Dept. of Public Utilities	618	0%	95.4%	30
Imperial Irrigation District	831	1%	83.8%	161
Colorado Springs Utilities	820	1%	96.4%	31
PUD No. 2 of Grant County	789	1%	98.6%	11
PUD No. 1 of Chelan County	513	0%	99.2%	4
Modesto Irrigation District	625	0%	95.9%	27
Turlock Irrigation District	608	0%	98.9%	7
Platte River Power Authority	588	0%	92.0%	51
Black Hills Corporation	581	0%	91.5%	54
Eugene Water & Electric Board	355	0%	93.9%	23
PUD No. 1 of Douglas County	0	0%		
Arizona Electric Power Cooperative, Inc.	57	0%	93.4%	4
City of Burbank	251	0%	82.0%	55
Metropolitan Water District of Southern California	290	0%	97.6%	7
Western Area Power Administration - Upper Missouri West	163	0%	98.8%	2
				11,183

Note: Excludes data submitted by San Diego to avoid double-counting load within CAISO

Peak Hourly Load by Reporting Entity during Highest Load Day of Winter 2014/2015
Tuesday, December 30, 2014

Entity	Peak Load	% of Reported Load in WECC	% of Seasonal Peak	MW below Seasonal Peak
California Independent System Operator	30,873	29%	98.5%	478
PacifiCorp - (East & West combined)	8,870	8%	89.4%	1,054
Bonneville Power Administration	9,277	9%	98.2%	170
Public Service Company of Colorado	6,539	6%	100.0%	0
Arizona Public Service Company	4,097	4%	93.3%	294
Salt River Project	3,748	3%	92.7%	297
Los Angeles Department of Water and Power	3,530	3%	90.8%	356
Nevada Power Company	2,968	3%	98.4%	47
Puget Sound Energy, Inc.	4,372	4%	96.2%	172
Western Area Power Administration - Colorado-Missouri	3,796	4%	100.0%	0
Portland General Electric Company	3,541	3%	100.0%	0
Idaho Power Company	2,407	2%	96.6%	86
Sacramento Municipal Utility District (& City of Redding Electric Utility)	1,567	1%	99.8%	3
Tucson Electric Power Company	1,869	2%	89.0%	230
Tri-State G & T Assn., Inc.	2,248	2%	100.0%	0
Avista Corporation	2,162	2%	100.0%	0
Sierra Pacific Resources	1,729	2%	100.0%	0
Western Area Power Administration - Lower Colorado	1,247	1%	93.5%	87
Seattle City Light	1,635	2%	91.4%	153
Public Service Company of New Mexico	1,564	1%	100.0%	0
NorthWestern Energy	1,735	2%	100.0%	0
El Paso Electric Company	1,057	1%	94.2%	65
Basin Electric Power Cooperative	441	0%	96.1%	18
City of Tacoma, Dept. of Public Utilities	875	1%	93.6%	60
Imperial Irrigation District	392	0%	89.5%	46
Colorado Springs Utilities	770	1%	100.0%	0
PUD No. 2 of Grant County	613	1%	92.6%	49
PUD No. 1 of Chelan County	647	1%	95.4%	31
Modesto Irrigation District	303	0%	90.4%	32
Turlock Irrigation District	306	0%	95.6%	14
Platte River Power Authority	509	0%	99.6%	2
Black Hills Corporation	584	1%	100.0%	0
Eugene Water & Electric Board	430	0%	92.8%	33
PUD No. 1 of Douglas County	322	0%	91.0%	32
Arizona Electric Power Cooperative, Inc.	33	0%	94.3%	2
City of Burbank	141	0%	81.0%	33
Metropolitan Water District of Southern California	300	0%	100.0%	0
Western Area Power Administration - Upper Missouri West	158	0%	98.8%	2
				3,846

Note: Excludes data submitted by San Diego to avoid double-counting load within CAISO

From the tables above, it appears that there existed substantial diversity in peak loads during the summer season of 2015, but there was substantially less diversity in peak loads experienced during the winter season of 2014/2015.

From the perspective of ensuring reliability, it is also important to look beyond the most recent results in to order gauge whether peak load diversity can be relied upon to exist with a high degree of certainty. An examination of the last decade of winter and summer seasons illustrates that indeed, in some years, west-wide weather events occur, and loads in most BAAs reach (or come very close to) their seasonal peak levels on the very same day. On such days, there is little or no peak load diversity. Powerex has more closely examined two such days:

- July 24, 2006: the highest WECC summer peak day in the past 10 years; and
- December 9, 2013: one of the highest WECC winter peak days in the past 10 years.

Peak Hourly Load by Reporting Entity during Highest Load Day of Winter 2013/2014
Monday, December 09, 2013

Entity	Peak Load	% of WECC Load	% of Seasonal Peak	MW below Seasonal Peak
California Independent System Operator	33,446	30%	100.0%	0
PacifiCorp -(East & West combined)	9,451	9%	100.0%	0
Bonneville Power Administration	10,627	10%	99.8%	16
Public Service Company of Colorado	6,298	6%	99.9%	4
Arizona Public Service Company	4,251	4%	100.0%	0
Salt River Project	3,795	3%	100.0%	0
Los Angeles Department of Water and Power	3,798	3%	97.6%	94
Nevada Power Company	3,146	3%	100.0%	0
Puget Sound Energy, Inc.	4,810	4%	98.2%	86
Portland General Electric Company	3,900	4%	100.0%	0
Idaho Power Company	2,756	2%	100.0%	0
Sacramento Municipal Utility District (& City of Redding Electric Utility)	1,734	2%	100.0%	0
Tucson Electric Power Company	1,968	2%	100.0%	0
Tri-State G & T Assn., Inc.	2,128	2%	100.0%	0
Avista Corporation	2,216	2%	93.1%	164
Sierra Pacific Resources	1,776	2%	100.0%	0
Western Area Power Administration - Lower Colorado	1,181	1%	82.3%	254
Seattle City Light	1,840	2%	98.7%	25
Public Service Company of New Mexico	1,600	1%	100.0%	0
NorthWestern Energy	1,699	2%	97.6%	41
El Paso Electric Company	1,109	1%	99.0%	11
Basin Electric Power Cooperative	418	0%	94.4%	25
City of Tacoma, Dept. of Public Utilities	980	1%	96.5%	36
Imperial Irrigation District	413	0%	91.8%	37
Colorado Springs Utilities	758	1%	97.2%	22
PUD No. 2 of Grant County	653	1%	94.5%	38
PUD No. 1 of Chelan County	698	1%	95.9%	30
Modesto Irrigation District	355	0%	100.0%	0
Turlock Irrigation District	336	0%	100.0%	0
Platte River Power Authority	505	0%	98.8%	6
Black Hills Corporation	570	1%	96.6%	20
Eugene Water & Electric Board	557	1%	100.0%	0
PUD No. 1 of Douglas County	358	0%	91.3%	34
Arizona Electric Power Cooperative, Inc.	37	0%	100.0%	0
City of Burbank	161	0%	90.4%	17
Metropolitan Water District of Southern California	264	0%	100.0%	0
Western Area Power Administration - Upper Missouri West	141	0%	83.4%	28
				988

Note: Excludes data submitted by San Diego to avoid double-counting load within CAISO. In addition, data submitted by Western Area Power Administration - Colorado-Missouri was excluded due to a data error.

Peak Hourly Load by Reporting Entity in Highest Load Day of Summer 2006
Monday, July 24, 2006

Entity	Peak Load	% of WECC Load	% of Seasonal Peak	MW below Seasonal Peak
California Independent System Operator	50,085	37%	100.0%	0
PacifiCorp -(East & West combined)	9,322	7%	100.0%	0
Bonneville Power Administration	7,544	6%	100.0%	0
Arizona Public Service Company	7,445	5%	96.5%	267
Salt River Project	6,625	5%	97.9%	145
Los Angeles Department of Water and Power	6,102	4%	100.0%	0
Nevada Power Company	5,905	4%	98.1%	117
Puget Sound Energy, Inc.	3,453	3%	100.0%	0
Western Area Power Administration - Colorado-Missouri	3,321	2%	100.0%	0
Portland General Electric Company	3,746	3%	100.0%	0
Idaho Power Company	3,359	2%	100.0%	0
Sacramento Municipal Utility District (& City of Redding Electric Utility)	3,280	2%	100.0%	0
Tucson Electric Power Company	2,548	2%	98.2%	46
Tri-State G & T Assn., Inc.	2,137	2%	99.7%	6
Avista Corporation	2,021	1%	100.0%	0
Sierra Pacific Resources	2,019	1%	100.0%	0
Western Area Power Administration - Lower Colorado	1,978	1%	90.2%	216
Seattle City Light	1,427	1%	100.0%	0
Public Service Company of New Mexico	1,806	1%	97.4%	49
NorthWestern Energy	1,599	1%	97.3%	45
El Paso Electric Company	1,433	1%	99.1%	13
Basin Electric Power Cooperative	1,338	1%	87.6%	189
City of Tacoma, Dept. of Public Utilities	634	0%	100.0%	0
Imperial Irrigation District	939	1%	94.6%	54
Colorado Springs Utilities	824	1%	100.0%	0
PUD No. 2 of Grant County	559	0%	96.5%	20
PUD No. 1 of Chelan County	397	0%	97.8%	9
Modesto Irrigation District	695	1%	98.3%	12
Turlock Irrigation District	614	0%	100.0%	0
Platte River Power Authority	586	0%	97.2%	17
Black Hills Corporation	392	0%	94.5%	23
Eugene Water & Electric Board	423	0%	100.0%	0
PUD No. 1 of Douglas County	213	0%	99.1%	2
Arizona Electric Power Cooperative, Inc.	357	0%	98.9%	4
City of Burbank	307	0%	100.0%	0
Metropolitan Water District of Southern California	222	0%	100.0%	0
Western Area Power Administration - Upper Missouri West	121	0%	94.5%	7
				1,241

Note: Excludes data submitted by San Diego and Pacific Gas & Electric to avoid double-counting load within CAISO.

This analysis indicates that west-wide heat waves and/or west-wide cold snaps can and do occur. When these region-wide events occur, most entities experience peak loads that are at, or very near, their seasonal peak levels. On the days examined above, the total reported peak load was within approximately 1,000 MW of the sum of the individual seasonal peaks for each reporting entity. This shows that, while any given year *might* show diversity in peak demand within the summer and winter seasons, there can also be widespread events that result in a large number of regional entities experiencing their seasonal peak needs on the same day, and therefore result in little or no peak load diversity.

3. LSEs Will Have A Financial Incentive To Underinvest In Forward RA Procurement

While the data discussed above indicates that the western bilateral short-term energy markets should not be broadly relied upon to address shortfalls from LSEs that elect to "go short" on the capacity necessary to meet RA requirements, especially under peak conditions, this might not pose a reliability concern if LSEs could be expected to reduce their spot market reliance, either voluntarily or in response to penalties or other sanctions. However, there are several reasons why LSEs will have a strong incentive to rely on spot market purchases to the maximum extent permitted by the Draft Proposal.

First, there is a financial incentive to simply reduce costs. Because average short-run energy prices are chronically below the levels needed to maintain existing resources and support the development of new resources, it will nearly always cost less to buy energy in the spot market than to make forward commitments in order to secure resources in advance.

Second, the integrated nature of a regional organized market means that the reliability impacts of one LSE's forward procurement decisions are socialized over all users of the grid. Supply adequacy affects the quality of service to all consumers throughout a BAA, and is not limited only to customers of an individual LSE within the BAA. So while 100% of the cost savings associated with relying on short-term purchases will flow to the individual LSE taking that approach, the reliability consequences can be expected to be spread across all of the LSEs in the BAA. Conversely, an individual LSE will not reap the full reliability improvements from securing resources in advance, since it will remain exposed to the consequences of under-procurement by other LSEs within the BAA.

Given the potential cost savings and the fact that LSEs would only realize a fraction of the reliability consequences of taking this approach, one should expect all LSEs to take full advantage of the ability under the Draft Proposal to rely on spot energy purchases for up to 10% of their RA requirement.

Powerex also believes that it is unlikely that assessing penalties on LSEs could mitigate the reliability risks of its proposal. In particular, it is unlikely that any financial penalty imposed by CAISO would be sufficiently high that an LSE would prefer investing in maintaining or developing capacity over relying on short-term purchases. Because penalties would only be applied during system emergencies or other extreme events, which arise infrequently, the financial penalty would need to be implausibly high for a BA to rationally choose to invest in sufficient forward capacity to meet these events rather than simply incurring an infrequent penalty.

The infeasibility of adopting a financial penalty capable of deterring reliance on spot-market purchases is illustrated by a simple example. Suppose, for example, that an LSE is confident that meeting 90% of its RA requirement with the forward procurement of capacity is sufficient to meet load during all but 10 hours of the year. It could either: (1) procure additional capacity at $50/kW-year; or (2) it could simply risk relying on the spot energy market to meet the remaining 10% of its RA requirement, accepting the possibility that it will be required to pay a penalty in up to 10 hours during the year. In this case, it would require a penalty of at least $5,000 per MW of any shortfall to provide a financial incentive for the LSE to procure forward capacity to meet 100% of its RA requirement.[7]

For that reason, the most likely outcome of an after-the-fact penalty would be to encourage LSEs to make best efforts to procure the energy required to meet its RA obligations in the short-term markets, including when stressed system conditions arose (as opposed to not meeting the RA requirement at all). At that point in time, however, it may be too late to acquire such supply, since insufficient capacity may be committed to be available for sale in short-term markets.

B. Relying On Spot Energy Purchases For Reliability Is Not The Practice Of "Many Entities in the West"

The Draft Proposal states that "many entities … maintain resource adequacy while relying on some short-term arrangements[.]"[8] Powerex analyzed publicly available data from FERC's electric quarterly reports ("EQR") to examine short-term net purchases by entities in the west during times of peak system conditions.

The figures below show, for each entity, the total EQR reported quantity of daily and hourly purchases, net of sales, over the peak load hours on three specific dates.[9] For presentation purposes, the top 10 net purchasers are shown. The figures correspond to three of the four dates identified in the prior analysis of peak load diversity. The fourth date previously identified—July 24, 2006—was not analyzed due to incomplete EQR information during this period.[10]

These three specific dates analyzed are:

- June 30, 2015: The most recent WECC-wide summer (June – September) peak day;

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[7] In reality, the penalty may need to be substantially higher to reflect the LSE's expectations of the likelihood that it will be able to procure surplus energy through short-term purchases. For example, if the LSE believes that it will be able to procure energy to meet system needs in 5 of the 10 hours, the financial penalty would need to be $10,000 per MW.

[8] Draft Proposal at 42.

[9] The analysis of EQR data involves retrieving and compiling the EQRs of all reporting entities, and totaling sales reported to each identified purchaser. The analysis is therefore limited by the accuracy of EQR submissions, the completeness of the EQR datasets provided by FERC, and how the individual data fields were compiled.

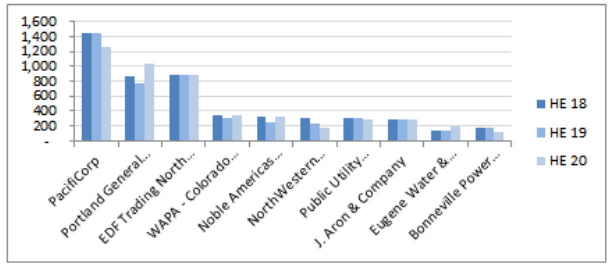
[10] FERC Order 768 required non-public utilities to begin filing quarterly EQR reports as of Q3 2013. Prior to that date, information on sales by non-public utilities may be incomplete.

- December 30, 2014: The most recent WECC-wide winter (November – February) peak day; and

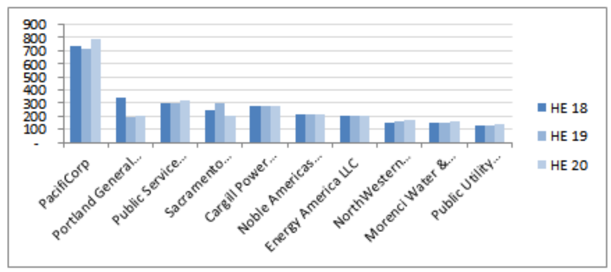
- December 9, 2013: One of the highest WECC winter peak of the past 10 years.

Short Term (Daily and Hourly) Net Purchases during Peak Hours, excluding CAISO

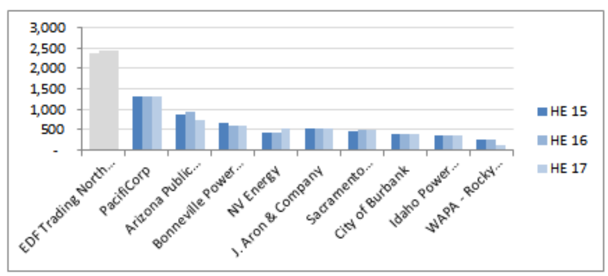
Monday, December 09, 2013	HE 18	HE 19	HE 20
PacifiCorp	**1,438**	**1,438**	**1,258**
Portland General Electric	866	766	1,031
EDF Trading North America LLC	879	880	875
WAPA - Colorado River Storage Project	353	306	351
Noble Americas Energy Solutions LLC	316	244	316
NorthWestern Corporation	314	239	168
Public Utility District No. 1 of Clark County	307	307	287
J. Aron & Company	295	295	291
Eugene Water & Electric Board	140	137	202
Bonneville Power Administration	179	179	123



Tuesday, December 30, 2014	HE 18	HE 19	HE 20
PacifiCorp	**736**	**711**	**786**
Portland General Electric	339	188	203
Public Service Company of Colorado	294	294	319
Sacramento Municipal Utility District	249	299	199
Cargill Power Markets LLC	282	282	282
Noble Americas Energy Solutions LLC	219	219	219
Energy America LLC	208	208	208
NorthWestern Corporation	155	160	175
Morenci Water & Electric	150	154	158
Public Utility District No. 1 of Clark County	125	125	142



Tuesday, June 30, 2015	HE 15	HE 16	HE 17
EDF Trading North America LLC (see note)	*2,367*	*2,435*	*2,435*
PacifiCorp	**1,309**	**1,307**	**1,325**
Arizona Public Service Company	852	933	733
Bonneville Power Administration	656	606	606
NV Energy	426	426	526
J. Aron & Company	525	525	525
Sacramento Municipal Utility District	466	486	486
City of Burbank	375	375	375
Idaho Power Company	367	367	367
WAPA - Rocky Mountain Region	245	255	127

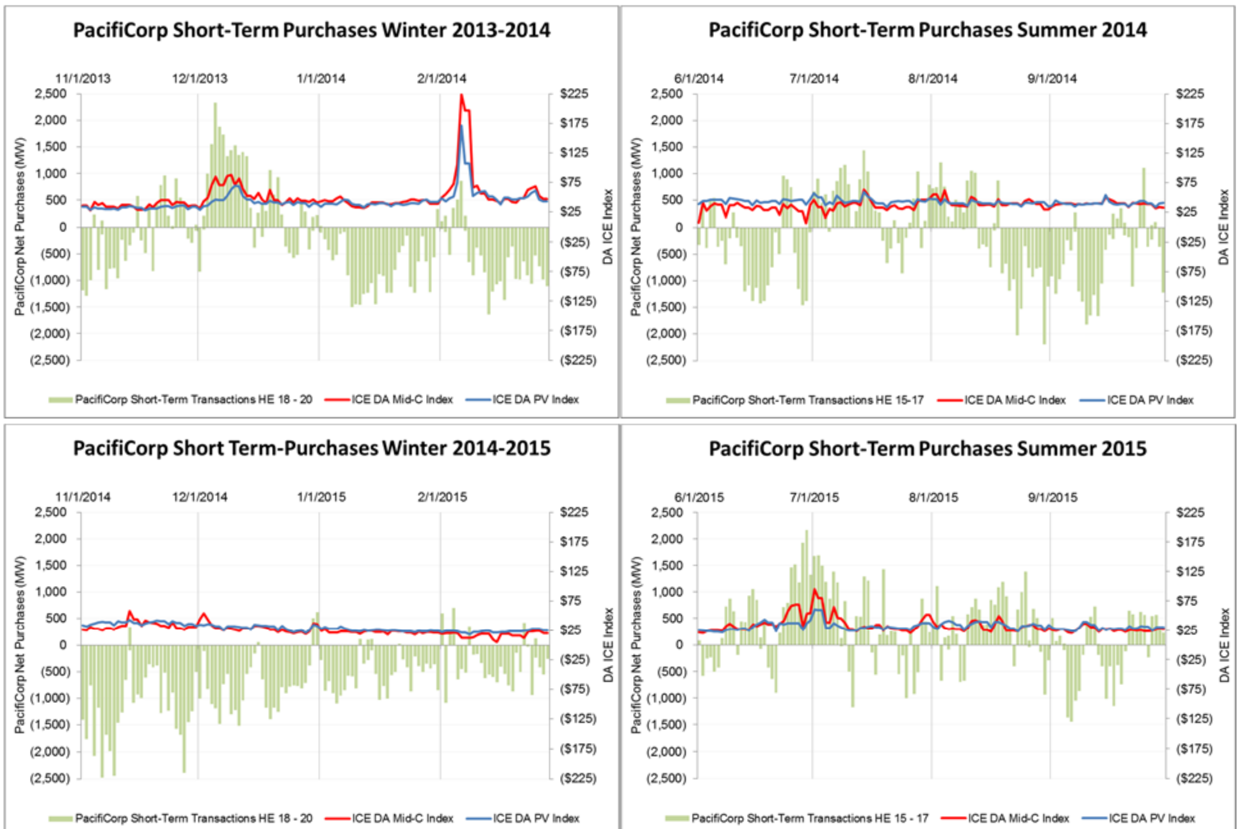


Source: FERC EQR

Note: large net purchases by EDF on June 30 appear to reflect incomplete information: all of EDF's short-term sales were omitted from the FERC EQR on this date, while purchases were reported.

From Powerex's examination of these summer and winter days of highest west-wide demand, there appear to be very few entities across the entire region— other than PacifiCorp—that regularly purchased large quantities of short-term energy. Powerex encourages CAISO to compile and present any data it believes demonstrates that it is a widespread regional practice for load-serving entities to rely on significant quantities of short-term energy purchases to meet peak demand needs.

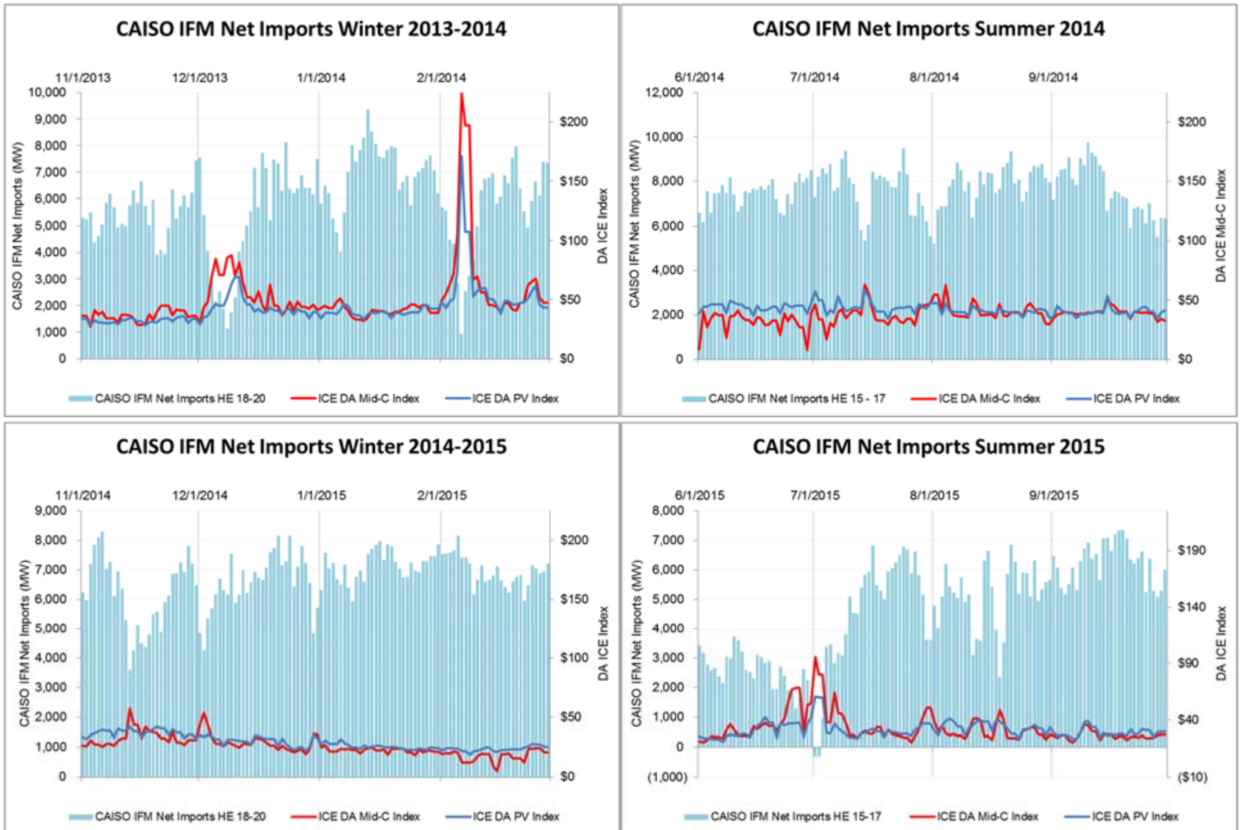
One might argue that purchases, even during peak demand days, do not necessarily indicate that the purchaser *lacked* its own sufficient resources to meet its needs; it could simply indicate that the purchaser's resources were more expensive than the purchased energy. However, publicly available pricing data shows that PacifiCorp's net purchases generally coincide with high bilateral index prices—the exact opposite of what would generally be observed for entities pursuing economic displacement opportunities (*e.g.,* displacing use of high-cost generation with lower-cost short-term purchases, and/or buying low and selling high). The charts below, also based upon EQR data, show PacifiCorp's short-term net purchase activity during the highest load hours over the duration of the applicable season, including the peak days identified previously but also the entire seasonal period before and after that day. The daily ICE index price for Mid-Columbia and Palo Verde on-peak energy is also shown.



Sources: FERC EQR, ICE

The EQR data shows that PacifiCorp often purchased short-term energy when prices were relatively *high*, consistent with an entity that has chosen to rely on spot energy purchases—even at high prices—to make up for a lack of resources committed on a forward basis.

This stands in contrast to the transactions for an entity with a robust resource adequacy framework, such as the CAISO. The figures below show the net imports into the CAISO BAA during the same hours over the same four seasons.



Sources: CAISO OASIS, ICE

The CAISO activity appears consistent with economic displacement transactions: as energy supplies from outside of the CAISO become more expensive, the imports into the CAISO BAA decline. This data for CAISO is thus consistent with an entity that has a robust resource adequacy framework, and utilizes the short-term energy markets to achieve the most economically efficient use of resources.

In short, publicly available data indicates that PacifiCorp systematically relies on a substantial quantity of short-term energy market purchases to meet its peak demand needs and ***is one of the only entities to employ this approach to resource planning in the region***. Thus, it is not clear that a core tenet of the CAISO/CPUC RA framework—to require forward contracting for the full amount of the RA requirement—needs to be altered in order to accommodate the resource planning practices of most entities in the west. Instead, this data indicates that it is PacifiCorp—and perhaps only PacifiCorp—that currently has a resource planning approach that may be significantly out of step with the CAISO's robust resource adequacy framework.

III. Any Changes To The Forward RA Requirement Should Be Carefully Considered

Powerex believes that additional steps are needed to evaluate any proposal to lower the forward RA contracting requirements. As an initial matter, stakeholders would greatly benefit from CAISO conducting an objective analysis of the reliability and economic impacts of lowering the forward contracting requirement. In addition, in the event that CAISO and stakeholders elect to proceed with efforts to reduce the forward RA requirement after reviewing the results of this analysis, Powerex believes that the forward contracting requirement should be modified in a direct and transparent manner, by reducing the planning reserve margin that defines the RA requirements for LSEs, thus permitting CAISO to conduct all spot energy market procurement activity.

A. Further Analysis Is Required

Powerex believes that the evidence above raises significant questions regarding the Draft Proposal's potential to adversely affect reliability in an expanded RTO footprint. Before moving forward with such a significant change in resource adequacy policy, Powerex believes supporting evidence and analysis must be supplied to enable stakeholders and the CPUC to meaningfully evaluate the full range of potential economic and reliability implications of the Draft Proposal. Powerex believes it is simply not enough to note that PacifiCorp has generally been able to rely upon some quantity of short-term energy purchases so far to keep the lights on during peak periods. The issue is whether such an approach can—or should—be expanded and applied across a much larger, multi-state RTO and, if so, what are the appropriate limits on that approach.

For that reason, before moving forward with the Draft Proposal, Powerex believes that CAISO should present an analysis of the potential economic and reliability implications of its proposal and make the data underlying that analysis available to stakeholders and the CPUC. Specifically, such an analysis might comprise of at least the following elements:

- A comprehensive review of the extent to which entities in the west include spot market energy purchases in their forward resource plans;
- Expected physical supplies available in the spot energy markets from entities outside of the RTO footprint on peak demand days, and a discussion of the basis for those expectations;
- Capital investment savings to regional market LSEs from reduced forward contracting requirement compared to proposed penalties; and
- The expected impact of the Draft Proposal on the "missing money" problem and on incentives for resource retirement and new resource development.

B. Any Reduction In The Forward RA Requirement Should Be Done In A More Transparent And Efficient Manner

In the event that CAISO and stakeholder conclude that reducing the forward RA requirement is prudent after reviewing the results of CAISO's analysis, Powerex believes that it would be more transparent and efficient to simply lower the RA requirement explicitly. CAISO's current proposal reduces the forward RA requirement indirectly by permitting a portion of the RA requirement to not be met through forward contracts. A more direct and transparent way of achieving the same result would be to re-define the RA requirement from being equal to 115% of peak load to being equal to just 103.5% of peak load. Under this alternative, each LSE would continue to be required to procure 100% of its (reduced) RA requirement by the deadline for the monthly showing.

Powerex believes that formally lowering the requirement will avoid duplicating and fragmenting the short-term procurement of energy between LSEs and the CAISO. Under the Draft Proposal, both the CAISO and individual LSEs would be engaging in short-term market transactions to purchase and schedule energy on the RTO's external interties. In particular, CAISO would continue to accept bids and offers at the interties, just as it does today, while LSEs that rely on short-term energy purchases for RA will also be procuring energy on those same interties, and often in the very same time period. In practice, CAISO and LSEs will be procuring energy from the same ultimate external sources of energy. It is unclear what benefit, if any, would be achieved by having a regional market in which both the CAISO and individual member LSEs both engage in short-term procurement of energy. To the contrary, it is highly likely that CAISO's organized market will be more efficient in procuring energy than the individual and fragmented efforts of LSEs.

In addition, allowing LSEs to procure energy in the bilateral short-term markets to satisfy RA requirements could reduce the flexibility of intertie participation in the organized markets. This is because bilateral energy transactions generally do not convey dispatch capabilities to the purchaser. For instance, if PacifiCorp purchases on-peak, day-ahead energy to satisfy its RA requirement, the transaction will typically require physical delivery of the contract quantity in each of the 16 hours comprising the standard on-peak product. In contrast, import offers that clear in CAISO's day-ahead or real-time markets can vary in quantity in each hour, and the hours of delivery need not conform to any multi-hour product definition. Thus, external energy procured by CAISO through its markets may provide considerably more flexibility than bilateral procurement by LSEs, which are likely to be delivered as multi-hour self-scheduled blocks.

In short, Powerex believes it would be inefficient and imprudent to implement a regional RA framework that leads to duplicative and fragmented procurement of day-ahead energy between entities within a multi-state RTO and physical resources located outside of it. If CAISO and stakeholders ultimately conclude that forward RA requirements should be reduced, then it should be done in a manner that allows CAISO to engage in short-term energy market procurement on behalf of the RTO.