CAISO DAM Enhancements: Efficient Day-Ahead Dispatch, Pricing And Settlement Of Energy, Capacity, And Ancillary Services

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DRAFT

Executive Summary

CAISO is currently exploring substantive enhancements to its existing Day-Ahead Market ("DAM") design in a stakeholder process that has been underway since the summer of 2018. The DAM Enhancements stakeholder process is exploring extensive changes to the design of the existing CAISO DAM, including adding a day-ahead Flexible Ramping Product and combining CAISO's residual unit commitment process with its day-ahead energy and ancillary services market optimization process. While Powerex believes there is the potential for significant benefits from such an approach, Powerex also notes that CAISO anticipates commencing a stakeholder process in 2019 to explore the potential expansion of its DAM, on a voluntary basis, to regions in the Western Interconnection outside of the CAISO Balancing Authority Area ("BAA"). The stakeholder dialogue surrounding such an Extended Day-Ahead Market ("EDAM") is expected to include, among other critical topics, a detailed examination of what products will be transacted through the organized market, what the requirements will be for suppliers and purchasers, and how prices will be determined.

In light of the above, Powerex believes that major changes to the design of the CAISO DAM are best considered in the context of developing a proposal that could be workable for an EDAM. Market design changes developed and approved in the specific context of a California-focused stakeholder initiative may ultimately be poorly suited to being applied to an EDAM that extends beyond California, and therefore may be eclipsed by further regional discussions or may inadvertently weaken support for an EDAM.

The design of a potential EDAM proposal, and the process through which that design is determined, will be paramount to building broad regional support for such an organized market. If an EDAM emerges and grows to include a large number of entities in the region, it can be expected to replace a material fraction of transactions that currently occur through day-ahead bilateral trading, and also influence the value of bilateral transactions that continue to occur. The design of an EDAM will therefore have significant implications beyond the formal EDAM footprint. Consequently, it is important for all regional stakeholders—even those that do not currently anticipate exploring participation in a potential EDAM—to actively engage in stakeholder processes regarding the design of organized markets as they expand in the region.

One particular area that merits careful consideration in the DAM Enhancements stakeholder process is the supply delivery obligations and price formation approaches that may be required under a broader regional DAM. Importantly, there is currently a major misalignment between the supply performance requirements and price formation approaches of current organized markets, including the CAISO DAM, and those that prevail under the day-ahead bilateral market framework that exists outside of the CAISO BAA. Whereas bilateral transactions generally occur under standardized products for "firm energy"—in which the seller is required to have the physical capacity to be able to deliver the contracted energy—the current CAISO DAM is an "energy only" market design, relying only on financial incentives to encourage delivery on day-ahead market awards. The transaction prices in bilateral markets reflect the different quality of the products traded therein. In bilateral markets, transaction prices reflect both the energy as well as the hourly and/or daily capacity attributes that are bundled into the "firm energy" product. In contrast, the current CAISO DAM, similar to other organized markets, pays an "energy only" price that does not differentiate between firm supply, virtual supply, and any spectrum of products in between.

The "energy only" nature of the current CAISO DAM design does not mean, however, that the CAISO does not procure physical capacity on a day-ahead basis. It just means that hourly and/or multi-hour backstop and/or residual capacity may be procured outside of the organized market for energy, and outside of the price formation process that determines compensation for the majority of supply. In other words, while CAISO may procure and compensate hourly and/or multi-hour physical capacity in order to "backstop" the subset of day-ahead energy supply that might not perform, it does not provide any implicit or explicit capacity compensation to day-ahead supply that is already "firm," that is counted on to deliver with a high degree of confidence, and that therefore avoids the need for CAISO to procure additional hourly and/or multi-hour "backstop" capacity.

The separate and sequential procurement of day-ahead energy followed by residual or backstop capacity commitments applied in most organized markets, including the CAISO DAM, has substantive inefficiencies, as it does not consider the potential tradeoffs between scheduling a resource for energy as opposed to preserving "headroom" on the resource in order to provide upward capacity in real-time. Instead, these separate residual or backstop capacity commitment processes are limited to awarding residual capacity commitments only to those resources that happen to have not already been fully scheduled for energy in the DAM.

A combined DAM design that simultaneously optimizes the procurement of energy, ancillary services, and flexible capacity—*and compensates all resources for the capacity and flexible capacity attributes that they provide*—could make significant progress both toward achieving a more efficient day-ahead market solution within the CAISO BAA as well as toward achieving a day-ahead organized market design that is perhaps more likely to be workable for a broad range of entities and regions in the west. This paper explores this concept in greater detail, and includes various appendices with illustrative examples.

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I. Sound Price Formation Is Critical To Enabling A Regional Day-Ahead Organized Market In The West

A. The Importance Of Accurate Short-Term Energy Prices

Average day-ahead and real-time market prices have declined in wholesale electricity markets over the past decade. These price declines are largely a result of changing supply fundamentals, particularly (1) lower variable costs for natural gas generation, arising from the rapidly expanded application of shale gas withdrawal technologies; (2) retirement and replacement of older, less efficient resources with newer, more efficient resources; and (3) rapid and ongoing expansion of Variable Energy Resources ("VERs"), which typically have very low or even negative variable production costs when the relevant natural energy source is available.

Lower wholesale electricity prices have provided undeniable near-term economic benefits to *purchasers.* However, this has also increased challenges for *suppliers* by exacerbating the "missing money" problem. The "missing money" problem refers to the insufficiency of wholesale energy market revenues to support investment in new generation resources when and where they are needed on the grid, or even the revenues required to maintain many existing generation resources that continue to be needed to meet demand and support reliability. The Federal Energy Regulatory Commission ("FERC"), organized market operators and market monitors, as well as numerous industry economists, have repeatedly expressed concerns with the "missing money" problem, since it implies that other sources of revenue are needed in order to maintain the quantity and type of resources in operation to reliably serve demand. The additional revenue streams that have been considered, and in some regions implemented, include centralized capacity markets (primarily in the eastern markets), bilateral contracting to meet Resource Adequacy requirements, or longer-term contracts under the integrated resource plans of load-serving entities. But such mechanisms are a long way removed from the objective of compensating the specific resources that actually provide energy when and where it is needed to reliably serve load. For this reason, FERC and most market design experts have advocated for improving the short-term energy price signals to the greatest extent possible.[1] This dialogue has included consideration of targeted market design enhancements, such as fast-start pricing and improved scarcity pricing, the development of new flexible capacity products, as well as exploration of new organized market price formation approaches with the goal of better supporting efficient wholesale market outcomes, including more efficient short-term energy prices. These efforts highlight the growing need for organized markets to develop new approaches to the dispatch, pricing, and compensation of the capacity and

[1] To the extent more efficient short-term energy prices increase total short-term energy costs, this is generally regarded as beneficial, as it reduces the revenue that needs to be provided through supplemental mechanisms including forward capacity contracts, which are less able to compensate the specific resources that provide energy when and where it is most needed to reliably serve load.

flexible capacity attributes that are increasingly needed to maintain reliable operation of the grid.

B. Day-Ahead Market Design Can Have A Large Impact On Ratepayer Value

In the context of a potential western EDAM, price formation has added importance, as entities, regions, and ratepayers across the west often have diverse, and at times competing, wholesale energy market interests. For example, California ratepayers are large net purchasers of wholesale energy products, both from California's fleet of merchant generators, as well as from suppliers in neighboring regions. Accordingly, California ratepayers may *benefit* substantially, at least in the near-term, from lower wholesale energy market prices, regardless of whether these low prices are achieved solely through efficiency improvements or through price formation practices that inappropriately depress prices. In contrast, ratepayers of northwest hydro utilities are generally large net sellers of wholesale energy products, both to California as well as to other utilities. This is because northwest hydro utilities have already secured, on a longer-term basis, sufficient - and in many cases surplus - energy, capacity, flexibility, and other necessary attributes to reliably serve local demand. Revenues from surplus sales generally lower retail rates for retail customers of these entities. Thus, northwest hydro utilities' ratepayers are generally *harmed* by depressed wholesale energy prices. Even ratepayers of utilities that are relatively "neutral" over the course of a year are still likely to be affected by price formation issues. For instance, investor-owned utilities in both the northwest and the desert southwest are often net sellers of wholesale energy products during the higher priced hours on most days; these ratepayers may generally be *harmed* by price formation practices that depress the value of those sales. This harm may or may not be offset by any benefit these same ratepayers receive from depressed prices during other hours or days in which they are net purchasers of wholesale energy products.

The different circumstances of the various entities and regions leads to divergent—and often competing—interests and priorities for how a market should be designed, and particularly how prices in a market should be determined. These differences are especially acute in the context of the tremendous volume of day-ahead wholesale energy trade in the west, since rules, processes and practices that either inefficiently depress or inefficiently elevate day-ahead prices can be expected to result in tremendous shifts of value between the ratepayers of different entities and regions. These concerns are further heightened by the fact that day-ahead market prices also have great importance to the value of forward energy market transactions, as futures contracts generally settle against day-ahead wholesale energy price indices.

Building broad regional support for a western EDAM in the upcoming EDAM stakeholder process will require carefully balancing the diverse interests of various entities, regions, and their ratepayers. And since many market design decisions are likely to be favorable to some interests but not others, it will be critical that market design choices be guided by industry best practices.

It will thus be important that decisions made in the CAISO DAM Enhancements stakeholder process be made in recognition of the upcoming EDAM stakeholder process, reducing the risk that material changes made now to the CAISO DAM design prove to be unworkable or unacceptable for application to an EDAM.

C. Material Differences Between CAISO's Current Organized Market Design And Existing Western Bilateral Markets Must Be Bridged

There are several key areas in which transactions in the CAISO's DAM differ from transactions in the day-ahead bilateral markets outside the CAISO BAA. It will be critical for stakeholders to examine how each of these differences can affect market efficiency as well as price formation and, ultimately, compensation. Importantly, the pursuit of the efficiency gains afforded by a western day-ahead organized market must not come at the expense of less efficient price formation practices compared to the price outcomes that exist today in western bilateral markets.

This paper focuses primarily on the implications of the "energy only" approach to dispatch, price formation, and settlement that is applied in the CAISO's current DAM.[2] The CAISO's "energy only" approach, combined with its day-ahead RUC process, stands in contrast to the "firm energy" product that is the foundation of day-ahead bilateral markets and price formation outside of the CAISO BAA. There are significant price formation implications driven by key features of the CAISO's current DAM design, including:

- The participation of supply that is explicitly virtual;
- The participation at CAISO intertie locations of supply that is non-firm or is entirely speculative; and
- The CAISO's day-ahead RUC process, which is the key mechanism for "firming up" the above types of supply by providing out-of-market side payments to a subset of resources in exchange for a commitment to provide additional capacity.

[2] CAISO's DAM design is not unique in its commingling of virtual supply and physical supply, or in its use of reliability commitments outside of the market clearing process in order to supplement the day-ahead energy market solution with additional supply to ensure reliable operations in real-time. However, there are material differences amongst organized markets in the treatment of and requirements for participation by external supply (*i.e.,* imports).

In addition to fundamentally different approaches to the "firmness" of supply, there are several other important price formation topics that will need to be thoroughly discussed as part of the upcoming stakeholder process on a potential western EDAM. These topics include the CAISO's current approach of providing side payments to thermal resources, in the form of bid cost recovery, for start-up and minimum load costs. While similar to many other organized markets, this approach differs from western bilateral markets, where the 8-hour and 16-hour durations of standard energy products generally provide a long enough timeframe over which unit startup and shutdown decisions can be made. Bilateral sellers incurring unit commitment costs will generally factor those costs into the prices at which they are willing to sell, and bilateral purchasers that may be able to avoid unit commitment costs will generally factor those cost savings into the prices they are willing to pay. As a result, the prices of bilateral market transactions generally reflect unit commitment costs.

In contrast, organized markets generally trade hourly and sub-hourly energy. This increased granularity enables a closer representation of evolving grid conditions during the day, but it also renders unit commitment costs largely "sunk" within each individual market interval. As a result, unit commitment costs are generally excluded from energy prices in organized markets, which provide side payments to compensate individual resources whose market revenues do not cover start-up or no-load costs. While these payments make the individual resources that incur commitment costs whole, they also result in *materially lower day-ahead market clearing prices for all other resources*. It will be important to examine whether the use of side payments for start-up and minimum-load costs continues to be necessary, appropriate and applied in a manner consistent with industry best practices, or whether other approaches need to be explored to integrate these costs into market price formation. This should include an examination of how some eastern organized markets have advanced their market designs to integrate unit commitment costs into their market prices for fast-start resources.

The EDAM stakeholder process should also explore CAISO's current approach to shortage and scarcity pricing, out-of-market transactions (including exceptional dispatch), and operator interventions. All of these topics have important implications to day-ahead price formation, and should be examined in light of industry best practices as part of a robust western EDAM stakeholder process with the objective of improving upon existing organized market and bilateral market price formation outcomes.

D. Discussion Of EDAM Design Must Be Aligned With Other Efforts To Enhance CAISO's DAM

The exploration of a workable market design for an EDAM will occur in the context of CAISO's existing DAM processes, where potential enhancements are currently being explored to better address challenges associated with California's growing renewable fleet. Some of the potential changes are significant. In particular, Phase 2 of the DAM Enhancements stakeholder process focuses on enabling CAISO to procure flexible capacity in the day-ahead timeframe. Powerex agrees that such capability is both necessary and appropriate, as the current DAM does not consider CAISO's need to procure, and set aside, flexible capacity to be available to meet potential real-time grid conditions. Consequently, the current DAM solution may frequently schedule flexible units to produce energy rather than conserving "headroom" on those resources in order to ensure there is sufficient flexibility available to the CAISO in real-time, to be deployed as conditions warrant.

Initially, proposals in the DAM Enhancements stakeholder process sought to combine the day-ahead integrated forward market ("IFM") and the residual unit commitment ("RUC") process into a single optimization. A combined optimization would identify the most efficient use of available resources to meet all of CAISO's day-ahead product needs, and all resources providing each of the procured products or attributes would receive compensation at the relevant market-clearing price.

More recent proposals—including the Working Group presentation made to the Market Surveillance Committee on December 7, 2018—signaled a sharp departure from this design objective, however, and instead put forth approaches that would maintain the sequential and separate day-ahead procurement of backstop and/or backfill capacity. Powerex believes this is a step in the wrong direction, as it would perpetuate inefficiencies and price distortions caused by out-of-market procurement of, and side-payments for, the additional capacity that is needed to ensure reliability.

Rather than pursuing enhancements that could have the effect of solidifying an inefficient sequential DAM design, Powerex believes that CAISO should instead defer the discussion on the co-optimization of energy and ancillary services with its new flexible ramping product and its residual unit commitment process until there is greater clarity on whether there is regional support for an EDAM. If stakeholder consideration of an EDAM does move forward, it will necessarily include a comprehensive review of the CAISO's DAM design to identify necessary changes, and will need to do so under a broadly inclusive decision-making framework that balances the diverse interests and priorities of multiple entities and regions.

The remainder of this paper is organized as follows:

- **Section II** examines the key differences between CAISO's current "energy-only" DAM design, and the "firm energy" framework for bilateral transactions throughout the west outside of the CAISO BAA. These differences result in firm energy currently being compensated as "energy only" in the CAISO markets, with the CAISO BAA receiving the reliability benefit of firm supply while "backstopping" supply that is not firm through additional hourly and/or multi-hour backstop and/or backfill capacity committed (and compensated) outside of the market-clearing process.

- **Section III** shows that a day-ahead organized market can achieve efficient resource commitment and accurate price formation and settlements only through the combined and co-optimized procurement of energy, flexible capacity, and ancillary services, largely eliminating the need for a separate residual commitment unit process.
- **Section IV** outlines the key elements of a potential approach to a combined day-ahead market for energy, flexible capacity and ancillary services.

The paper also includes four appendices, providing greater detail and discussion of several topics:

- **Appendix A** provides illustrative examples of a market solution that co-optimizes clearing of day-ahead energy bids with procurement of Flexible Capacity Up and Flexible Capacity Down.
- **Appendix B** includes a closer examination of the role of virtual bidding in a co-optimized market, including examples of how such virtual positions support convergence of the day-ahead and real-time solutions.
- **Appendix C** outlines a proposal for the financial settlement and real-time must-offer obligations associated with the day-ahead products that would comprise a day-ahead co-optimized market design.
- **Appendix D** describes a potential approach to incorporating resource-specific capacity attributes in a day-ahead market design, enabling more accurate assessments of how a resource's energy award may affect the need for flexible capacity, and hence supporting a more efficient day-ahead market solution.

II. The "Energy Only" Approach To DAM Participation And Energy Price Formation Is Inefficient And Differs Greatly From The WSPP Schedule C Firm Energy Product Approach In Day-Ahead Western Bilateral Markets

One of the greatest differences between the current day-ahead bilateral market framework that operates outside of the CAISO BAA and the CAISO's current DAM design is that the CAISO's DAM, similar to other organized markets, is perhaps best described as an "energy-only" market, in which market awards are supported only by financial incentives. This is in stark contrast to the standard energy product traded in the physical day-ahead and real-time bilateral markets outside of the CAISO BAA, which is "firm energy," and which *will* be delivered except in very limited, defined circumstances (*e.g.,* transmission curtailments and reliability emergencies in the source BAA).[3]

The foregoing highlights a critical point as entities evaluate the potential benefits of participating in regional organized day-ahead markets. Namely, while organized markets have the potential to provide substantial benefits - related to more granular hourly and sub-hourly economic dispatch, improved transmission utilization, and more efficient unit commitment decisions - they are also currently less effective than bilateral markets in appropriately recognizing the "bundled" hourly and multi-hour capacity attributes inherent in specific resource technologies. Powerex believes this issue will need to be addressed by CAISO through the exploration of critical DAM enhancements that ensure that all hourly and multi-hour capacity and flexible capacity attributes are appropriately recognized in the CAISO's DAM dispatch, pricing and settlement processes. This may be a key issue for some entities considering participation in a future CAISO EDAM: that the efficiency benefits of an organized market do not come at the expense of failing to appropriately recognize and compensate resources for the key attributes they provide. Powerex believes that the ongoing LMPM/DEB stakeholder process is a good example of CAISO's ability to effectively pursue sound market design approaches that carefully balance the diverse interests of different entities and regions; this same approach will be necessary in designing a DAM framework that works within a broader regional context.

A. The DAM "Energy Only" Design Does Not Require Or Recognize The "Bundled" Capacity Attributes Of Standard WSPP Schedule C Firm Products Traded In Bilateral Markets

The "energy only" market design ignores, in its dispatch, pricing and settlements processes, critical differences in the types of resources—including imports—supplying that energy. In particular, this market design fails to recognize that *physical energy*

[3] The term "firm energy" generally refers to a transaction backed by generation resources that are not relied upon by the source balancing authority to serve firm load within its own area, and that have not already been committed to support transactions with other counterparties. The firmness of the energy source is distinct and independent from the priority of transmission service over which delivery is scheduled. Despite also using the terms "firm" or "non-firm," the priority of transmission service is not related to the firmness of the energy source.

supply from certain types of internal and external resources includes bundled hourly and multi-hour capacity attributes, while energy supply from other types of resources does not. These bundled hourly and multi-hour capacity attributes provide additional reliability value and reduce the need for additional alternative capacity commitments, and associated costs, to reliably serve load. CAISO's DAM, like many organized markets, fails to incorporate these valuable bundled hourly and/or multi-hour capacity attributes in the selection of resources that are dispatched, in the formation of prices, and in settlement processes.

For instance, if an external supplier offers 100 MW of energy sourced from the actual output of a VER, the purchasing entity would need to commit additional hourly and/or multi-hour capacity to backstop these imports to reliably serve demand. The additional backstop capacity is needed both to manage within-the-hour variation in VER output (and associated imports) as well as the risk that the total quantity delivered over the course of the hour may be less than 100 MW. Alternatively, if an external supplier offers 100 MW of energy sourced from a baseload or dispatchable resource, the purchasing entity would generally not need to commit additional hourly and/or multi-hour capacity either to balance within-the-hour variations or to backstop the expected import delivery quantity over the hour.

This example highlights the difference in value to the purchaser—typically in the form of avoiding the need to incur additional capacity commitment costs—between energy deliveries that are bundled with hourly and/or multi-hour capacity attributes (*i.e.,* "firm" energy) and energy deliveries where the availability of the underlying resource is uncertain (*i.e.,* "energy only"). In the bilateral markets that exist in the west outside of the CAISO BAA, the distinction between energy deliveries that are bundled with hourly and/or multi-hour capacity attributes and those that are not is well-established and explicit. More specifically, day-ahead and real-time physical bilateral transactions—particularly transactions traded on automated platforms such as ICE and through brokers—are generally under the terms of WSPP Schedule C ("Firm Capacity/Energy Sale or Exchange Service"). Buyers expect sellers to back these transactions with real physical capacity, ensuring the physical ability to produce and deliver the agreed-upon quantity of energy for the applicable hour(s). The firm nature of the product effectively *bundles energy together with a commitment of hourly or multi-hour capacity* to ensure delivery, and the transaction prices reflect the bundled price of both attributes. Supply sold as WSPP Schedule C Firm Energy includes supply from baseload resources, dispatchable resources and VERs, *which are collectively bundled with sufficient balancing reserve capacity in the source BAA* to ensure delivery for the period of the sale commitment. This bundling of sufficient balancing reserves—of varying quantities depending upon different resource types—creates a standardized commercial product that is fungible across western bilateral markets. Importantly, it also enables the bundled capacity attributes of different resource types, and the bundled capacity attributes of balancing reserve capacity, to be appropriately included in bilateral transaction decisions, prices, and settlement.

Sellers are also able to sell “energy-only”, “non-firm” energy or even “unit contingent” energy in the bilateral markets, but they must generally do so *explicitly* through bilateral transactions that occur outside of the bilateral trading processes for the standard WSPP Schedule C Firm Energy product. Such lower-quality commercial energy products generally lack sufficient bundled balancing reserve capacity in the source BAA to ensure delivery. They are typically traded under WSPP Schedule B (“Unit Commitment Service”) or WSPP Schedule A (“Economy Energy Service”), or some other custom bilateral product, and the seller typically receives a materially discounted price to reflect that the product is not firm.[4] In addition to the formal and explicit *contractual* requirements for firm energy products, adherence to product quality attributes is reinforced by commercial relationships; in Powerex’s experience, buyers are generally very quick to cease transacting with a seller that attempts to sell a firm energy product without also committing the associated balancing reserve capacity needed to ensure delivery.

Since the WSPP Schedule C Firm Energy product is the standard product that is transacted in the bilateral day-ahead markets, this product is also the basis for the most widely quoted and referenced market prices in the west, and hence is important for pricing of a wide range of transactions. For instance, the WSPP Schedule C Firm Energy product is used for day-ahead index price transactions, as well as for forward and futures transactions.

CAISO’s organized markets, in contrast, include a wide range of energy products, all of which are “co-mingled” and treated as equivalent in its day-ahead energy market solution from a dispatch, energy price formation, and settlements perspective. For example, a participant receiving a CAISO energy market award at a CAISO intertie

[4] In certain circumstances, particularly during spring runoff or other periods in which purchasers may have limited ability to back down their resources to absorb purchased energy, non-firm energy products may earn a price premium over firm energy products. These circumstances are typically periods of very low energy prices, reflecting an abundance of available supply.

location *may* deliver a "firm" energy product, such as WSPP Schedule C Firm Energy, but it may also deliver an energy product that lacks sufficient hourly and/or multi-hour capacity attributes to be appropriately *considered* "firm", such as WSPP Schedule B Unit Contingent energy or WSPP Schedule A Non-Firm energy. CAISO market rules also permit sellers at intertie locations to offer energy into the CAISO day-ahead and real-time markets prior to even securing any supply and necessary transmission rights to support physical delivery. At the time the CAISO DAM is run, sellers are not required to disclose the underlying source of supply associated with their market offers. As a result, *the CAISO market does not currently have complete information regarding the "firmness" of energy imports being offered, and cannot distinguish between energy import offers of different product quality*.

Under the current CAISO market design, suppliers of firm physical energy—either at intertie locations or from non-VER internal resources[5]—must compete directly against (1) suppliers of physical energy from sources that are not firm, including unit contingent VER energy and non-firm energy at intertie locations; as well as against (2) suppliers of energy that are either speculative or explicitly virtual in nature. Such direct competition treats these very different sources of supply as fully interchangeable, and results in energy market prices that do not reflect any distinction between the very different capacity attributes inherent in these different energy products, or the different impacts on CAISO's capacity commitment costs.[6]

While a failure to deliver on a WSPP Schedule C Firm Energy transaction in the bilateral markets is generally regarded as non-performance, a failure to deliver on a CAISO energy award carries only financial settlement consequences. Non-delivery of a CAISO market award does not result in the non-delivering seller becoming ineligible to make similar sales in the future.

In effect, the CAISO day-ahead and real-time market clearing prices reflect the prices for an "energy only" product, with market clearing prices paid equally to both suppliers of firm energy and to suppliers of lower-quality products.

The following table summarizes the major differences between energy products included in the transactions and price formation processes in the bilateral markets as compared to the CAISO day-ahead and real-time markets:

[5] The term "non-VER internal resource" is used in this discussion to distinguish between resources located within the CAISO BAA that are VERs and resources that are dispatchable. The distinction is necessary in a framework in which variations in VER output are considered jointly with variations in load for purposes of defining the need for flexible capacity.

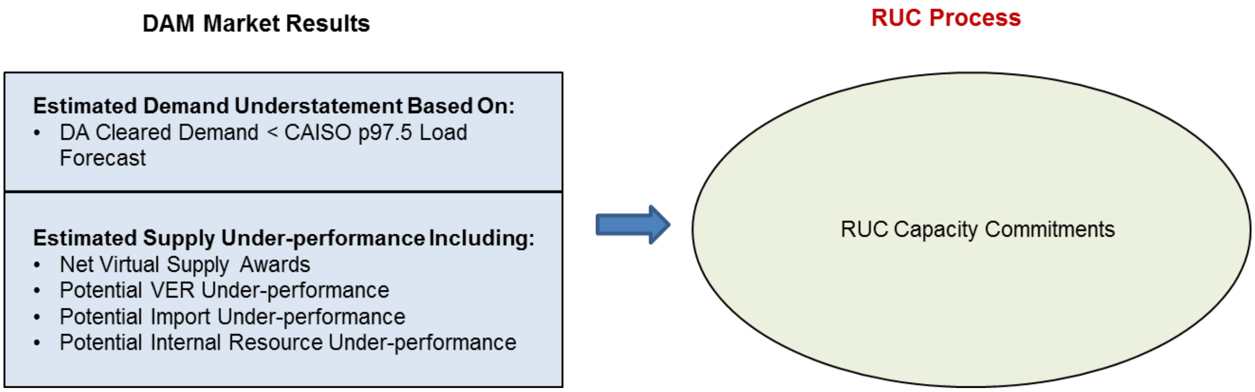
[6] CAISO rules do appear to recognize distinct energy products at its interties of Firm Energy, Non-Firm Energy and Unit Contingent Energy for the purposes of *contingency reserve calculations*. However, CAISO does not define, nor enforce, differences in these energy products from either a dispatch or energy pricing perspective associated with the amount, if any, of capacity that is bundled with specific energy offers at its interties, and the corresponding differences in delivery risk, *independent of any qualifying contingency events.*

Energy Product	Bilateral Commercial Product	Transacted In Bilateral Markets?	Included In Bilateral Price Formation Process For Standard Product & For Price Indices?	Participates In CAISO Day-Ahead and Real-Time Markets (As Fungible Products)?	Included In CAISO Energy Price Formation Processes (As Fungible Products)?
Firm Energy	WSPP Schedule C	Yes	Yes	Yes	Yes
Unit Contingent Energy	WSPP Schedule B	Yes	No	Yes	Yes
Non-Firm Energy	WSPP Schedule A	Yes	No	Yes	Yes
Speculative Supply		No	*N/A*	Yes	Yes
Explicitly Virtual Supply		No	*N/A*	Yes	Yes

B. CAISO DAM Relies On Separate Capacity Commitments And Out-Of-Market Actions To "Backstop" Day-Ahead Energy Awards

In order to protect reliability, given the inclusion of virtual supply and energy imports that are not firm, CAISO separately procures additional hourly and/or multi-hour capacity through its RUC process (or through other out-of-market actions).[7] This procurement effectively "firms up" the portion of energy awards that CAISO *estimates* may not be firm, and that may carry a higher risk of non-delivery.

[7] In addition to day-ahead RUC procurement, CAISO may also procure additional supply to backstop non-delivered awards through operator actions, including exceptional dispatch and real-time load biasing. During the peak net load hours of September 1, 2017, for instance, CAISO procured approximately 6,000 MWh through exceptional dispatch, which appears strongly driven by over 9,000 MWh of intertie market awards that failed to physically deliver. Manual adjustments to real-time load forecasts also appear to be systematically used to commit additional supply prior to the evening peak, with *average* load bias in 2018 of approximately 800 MW during such hours.



Powerex notes that CAISO also uses other out-of-market mechanisms for backstopping and/or backfilling supply under-performance, including exceptional dispatches of other supply resources and upward load adjustments (*i.e* load biasing). For example, to backstop or backfill expected import under-performance, CAISO *may* make manual upward adjustments to the quantity of RUC capacity procured, it *may* engage in out-of-market exceptional dispatches of additional energy supply from either other internal and/or external resources, and/or it *may* adjust its real-time load forecast upwards to acquire additional real-time energy from internal resources and/or imports. In any event, these actions are all "out-of-market" activities, resulting in distortions to dispatch, pricing and settlement outcomes in the CAISO's DAM and/or real-time markets.

Critically, however:

1. CAISO RUC procurement occurs outside of the DAM scheduling and price formation processes for energy and ancillary services;
2. Hourly and multi-hour capacity is not procured to "firm up" *all* DAM energy awards, but only to "firm up" the anticipated portion of energy awards that are estimated to underperform, as they are not already "firm"[8]; and
3. Hourly and multi-hour capacity compensation is provided only to the individual resources committed in the RUC process; it is not provided to firm energy supply that effectively provides the same hourly and multi-hour capacity attributes (*i.e.,* by reducing the need for greater levels of CAISO RUC capacity procurement).

In effect, the CAISO market design enables purchasers to receive the beneficial hourly and multi-hour capacity attributes of day-ahead firm supply (from both firm energy imports and from non-VER internal resources) while compensating such supply as if it were an "energy only" product; CAISO then uses a separate procurement and compensation framework to "firm up" the estimated delivery risk associated with the estimated volume of lower-quality energy products that it also accepts in its market solution.[9]

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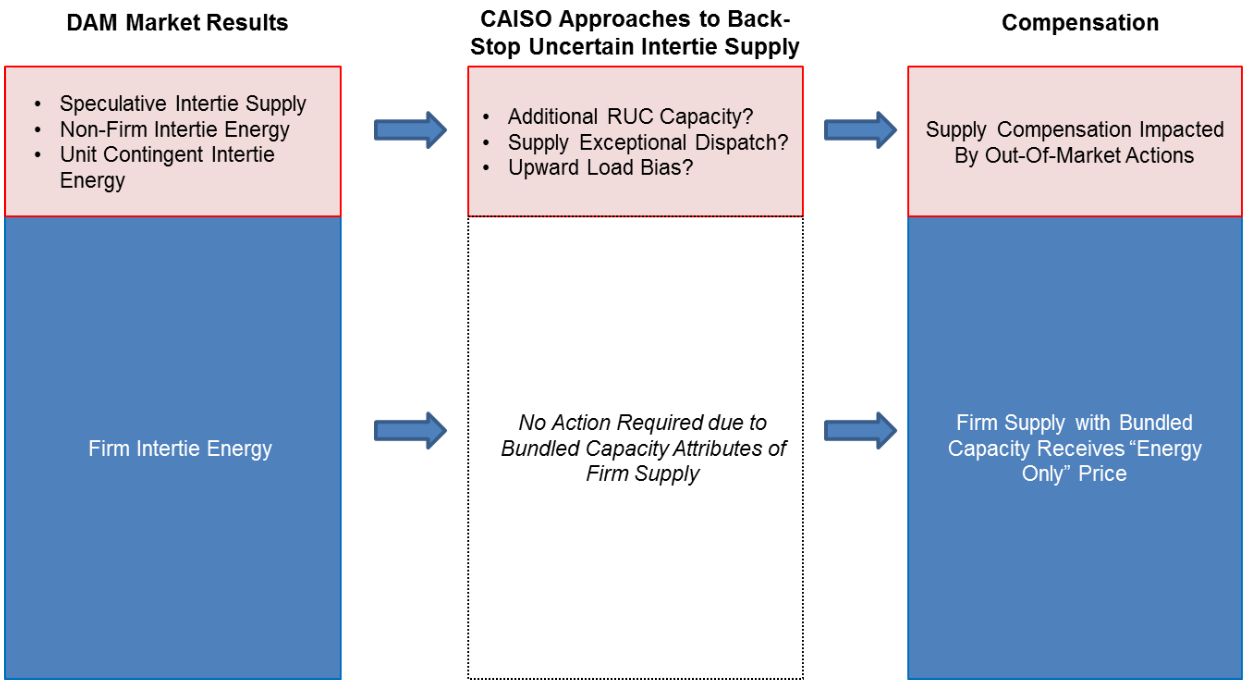
[8] CAISO also procures RUC capacity for other purposes, including when day-ahead bid-in demand is less than anticipated load.

[9] Powerex acknowledges that CAISO is currently contemplating market enhancements in an Intertie Deviations stakeholder process designed to reduce the frequency and magnitude of non-deliveries through CAISO's intertie bidding framework in its real-time market. Importantly, however, these enhancements are only intended to address energy delivery *incentives*, as CAISO is not proposing to either require that all day-ahead and real-time interchange bids and awards represent firm energy, nor is CAISO



C. Price Formation Reflects Differences Between The "Energy Only" Design And Firm Energy Bilateral Products

The above distinctions between transactions for "firm energy" and transactions that are not firm are reflected in the prices at which day-ahead transactions settle. This is perhaps best observed in two key relationships among historical market prices in western bilateral markets:

1. WSPP Schedule B Unit Contingent energy and WSPP Schedule A Non-Firm energy typically transact at significant price discounts to WSPP Schedule C Firm Energy, particularly during times of higher system need; and

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proposing to identify, or differentiate, the bundled capacity attributes of the various energy products CAISO accepts in its dispatch, pricing or settlement of day ahead and real-time energy awards.

Powerex also acknowledges that CAISO is currently considering the implementation of a Flexible Ramping Up and Flexible Ramping Down product that would be procured through the CAISO DAM's co-optimization of energy and ancillary services. While this is a significant step forward, substantial market dispatch, pricing, and settlement inefficiencies will remain unless and until (i) CAISO eliminates all other out-of-market capacity and flexible capacity procurements and compensation frameworks, including its sequential RUC process, and (ii) compensates all resources providing capacity and/or flexible capacity attributes a non-discriminatory marginal clearing price for the attributes provided.

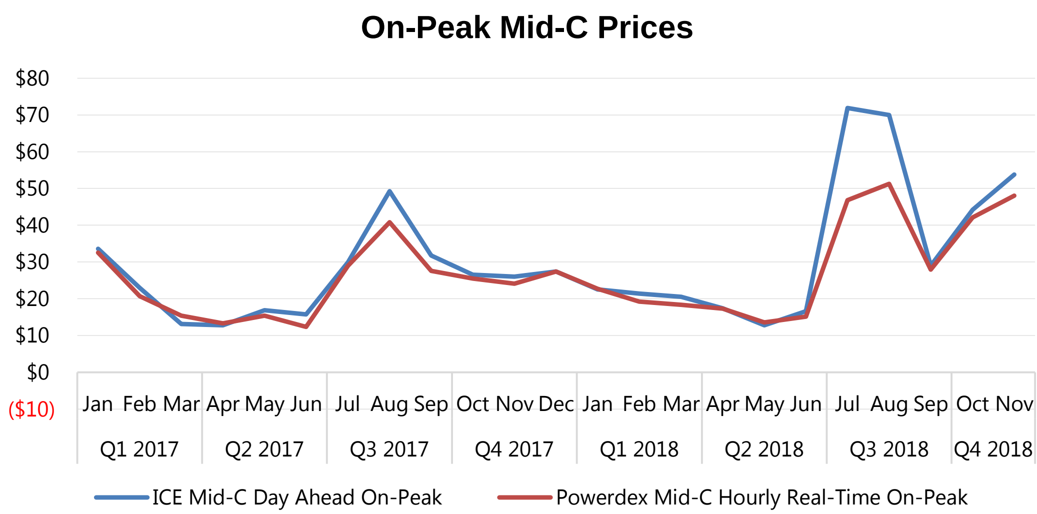
2. Day-ahead WSPP Schedule C Firm Energy prices are systemically higher than real-time WSPP Schedule C Firm Energy prices.

This latter observation highlights the economic benefits of the hourly and multi-hour capacity attributes embedded in the standard WSPP Schedule C Firm Energy product in the day-ahead timeframe versus the real-time timeframe. More specifically, this day-ahead price premium reflects that capacity attributes generally have greater value the further in advance they are provided to the purchaser, as (1) advanced procurement reduces the uncertainty that the purchaser will experience challenges acquiring sufficient supply in real-time to meet demand, and maintain reliability; and (2) day-ahead procurement enables the purchaser to avoid alternative capacity commitment costs that may otherwise be incurred in advance of real-time, such as costs associated with a day-ahead decision to start a thermal resource.

As can be seen in the two charts below, the value of day-ahead WSPP Schedule C Firm Energy is particularly evident during periods of higher system needs, such as summer on-peak periods, when the firm (capacity-backed) attributes of day-ahead WSPP Schedule C Firm Energy are most valuable (*i.e.,* when the buyer cannot simply rely on the availability of abundant sources of alternative real-time energy supply, and/or when the buyer might otherwise incur significant alternative day-ahead capacity commitment costs). Reduced reliability risks and/or avoided alternative day-ahead capacity commitment costs contribute to purchasers generally placing *greater value* on day-ahead firm energy compared to real-time firm energy under such conditions. Moreover, the magnitude of these price differences can be very substantial, reaching $20-25/MWh on average in some summer months, with much higher price differences observed on hours and days with higher demand.

The firm nature of day-ahead standard bilateral market transactions is also reflected during periods of surplus supply, such as spring off-peak periods. A firm energy contract does not only require the seller to deliver, but also requires the buyer to receive the agreed quantity of energy. During periods when many northwest entities may experience challenges *absorbing* high levels of energy production, this firm attribute reflects lower day-ahead upward capacity value (and greater downward capacity value). These downward flexibility challenges thus contribute to bilateral market purchasers placing *less value* on day-ahead firm energy relative to real-time firm energy under these conditions, as day-ahead firm energy purchase commitments exacerbate purchasers' risk of experiencing additional downward flexibility challenges in real-time and/or results in the purchaser having to incur costs to commit additional downward flexible capacity.

Figure 1. Value Of Day-Ahead Firm Energy Upward Capacity Attributes Most Evident In Summer Months



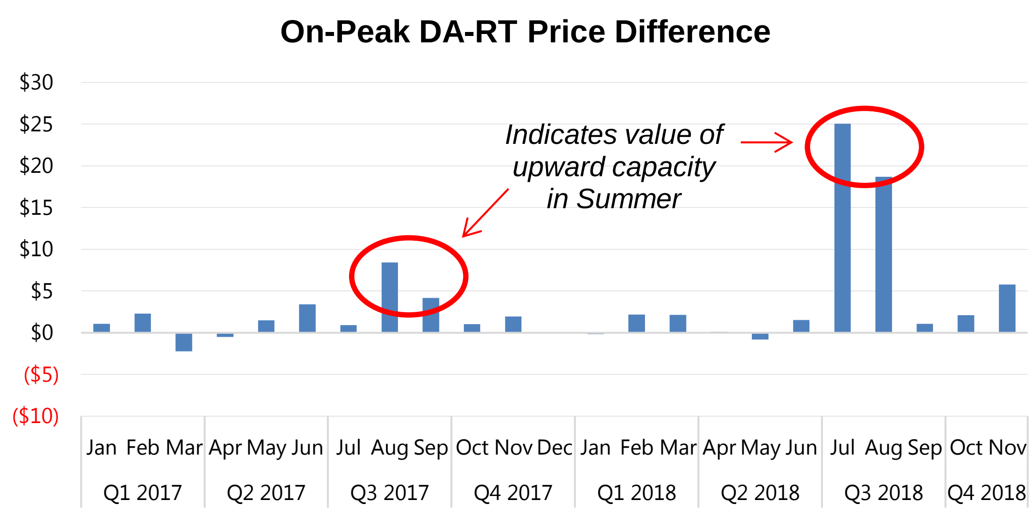
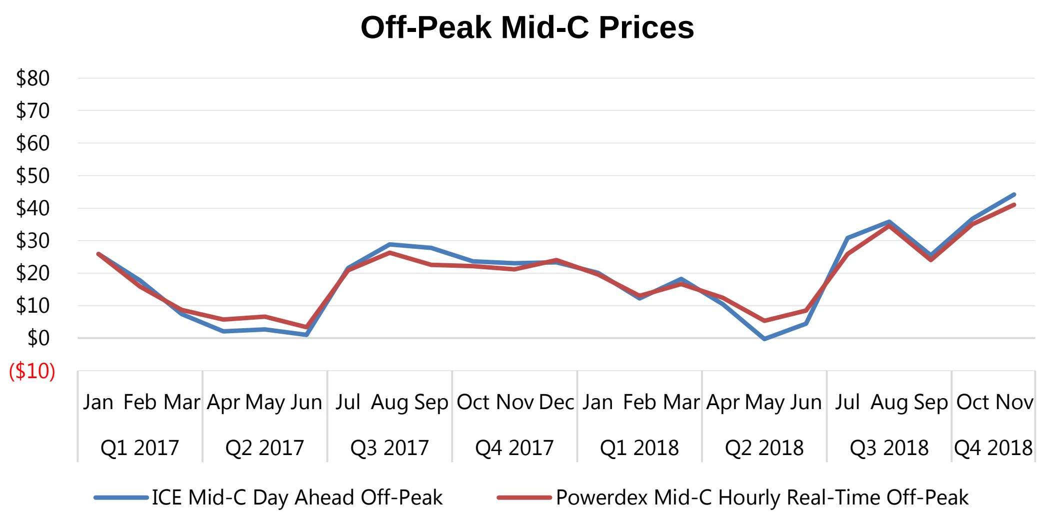
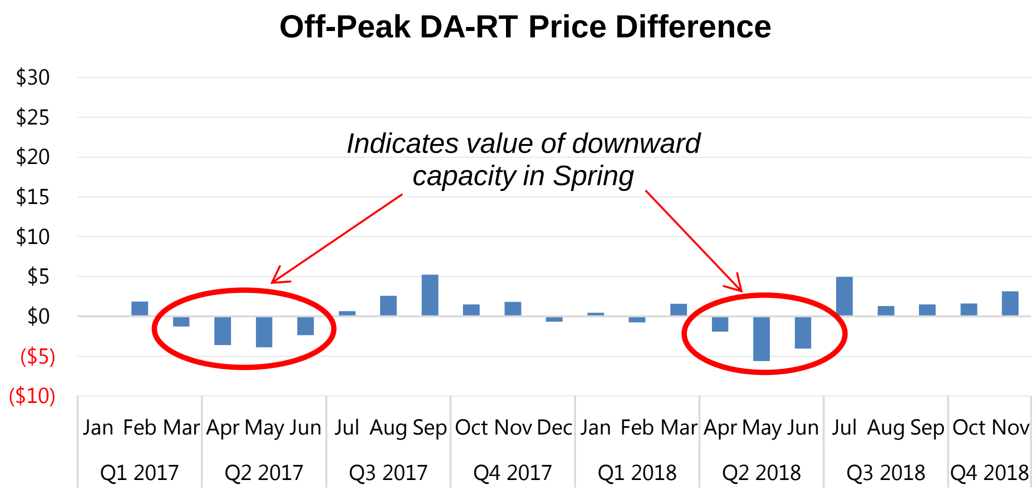


Figure 2. Reduced Value Of Day-Ahead Firm Energy Capacity Attributes Most Evident In Spring And Off-Peak Periods





In other words, not only do WSPP Schedule C Firm Energy products transacted in the bilateral markets often trade at a premium to lower quality energy products, this premium is greatest in the day-ahead timeframe, particularly when upward flexible capacity is the more valuable capacity attribute - which occurs in the majority of hours and months of the year.

While the bilateral day-ahead markets distinguish between energy transactions with different “firmness” attributes, organized markets, including the existing CAISO DAM design, generally does not. Rather, the “energy-only” approach to DAM participation and DAM energy price formation is likely to generally result in prices that are materially lower than day-ahead bilateral market prices. This result can be expected for at least two reasons:

1. As discussed above, the "energy only" approach comingles firm energy products with less valuable products such as unit contingent energy, non-firm energy, explicitly virtual energy, and speculative energy.
2. The CAISO market design includes virtual bidding, whose core purpose is to converge day-ahead prices with EIM prices over time.[10] If the west was to fully transition to an energy-only EDAM with virtual bidding, the resulting day-ahead prices should be expected to converge to the 15-minute prices seen in the EIM.

D. Building Support For A West-Wide EDAM Requires Bridging The Gap Between The Existing Firm Energy Framework And CAISO's "Energy Only" Market Design

CAISO's current "energy-only" DAM design, when coupled with side payments for a limited quantity of hourly and multi-hour "firming up" capacity through a sequential RUC process, may present a significant barrier to regional support for an EDAM, as its price formation practices systematically favor large net purchasing entities and regions at the expense of large net selling entities and regions. Moreover, the impacts of an EDAM will likely extend beyond prices for day-ahead transactions with the CAISO BAA or between EDAM participants. This is because an EDAM would likely impact day-ahead price formation throughout the region, including at major trading hubs like Mid-Columbia and Palo Verde, with repercussions for all forward and day-ahead transactions that trade at those hubs, or that are fungible with supply at those hubs.

A shift across the west to a day-ahead energy-only market paradigm, which includes distortionary out-of-market side-payments to "firm up" supply that is not firm, could result in a very large loss of value for ratepayers of entities and regions with surplus energy and capacity, raising retail electricity rates.

In light of the above, any exploration of an EDAM will require substantial discussion devoted to bridging the gap between the price formation practices based on the WSPP Schedule C Firm Energy product that characterize the existing bilateral markets outside of the CAISO BAA, and the "energy-only" nature of transactions under the organized market framework. Merely applying the rules and practices of existing organized markets, including CAISO's existing energy-only DAM design and sequential RUC

[10] Convergence bidding in organized markets is intended to converge day-ahead prices to expected real-time prices on average and over time. Nevertheless, day-ahead prices can diverge from real-time prices on certain days or months as a result of unpredictable events, or as a result of risks or other frictions associated with convergence bids (including exposure to uplift charges). In addition, CAISO's DAM often includes a substantial quantity of economic offers from external participants. In certain conditions, the CAISO day-ahead system energy price may reflect the external value of day-ahead energy products, and hence reflect the bundled capacity attributes consistent with products under WSPP Schedule C. That is, participation in the CAISO DAM by external suppliers can lead to a degree of convergence between CAISO DAM prices and prices in the bilateral markets. This effect is likely to be significantly diminished if external supply becomes part of an EDAM that is designed as an "energy only" market without any capacity attributes.

framework, to an enlarged geographic market footprint, without significant enhancements, is unlikely to provide a positive business case for certain entities and regions to transition day-ahead activity to an EDAM.

An enhanced day-ahead organized market in which energy-only transactions are backstopped by procurement of appropriate levels of hourly and/or multi-hour capacity, and in which an efficient market clearing price for each product is paid to <u>all</u> suppliers of those attributes, would preserve a highly valued feature of the current bilateral market and, in Powerex's view, could form the foundation of a potentially viable EDAM design that is supported by a wide range of entities in the west.

III. Combined Procurement Of Energy, Ancillary Services And Backstop Capacity (Including Flexible Capacity) Is Critical For Accurate Price Formation And Equitable Compensation

CAISO has expressed interest in combining its day-ahead procurement of energy, ancillary services, and flexible capacity necessary to ensure reliable operation of the grid in real-time. CAISO has cited the more efficient use of physical resources as a chief benefit of such a combined process, and it put forward proposals for a combined day-ahead market in the DAM Enhancements stakeholder initiative. As explained more fully below, Powerex supports transitioning to the efficient, co-optimized procurement of all day-ahead products, and believes such an approach must be a core component of any future western day-ahead market design.

A. Even In A Highly Simplified Design, Flexible Capacity Is Needed To Account For Day-Ahead Forecast Uncertainty

As a starting point, consider a highly simplified "basic" market in which the ISO procures sufficient day-ahead energy to match the ISO's "p50" forecast of load. Following standard security-constrained economic dispatch principles, the day-ahead market would identify the solution that minimizes bid-in supply costs, subject to dynamic constraints on resources, transmission constraints, and other security requirements. Such a solution would minimize the cost of day-ahead procurement to meet the *day-ahead p50 forecast of load.* It would not procure any resources that may be needed if real-time conditions differ from the day-ahead p50 forecast, however. All forecasts have a margin of error, but under this basic design all changes from the day-ahead forecast are met only in the real-time market.

An improvement over the above approach would be to combine the procurement of energy to meet the day-ahead load forecast with the day-ahead procurement of backstop capacity sufficient to meet a reasonable *range of potential* needs; since there is inherent uncertainty regarding how much of this backstop capacity will need to be deployed for energy, a substantial fraction of this backstop capacity will likely need to be provided by flexible resources. For example, the ISO's day-ahead forecast of load may be 30,000 MW, but the 95-percent confidence interval of that forecast may be between 28,000 MW and 32,000 MW. That is, the ISO believes there is a 95% probability that its real-time load will be between somewhere within the range of 28,000 – 32,000 MW. The day-ahead market could be designed to procure:

- 30,000 MW of energy (based on the day-ahead expected value of load);
- 2,000 MW of Flexible Capacity Up (based on the upper limit of the 95-percent confidence range of the forecast); and
- 2,000 MW of Flexible Capacity Down (based on the lower limit of the forecast range).

By seeking to procure both energy and flexible capacity, the day-ahead optimization can minimize the cost of procuring both sufficient energy to meet the day-ahead expected load as well as sufficient capacity to enable the ISO to balance a reasonable range of outcomes in real-time. This approach allows the market to trade off the relative benefit of using a resource to provide energy as opposed to using it to provide flexible capacity, recognizing that the two products may be mutually exclusive. For instance, Flexible Capacity Up can only be procured from a resource with an energy schedule that is less than its maximum output, and that is sufficiently flexible to increase its actual production in real-time. Under this combined procurement approach, a relatively low-priced flexible resource might not be fully scheduled to produce energy, but instead be awarded Flexible Capacity Up. Similarly, the optimization may award energy to a somewhat higher-priced but flexible resource (which can provide Flexible Capacity Down) rather than to a lower-priced but inflexible resource, which can reduce the cost of energy but cannot help the ISO meet its need for Flexible Capacity Down.

Critically, making the most efficient use of resources offered into the day-ahead market requires that the market *simultaneously* consider the alternative (and mutually exclusive) uses of resources. An efficient solution cannot be achieved through a sequential process in which energy is first scheduled through a market-clearing process to meet the day-ahead load forecast, and additional backstop and/or backfill capacity is procured with individual resources through a second process that takes the energy schedules of each resource as a fixed starting point. Under this type of sequential approach, it is entirely possible for flexible resources to be fully scheduled for energy in the first step—in which a resource's ability to provide flexible capacity is ignored—leaving the second step to attempt to procure flexible capacity from a more limited and/or more expensive set of resources. The result of such a process is a less efficient scheduling and commitment of resources to meet the combined set of energy and flexible capacity needs, and associated higher costs.

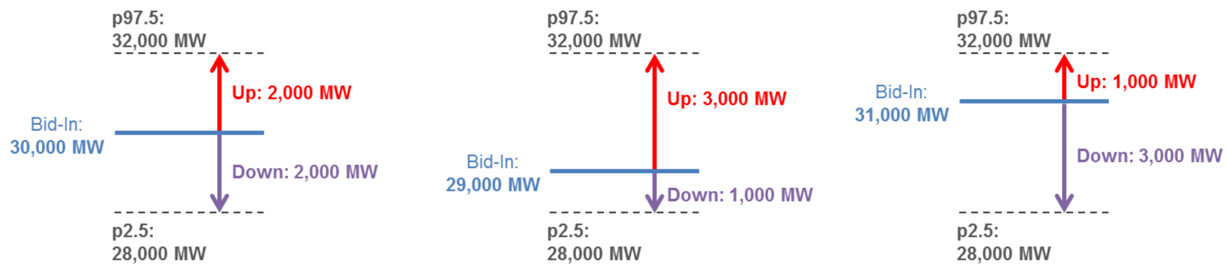
Powerex understands that CAISO is exploring the implementation of new Flexible Capacity Up and Flexible Capacity Down products in its DAM (referred to collectively as the "Flexible Ramping Product") to be procured, priced and settled as part of the DAM's co-optimization approach to day-ahead energy and ancillary services. Although this would be a significant improvement over the status quo, CAISO is not currently proposing to use this new product to procure *all* capacity (including flexible capacity). Instead, CAISO is currently expected to continue to use a sequential RUC process, as well as other out-of-market process (*i.e*. exceptional dispatch and real-time load adjustments) to "backstop" and/or "backfill" understated demand and supply underperformance (including non-firm and explicitly virtual supply).

B. Flexible Backstop Capacity Needs Are Intrinsically Tied To The Quantity And Types Of Supply That Clear The Energy Market

The foregoing discussion centers on procuring Flexible Capacity Up and Down as a result of uncertainty in the ISO's day-ahead load forecast. And while forecast uncertainty is undoubtedly an important driver of the need for flexible capacity, there are several additional reasons why capacity procurement is necessary, especially given the particular design attributes of the CAISO's DAM.

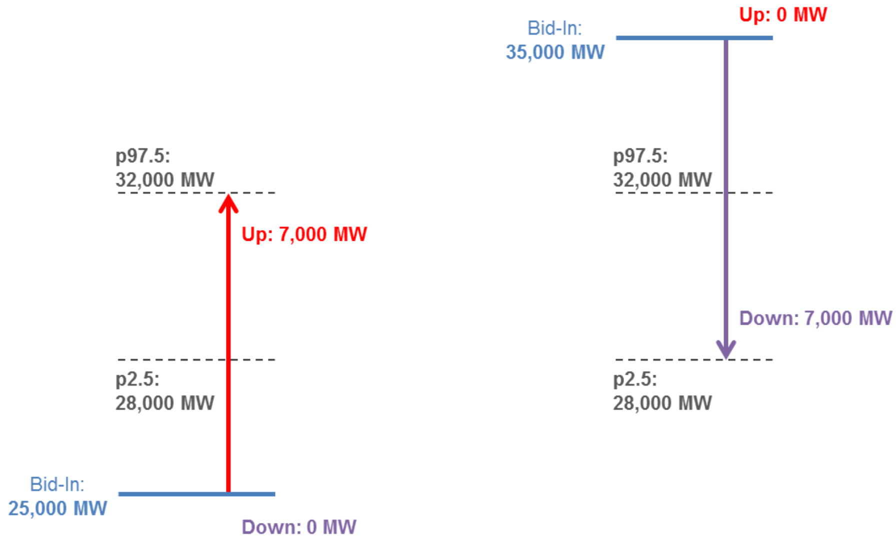
1. *Organized day-ahead markets clear against bid-in demand, not the ISO's load forecast*

Unlike the above simplified example, the CAISO's DAM does not procure resources to meet the CAISO's day-ahead forecast of load; it clears supply offers against demand bids submitted by market participants. This means that the amounts of Flexible Capacity Up and Down that are needed depend not only on the margin of error surrounding the ISO's day-ahead load forecast, but also on the quantity of energy that clears the market. The figure below illustrates how the same ISO forecast range from the prior example (*i.e.,* 28,000 MW – 32,000 MW) *but requires different amounts of Flexible Capacity Up and Down depending on the quantity of bid-in demand from market participants:*



In each of the above scenarios, the bid-in demand was within the range of the ISO's day-ahead forecast. The total flexible capacity needs (*i.e.,* the sum of Flexible Capacity Up and Flexible Capacity Down) were 4,000 MW—matching the range of forecast error—and the bid-in demand simply established how much of that total was procured as Flexible Capacity Up as opposed to Flexible Capacity Down.

Bid-in demand can fall entirely outside of the ISO's forecast range, however. This is illustrated in the figure below.



If bid-in demand was 25,000 MW, as shown on the left-hand panel, then the ISO would need to procure 7,000 MW of Flexible Capacity Up to be able to meet its upper bound load forecast of 32,000 MW. The ISO would not have any need to procure Flexible Capacity Down, however, as its lower bound load forecast (28,000 MW) still requires *additional* supply beyond the bid-in energy quantity. Similarly, if bid-in demand was 35,000 MW, as shown on the right-hand panel, then the ISO would need to procure 7,000 MW of Flexible Capacity Down, which would enable it to meet its full range of load forecast outcomes without any need to procure Flexible Capacity Up.

2. Virtual supply and virtual load also change the need for flexible capacity

A second key feature of organized markets, including the CAISO's DAM, is the participation of virtual supply and virtual demand. It has long been recognized that efficient day-ahead dispatch decisions and price convergence between day-ahead and real-time markets may not be achieved if day-ahead demand bids can only be submitted by load-serving entities ("LSEs"), or if day-ahead supply offers can only be submitted by physical generators. FERC has often required, and CAISO has long enabled, the submission of virtual supply and virtual demand bids in the DAM. Thus, the market clears supply against bid-in demand from both LSEs as well as from virtual demand participants. And supply includes both virtual supply as well as supply associated with internal generators and intertie imports.

The participation by virtual supply in the DAM means that the CAISO's need for flexible capacity is not based solely on the difference between bid-in demand and its upper- and lower-bound forecasts. Rather, the need for flexible capacity will also depend on how much of the bid-in demand is served by virtual supply in the DAM. By definition, any virtual supply that clears in the day-ahead solution, and is needed to serve demand, has to be replaced by physical supply in real-time, and does not contribute to the CAISO's ability to meet the range of potential load forecasts. In other words, a MW of energy awarded to a virtual supply offer displaces a MW of energy awarded to a physical supply offer, increasing the quantity of Flexible Capacity Up (and reducing the quantity of Flexible Capacity Down) that the CAISO needs to procure to achieve its day-ahead reliability objective.[11]

3. *Flexible capacity is needed to account for risk of non-delivery from intertie supply awards that are not "firm"*

A third feature of the CAISO organized market is that even supply that is not explicitly identified as virtual may nevertheless fail to be delivered. This issue is distinct from internal VERs, whose production is subject to forecast error in the same way that load is subject to forecast error. Rather, this issue relates specifically to supply offered at CAISO's intertie scheduling points through the CAISO's intertie bidding framework. Such offers are not required to be supported by physical generation or transmission service at the time they are submitted to the CAISO markets.

As a result, sellers are permitted to rely on procuring supply in the short-term external bilateral markets *after* receiving a CAISO DAM award. This exposes the CAISO BAA to the risk that the seller may be unable or unwilling to procure the supply and transmission necessary to deliver the awarded energy in real-time, and that the CAISO will need to replace that supply from other resources. The inclusion of speculative supply offers at intertie scheduling locations through the CAISO's intertie bidding framework is clearly a deliberate market design choice by CAISO, as evident by CAISO's repeated rejection of stakeholders' suggestions over the years to modify its day-ahead e-Tag requirements, consistent with e-Tagging practices across the west, to support day-ahead physical energy awards.

In a separate stakeholder process regarding intertie deviations, the CAISO has shared extensive data analysis showing that many types of intertie delivery failure are not random events, but appear strongly associated with periods of peak CAISO needs and with periods of tight supply conditions outside of the CAISO BAA.[12] Thus, the inclusion of supply in the DAM that is speculative in nature, and therefore subject to increased performance risk, also affects how much flexible capacity is required for the day-ahead solution to meet the full range of the CAISO's day-ahead load forecast.

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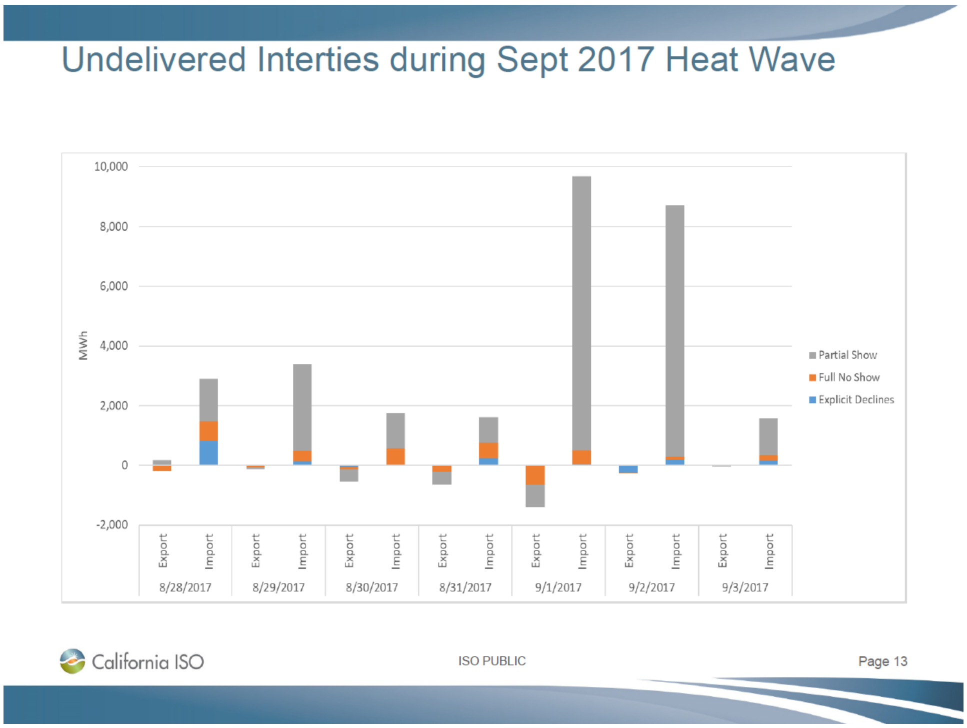
[11] This assumes that day-ahead energy awards to non-virtual supply clears at a quantity within the CAISO's day-ahead forecast range. If day-ahead energy awards to non-virtual supply exceed the upper bound of CAISO's day-ahead load forecast, virtual supply reduces the need for downward flexible capacity, and does not increase the need for upward flexible capacity. Conversely, if day-ahead energy awards to non-virtual supply are less than the lower bound of CAISO's day-ahead load forecast, virtual supply increases the need for upward flexible capacity, and does not reduce the need for downward flexible capacity.

[12] *See* CAISO's December 19, 2018 presentation at the Intertie Deviation Settlement stakeholder call, at 8-16. *Available at:* http://www.caiso.com/Documents/Presentation-IntertieDeviationSettlement-Dec192018.pdf.



Source: CAISO presentation Intertie Deviation Settlement: Draft Final Proposal (December 19, 2018), at 13. Available at http://www.caiso.com/Documents/Presentation-IntertieDeviationSettlement-Dec192018.pdf.

In addition to including supply that is entirely speculative, the CAISO organized market also accepts "unit contingent" and "non-firm" energy products, which may often be curtailed as a result of insufficient balancing reserve capacity being committed in the source BAA to support delivery of the awarded quantity for the applicable delivery period. For example, some BAAs may choose to carry less balancing reserve capacity than what is necessary to fully backstop their exports to serve CAISO hourly energy market awards under all potential conditions. This is particularly true for exports sourced from VER resources, which often require relatively large amounts of balancing reserves to "firm up" the export schedules for the applicable delivery period. The choice by the source BAA to carry a reduced quantity of balancing reserves exposes the receiving BAA (including CAISO) to heightened risks of curtailments on those deliveries compared to hourly energy market awards sourced from resources located in BAAs that provide "firm" energy fully backstopped by balancing reserves.

4. *An efficient day-ahead solution requires simultaneous procurement and compensation of energy and flexible capacity*

The above discussion demonstrates that the CAISO's day-ahead flexible capacity needs are critically dependent on the composition of resources that receive energy awards in the DAM. More specifically, in order to be able to meet the full range of day-ahead forecast load conditions, the CAISO will need to procure:

- Flexible Capacity Up for:
  - The difference between the day-ahead p50 net load forecast and the upper bound of that forecast (*i.e.,* the p97.5 net load forecast);
  - The difference between the day-ahead p50 net load forecast and the total bid-in demand that clears the energy market;
  - The amount of net virtual supply that clears the market; and
  - The potential net under-delivery of cleared non-VER internal physical supply and net imports.
- Flexible Capacity Down for:
  - The difference between the day-ahead p50 net load forecast and the lower bound of that forecast (*i.e.,* the p2.5 net load forecast);
  - The difference between the day-ahead p50 net load forecast and the total bid-in demand that clears the energy market;
  - The amount of net virtual demand that clears the market; and
  - The potential net over-delivery of non-VER internal physical supply and net exports.

An efficient day-ahead market solution cannot be achieved if energy is procured from resources without regard to the capacity attributes of the resource, and thus how the resource selection will affect the need for flexible capacity to be procured. And, as discussed previously, a combined energy and capacity optimization is needed to recognize the tradeoffs that may exist between using a resource to provide energy as opposed to providing flexible capacity.

In addition, a market that jointly optimizes the procurement of energy and flexible capacity is needed to ensure appropriate compensation and charges to all market activity that contributes to meeting CAISO's needs. For instance, whenever firm physical supply reduces the CAISO's need to procure additional Flexible Capacity Up, but non-firm supply does not, then the compensation paid for firm physical supply should be different from the compensation paid to virtual, speculative, unit contingent, and non-firm supply. Conversely, compensation to firm physical supply should also reflect the CAISO's increased need to procure Flexible Capacity Down to protect against oversupply conditions, whereas virtual supply clearly does not increase this need.

Ensuring that all activity receives the market clearing price for the attributes or products being provided is a central tenet of price formation best practices, as it provides strong market-based price signals that encourage participation of the types of resources that can meet the grid's needs.

In contrast, a market design that pays all resources an energy-only price, yet relies on some resources to provide hourly and/or multi-hour capacity attributes beyond energy-only, and then provides compensation for this capacity through side-payments to only a limited number of *additional* resources committed in a separate process, violates these price-formation principles. Such a design suppresses total compensation to suppliers, exacerbates the well-established “missing money problem”, and increases reliance on out-of-market capacity and energy procurement mechanisms and/or forward capacity compensation mechanisms to maintain a fleet with the attributes needed to ensure reliability.

While some may argue that only those resources that *explicitly* provide Flexible Capacity Up or Flexible Capacity Down products should receive compensation for these attributes, Powerex strongly disagrees. Efficient market design requires that all resources that either explicitly provide a particular product or whose attributes *reduce the need for the CAISO to procure that product* receive compensation at the market clearing price for the applicable product. For example, demand response does not explicitly provide energy to the grid; rather, it reduces the need for energy to be procured. This makes demand response a direct substitute for energy supply and makes it appropriate to treat demand resources as energy supply in CAISO’s dispatch, pricing and settlement processes.

It is thus both appropriate and necessary that CAISO correctly recognize that firm energy supply reduces the CAISO’s need for Flexible Capacity Up (while increasing its need for Flexible Capacity Down) in its dispatch, pricing and settlement processes. In addition, a co-optimized market creates strong interdependencies between particular resource types selected to receive energy awards and the need for the system operator to procure physical capacity.

For this reason, an efficient day-ahead market must differentiate between bids and awards that are “energy only” (or purely “financial positions” that settle against the real-time price) from those that directly impact total physical production costs. More specifically, resources are appropriately considered <u>“energy only”</u> and their awards <u>“purely financial”</u> if:

1. The award <u>does not</u> affect the amount of energy supplied or consumed by the applicable resource in real-time; and
2. The award <u>does not</u> increase or decrease the need for additional hourly and/or multi-hour capacity and/or flexible capacity commitments to reliably serve real-time demand.

In contrast, resources are appropriately recognized as <u>physical</u> in nature if either:

1. The award <u>does</u> affect the amount of energy that will be supplied (or consumed) by the applicable resource in the real-time market; and/or

2. The award <u>does</u> increase or decrease the total need for additional hourly and/or multi-hour capacity and/or flexible capacity commitments.

For example, day-ahead demand bids and awards should be, and currently are, appropriately treated as "energy only" or purely "financial" in nature in CAISO's DAM, since day-ahead demand awards do not affect actual real-time physical demand, nor do they change the total quantity of hourly and/or multi-hour capacity and/or flexible capacity that must be committed to ensure reliability. Day-ahead demand bids and awards are thus identical to virtual demand bids and awards. Similarly, day-ahead VER energy bids and awards should be, and currently are, treated as "energy only" or purely "financial" in nature in the CAISO DAM, since the real-time output from a VER is generally based on real-time VER fuel supply, regardless of the day-ahead awarded quantity. Day-ahead energy awards to VERs also do not impact the total quantity of hourly and/or multi-hour capacity and/or flexible capacity that must be committed, as this depends on anticipated VER output in real-time (which is unaffected by day-ahead energy awards).

In contrast, day-ahead bids and awards associated with non-VER internal supply should be appropriately recognized as physical in nature. First, day-ahead awards may directly affect the resource's physical output in real-time, by affecting resource commitment decisions, procurement of fuel supply, and potentially other aspects that may determine real-time production. Second, day-ahead awards to physical resources directly affect the total level of resource commitments for capacity and/or flexible capacity required and procured from other physical resources. That is, a day-ahead energy award from a non-VER internal resource represents a source of physical supply in real-time, and hence reduces the system operator's need to secure a capacity commitment from another resource.

Similarly, day-ahead physical imports and exports, including the "firmness" of each interchange schedule, directly affects the applicable resource's supply in the real-time market, as well as the total level of resource commitments for hourly and multi-hour capacity and flexible capacity required from other resources.

IV. Elements Of A Day-Ahead Market For Co-Optimized Procurement Of Energy And Flexible Capacity

Powerex believes that the day-ahead market needs to be enhanced to provide for the joint and co-optimized procurement of all necessary day-ahead products, including energy, ancillary services, and both Flexible Capacity Up and Flexible Capacity Down. Currently, the day-ahead market is fragmented between the IFM, which co-optimizes only energy and ancillary services, and the RUC process, which commits additional hourly and multi-hour capacity to support reliability through a separate, sequential process. This fragmented approach fails to recognize the critical interdependence between the selection of resources for energy and the selection of resources to provide flexible capacity.

This section outlines the core components of what Powerex believes will enable CAISO to procure the products it needs on a day-ahead basis to ensure reliability, and do so in an efficient and equitable manner consistent with price-formation best practices.

Similar to the current design, the objective function would seek to minimize the bid-in cost of all products that are procured. These products are:

- Energy
- Ancillary Services
  - Spinning Reserve
  - Non-Spinning Reserve
  - Regulation Up
  - Regulation Down
- NEW: Flexible Capacity Up
- NEW: Flexible Capacity Down

The solution would be required to satisfy multiple constraints, including security constraints, resource ramping limits, and transmission constraints, as well as the following key constraints regarding the quantity of each product that must be procured:

- $\text{Energy}_{\text{virtual}} + \text{Energy}_{\text{physical}} = \text{Demand}_{\text{virtual}} + \text{Demand}_{\text{physical}}$
- Ancillary Services: *same as today*
- Flexible Capacity Up >=

  p97.5 Net Load Forecast –
  Energy awarded to non-VER internal physical supply and firm imports +
  p97.5 estimate of Aggregate Negative Uninstructed Deviations of non-VER internal physical supply, imports and exports
- Flexible Capacity Down >=

  Energy awarded to non-VER internal physical supply and firm imports –
  p2.5 Net Load Forecast +

p97.5 estimate of Aggregate Positive Uninstructed Deviations of non-VER internal physical supply, imports and exports

The constraint regarding the quantity of Flexible Capacity Up is generally based on the difference between energy schedules for physical resources and the CAISO's upper-bound estimate of load, with two important refinements. First, energy schedules for VERs are considered by basing the calculation on CAISO's forecast of *net load*, which enables the flexible capacity needs to efficiently incorporate diversity between uncertainty in load and uncertainty in VER output. Second, it is recognized that energy schedules for non-VER physical resources also carry some degree of delivery risk (*e.g.,* due to forced outages of generation or transmission facilities). For this reason, Powerex proposes that CAISO initially procure sufficient flexible capacity to also cover this risk, at a high degree of confidence, based on data on aggregate historical non-performance.

A potential refinement could be to develop more granular resource-specific estimates of non-performance risk for non-VER internal resources and firm intertie resources, and apply it as a "de-rate" to each resource's energy award when calculating the requirement (and compensation) for flexible capacity. This resource-specific approach would have the important benefit of encouraging resources to improve their availability and performance during periods when flexible capacity is of greater value. This is further discussed in Appendix D.

The Flexible Capacity Down constraint largely mirrors the Flexible Capacity Up constraint, except it considers the potential for physical resources to over-deliver energy. Powerex again suggests initially procuring Flexible Capacity Down based on an upper-bound estimate of potential aggregate positive uninstructed deviations of non-VER physical internal resources, imports and exports. Again, a more granular resource-specific approach could be considered at a later stage.

Powerex notes that the foregoing is predicated on CAISO requiring that all energy imports be for firm energy, consistent with the WSPP Schedule C Firm Energy product that is the standard product traded in the external bilateral markets. To the extent CAISO continues to accept energy imports of diverse levels of product quality, it will be critically necessary for CAISO to require sellers to clearly identify the type of energy product being offered to the market. This will require CAISO to have tariff provisions, and enforcement mechanisms, including CAISO requiring day-ahead e-Tags for all firm energy awards. Distinguishing between imports of different product quality is vital for both market efficiency and settlement equity. First, if CAISO cannot distinguish between imports that are backed by firm supply and imports that are non-firm or speculative, it will be unable to determine which import awards require additional procurement of flexible capacity and which ones do not. This will prevent CAISO from accurately identifying the least-cost solution that is consistent with reliable service to load. Second, it will be unworkable and unacceptable, especially in the context of an EDAM, for purchasers in the CAISO market to receive the benefits of higher-quality firm energy products, rely on those hourly and multi-hour capacity attributes to reduce its need to procure flexible capacity, but to provide no market-based compensation to the entities providing that product. Clear and enforced product quality distinctions will enable suppliers of firm energy to be appropriately compensated for those attributes.

Powerex believes that the above framework can achieve a day-ahead solution that clears energy supply against bid-in demand *and* ensures that the CAISO will have sufficient physical resources to meet the full range of its net load forecast, with a high degree of confidence. Some resources will contribute to achieving only one of these two outcomes. For example, energy awards to virtual supply will contribute to satisfying bid-in demand, but will not contribute to meeting CAISO's need for physical supply to meet potential real-time needs. Similarly, a resource that is only awarded Flexible Capacity Up will help the CAISO ensure reliability, but will not contribute to satisfying the bid-in demand for day-ahead energy.

Other resources, however, will be able to contribute to both objectives. In particular, energy awarded to a non-VER internal physical supply will contribute both to satisfying the bid-in demand for day-ahead energy while also contributing to CAISO's ability to maintain reliability in real-time. This is because the energy award is to an identifiable, non-recallable, physical resource, as opposed to a virtual resource or to a speculative or non-firm import with an increased risk of non-delivery. Consequently, even if a non-VER internal physical resource only receives an award for "energy," it also reduces the CAISO's need for Flexible Capacity Up (relative to the energy being awarded to a virtual or non-firm or speculative import resource). In other words, procuring energy from a non-VER internal physical resource is "as good as" procuring energy from a virtual resource *and* procuring additional Flexible Capacity Up toward meeting a given level of demand. The same is true for a firm physical intertie resource.

Importantly, this proposed approach also requires that CAISO institute new rules to ensure that all DAM physical supply awards, including both internal generation and imports, have a must-offer obligation in real-time. This is necessary to enable CAISO to rely on the hourly and multi-hour capacity attributes associated with physical supply awards thereby avoiding the procurement of additional Flexible Capacity Up. In exchange for this must-offer requirement, physical supply awards will receive the opportunity for additional compensation for their hourly and multi-hour capacity attributes, above the compensation provided to virtual supply awards, and any other supply awards that do not include capacity attributes, as further discussed below.

Financial settlement of day-ahead awards must reflect the contribution or cost of each resource that clears the market. Specifically:

Product	Settlement
Physical Demand Awards	Energy LMP
Virtual Demand Awards	Energy LMP
Virtual Supply Awards	Energy LMP
VER Supply Awards	Energy LMP
Non-VER Internal Supply Awards	Energy LMP + Flex Capacity Up MCP – Flex Capacity Down MCP
Firm Intertie Supply Awards	Energy LMP + Flex Capacity Up MCP – Flex Capacity Down MCP
Speculative and Non-Firm Intertie Supply Awards (if permitted)	Energy LMP – Flex Capacity Down MCP
Flexible Capacity Up Awards	Flex Capacity Up MCP
Flexible Capacity Down Awards	Flex Capacity Down MCP

This approach ensures that all resource attributes that are relevant to meeting CAISO's needs are recognized and compensated. For example, a non-VER, internal physical resource and a firm intertie resource would receive the energy locational marginal price ("LMP"), and would also receive compensation for reducing the need for Flexible Capacity Up. Therefore all non-VER, internal physical resources will also receive the Flexible Capacity Up market-clearing price ("MCP") on the quantity of their energy award.[13] This settlement treatment reflects that a firm physical resource does not need to be "backstopped" by additional Flexible Capacity Up procured from other resources.

Energy awards to non-VER internal physical resources as well as all intertie resources also increase the need for CAISO to procure Flexible Capacity Down. Hence it is appropriate for such resources that are awarded energy to be charged the Flexible Capacity Down price on their awarded energy quantity. Importantly, however, resources that are flexible will be able to offer to provide—and may also be awarded for the same delivery period—Flexible Capacity Down, for which they will receive the Flexible Capacity Down price. The net effect is that flexible physical resources can receive compensation for energy and for Flexible Capacity Up (for their Energy award amounts), while potentially have offsetting charges and payments for Flexible Capacity Down (for their Energy award and Flexible Capacity Down award amounts). This

[13] This discussion assumes that pricing of energy will continue to be specific to each node, and hence the settlement price for energy is referred to as the "locational marginal price," or "LMP." The discussion makes no assumptions regarding the locational granularity of Flexible Capacity Up or Flexible Capacity Down products, however, and therefore the prices for these products is referred to as the "market clearing price" or "MCP."

provides flexible resources with potentially greater total compensation than inflexible resources, appropriately reflecting their greater relative contribution to meeting the grid's needs.

Non-VER internal physical resources and firm intertie resources that receive energy awards but do not provide any Flexible Capacity Down will receive revenues that are greater than the energy price whenever the Flexible Capacity Up price is higher than the Flexible Capacity Down price. This is appropriate and efficient as it recognizes the upward capacity value of the bundled hourly and/or multi-hour capacity attributes of this physical supply during those periods when hourly and/or multi-hour capacity attributes have added value to the grid. In contrast, during periods when the Flexible Capacity Down price is greater than the Flexible Capacity Up price, such physical supply will receive a discount from the energy LMP, reflecting the flexibility challenges associated with energy awards to physical resources that do not provide downward flexibility, particularly during periods of oversupply.

Internal VER resources' bids and awards would be treated as virtual supply and would receive the day-ahead energy LMP. However, VER resources would also be eligible to provide Flexible Capacity Down, up to the lesser of (1) their day-ahead energy award; or (2) CAISO's forecast of each VER's resource-specific output. This approach ensures that VERs are encouraged to, and are compensated for, their downward flexibility attributes, while also ensuring any Flexible Capacity Down quantities awarded are consistent with the expected availability of each VER's downward flexibility.

VERs' upward capacity supply contributions to serving demand, as well as VERs' contributions to the need for additional Flexible Capacity Up, will be captured in the CAISO's calculations of Net Load, rather than explicitly settled at a resource-specific level as part of the market solution. However, both VERs' capacity contributions and their contributions to the need for Flexible Capacity Up and Flexible Capacity Down would also need to be incorporated into the allocation methodology for the revenue shortfalls that will arise from the DAM solution, for the unrecovered costs of capacity and flexible capacity that is needed to serve Net Load. Specifically, this methodology must be carefully designed to ensure that:

1. VERs receive appropriate and equitable final settlement value, compared to other resource types supplying the same energy, hourly and multi-hour capacity and flexible capacity attributes and quantities in each market interval; and
2. Each region, in the context of an EDAM, is able to decide how it wishes to sub-allocate VERs' additional contributions to the need for Flexible Capacity Up and Flexible Capacity Down (relative to other resource types) between VERs and/or load.

It is important to note that this is just one possible approach to the treatment of VERs; there are likely to be other potential approaches, and the benefits of each alternative will need to be more fully explored with stakeholders.

Finally, speculative and/or non-firm intertie supply, if permitted at all, would receive the energy LMP and be charged the Flexible Capacity Down price, making it the lowest-valued energy product. That is, the net compensation for non-firm or speculative intertie supply would generally be less than for firm intertie supply, and would also be less than virtual supply. This is appropriate because speculative and/or non-firm intertie supply is akin to CAISO providing a "seller's choice" option to sellers of these products, as the seller can effectively choose whether to deliver energy or not. That is, CAISO cannot *rely* on this supply to be delivered, and hence this supply cannot reduce the need for procure Flexible Capacity Up (as if the supply were virtual). But additionally, CAISO cannot be certain that the supply *will not* be delivered, and hence it must procure additional Flexible Capacity Down (as if the supply were firm).

From a revenue neutrality perspective, as mentioned above, the proposed conceptual market optimization and price formation approach will not fully achieve settlement neutrality, but will require CAISO to allocate the residual supply costs that are not funded through the market solution (*i.e.,* costs associated with the hourly and/or multi-hour capacity attributes of physical supply, and flexible capacity attributes of Flexible Capacity Up and Flexible Capacity Down). This is entirely appropriate and efficient, however, and should not be viewed as a shortcoming of this proposal. These residual cost allocations are the costs associated with procuring, and setting aside, sufficient day-ahead capacity to serve real-time demand, as well as sufficient flexible capacity to respond to uncertainty in real-time demand and supply (*i.e.*, net load). Such cost allocations are analogous to the cost allocations that occur today for contingency reserves and regulating reserves, which, similarly, are costs incurred to meet uncertain real-time conditions that must be allocated outside of the market solution.

Powerex provides several examples in **Appendix A** of its proposed conceptual approach. **Appendix B** provides a detailed examination of the improvements associated with virtual bidding that would be achieved under this approach. **Appendix C** examines the various attributes, proposed real-time must-offer obligations, and proposed settlement treatment of supply products under this approach. **Appendix D** describes a resource-specific capacity contribution approach that would further improve the accuracy of the market solution by considering the resource-specific delivery risk of each firm import and non-VER internal resource.

Powerex believes that many of the concepts outlined above were contained in the CAISO's June 2018 proposal. That is, Powerex is not advocating for a major re-design beyond what CAISO has itself previously explored in the DAM Enhancements stakeholder process. Rather, Powerex urges CAISO to re-establish a combined day-ahead market that jointly procures and compensates energy, ancillary services, and flexible capacity as a core design objective for its day-ahead market enhancements, and to explore such enhancements in the context of its objective of developing a market design that can be a workable basis for an EDAM.

Appendix A: Examples Of Co-Optimized Energy And Flexible Capacity Framework

This appendix presents hypothetical examples to further illustrate Powerex's proposed conceptual framework for a combined day-ahead market that jointly optimizes the procurement of energy, flexible capacity and ancillary services. For simplicity, the procurement of ancillary services is not included in these examples, as Powerex understands the quantity of ancillary services that is procured is determined exogenously based on estimates of generation and load, and is not a function of the market solution itself. The quantity of Flexible Capacity Up and Flexible Capacity Down is intrinsically linked to the quantity of energy awarded to different types of supply resources, however, while the ability of a resource to be awarded Flexible Capacity Up or Down is also a function of how much energy it is awarded.

Assumptions Common To All Examples

In each of the two following hypothetical examples, there are four physical resources (G1 through G4), with the following characteristics:

- G1: 500 MW generator
  - 500 MW of energy offered at $20/MWh
  - 200 MW of Flexible Capacity Up offered at $1/MWh
  - 200 MW of Flexible Capacity Down offered at $2/MWh

- G2: 200 MW generator
  - 200 MW energy offered at $40/MWh
  - 200 MW of Flexible Capacity Up offered at $2/MWh
  - 200 MW of Flexible Capacity Down offered at $2/MWh

- G3: 500 MW generator
  - 500 MW energy offered at $56/MWh
  - 300 MW of Flexible Capacity Up offered at $10/MWh
  - 300 MW of Flexible Capacity Down offered at $4/MWh

- G4: 300 MW generator
  - 300 MW energy offered at $60/MWh
  - 200 MW of Flexible Capacity Up offered at $16/MWh
  - 200 MW of Flexible Capacity Down offered at $4/MWh

Additionally, there is 100 MW of virtual supply.

- In Example 1 it is offered at $46/MWh.

- In Example 2 it is offered at $18/MWh.

The examples below illustrate how these resources may be jointly optimized to provide energy and both Flexible Capacity Up and Flexible Capacity Down, under two different scenarios. Example 1 considers a peak load hour, where Flexible Capacity Up is relatively limited. Example 2 considers a midday or early morning hour, in which both Flexibility Capacity Up and Flexible Capacity Down have similarly low value.

Example 1: Peak Hour

In this example:

Load forecast has:

a) an expected (p50) value of 1,000 MW,
b) an upper-bound (p97.5) value of 1,200 MW,
c) and a lower-bound (p2.5) value of 800 MW.

That is, the forecast has 95% certainty that load will be between 800 MW and 1,200 MW.

Bid-in demand is equal to the p50 load forecast of 1,000 MW.

Bids								
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V1 (Virtual Supply)	100	100	$46.00				
Bid-In Demand	1000						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

The least-cost market solution is shown below:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500	0	100	Energy	$48.00
G2	200	0	0	Flex Cap Up	$14.00
G3	200	300	0	Flex Cap Down	$2.00
G4	0	0	0		
V1 (Virtual Supply)	100	0	0		
Total Awards	1000	300	100		

The market-clearing price for energy of $48 reflects the incremental cost of clearing an additional MW of bid-in demand. A small increase in bid-in demand would require an additional G3 energy award of 1 MW (at an additional cost of $56), but would also reduce the quantity of Flexible Capacity Up that is procured (from G3, saving $10) and would increase the quantity of Flexible Capacity Down that must be procured (from G1, at an additional cost of $2). Thus the net change in bid-in supply costs from an additional increment of bid-in demand is $56 – $10 +$ 2 = $48.

The market-clearing price for Flexible Capacity Up of $14 reflects the incremental cost of increasing G4's energy output by 1MW (at a cost of $60), reducing G3's output by 1 MW (saving $56) and increasing the Flexible Capacity Up award to G3 by 1 MW (at a cost of $10). Thus the total cost of additional Flexible Capacity Up = $60 – 56 + $10 = $14.The market-clearing price for Flexible Capacity Down of $2 reflects the incremental cost of procuring an additional MW of Flexible Capacity Down from G1 or G2.

In terms of settlement, all energy awards receive the energy market-clearing price of $48. Energy awards to the physical resources also receive the market-clearing price of Flexible Capacity Up of $14, and are charged the market-clearing price of Flexible Capacity Down of $2. Physical energy thus receives total compensation of $60 ($48 + $14 - $2), which is $12 *greater than* the market-clearing price of energy alone. This again reflects that an incremental energy award to a physical resource not only procures energy, but also provides *bundled hourly and/or multi-hour capacity attributes* that reduces the need for Flexible Capacity Up and increases the need for Flexible Capacity Down.

Energy awarded to virtual supply receives only the energy price of $48. In this case, the virtual supply receives less total compensation than physical dispatch because the virtual supply neither contributes to meeting the Flexible Capacity Up requirement (with a marginal value of $14), nor does it cause additional Flexible Capacity Down to be procured (with a marginal value of $2).

Finally, all bid-in demand pays the market-clearing price for energy of $48. While this is revenue neutral with respect to the energy compensation for energy awards, it is not revenue neutral with respect to compensation for Flexible Capacity Up and Flexible Capacity Down. This is an expected result, however, as the driver of the need for these products is the capacity needed to serve demand, as well as the flexible capacity needed to respond to uncertainty regarding real-time. The cost of procuring capacity to serve demand, and flexible capacity to cover uncertainty in net load, will result in revenue shortfalls or surpluses that will need to be recovered from users of the grid in an equitable manner. A summary of payments and value received is illustrated below:

SUMMARY OF PAYMENTS AND VALUE RECEIVED							
				Market Clearing Prices			
			Quantity	Total	Energy	Flex Up	Flex Dn
Bid-In Demand Costs	$	48,000.00	1,000	$48.00	$48.00		
Energy Market Receipts	$	48,000.00					
Virtual Supply Payments	$	4,800.00	100	$48.00	$48.00		
Physical Supply Payments	$	54,000.00	900	$60.00	$48.00	$14.00	($2.00)
Flex Cap Up Payments	$	4,200.00	300	$14.00		$14.00	
Flex Cap Down Payments	$	200.00	100	$2.00			$2.00
Energy Market Payments	$	63,200.00					
Energy Market Shortfall	**$**	**(15,200.00)**					
Capacity Value							
Firm Supply Capacity Value	$	10,800.00	900	$12.00		$14.00	($2.00)
Flex Capacity Up Value	$	4,200.00	300	$14.00		$14.00	
Flex Capacity Dn Value	$	200.00	100	$2.00			$2.00
Total Capacity Value	**$**	**15,200.00**					

Example 2: Mid-Day or Early Morning Hour

This example considers the conditions when both Flexible Capacity Up and Flexible Capacity Down have similarly low value. This could occur when a large fraction of the generating fleet has been backed down closer to their minimum output levels, for example.

In this example:

Load forecast has:

a) an expected (p50) value of 400 MW,

b) an upper-bound (p97.5) value of 600 MW, and
c) a lower-bound (p2.5) value of 200 MW.

That is, the forecast has 95% certainty that load will be between 200 MW and 600 MW.

Bid-in demand is equal to the p50 load forecast of 400 MW.

Changes from Example 1 are highlighted in RED.

Bids							
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	200	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V1 (Virtual Supply)	100	100	**$18.00**				
Bid-In Demand	**400**						
P97.5 Net Load Value	**600**						
P2.5 Net Load Value	**200**						

The market solution is shown below:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	300	200	100	Energy	$21.00
G2	0	100	0	Flex Cap Up	$2.00
G3	0	0	0	Flex Cap Down	$2.00
G4	0	0	0		
V1 (Virtual Supply)	100	0	0		
Total Awards	400	300	100		

The market-clearing price for energy reflects the incremental cost of clearing an additional MW of bid-in demand. A small increase in bid-in demand would require increasing G1's energy award by 1 MW (at an additional cost of $20), but would also reduce the quantity of Flexible Capacity Up that is procured (saving $1, as it would need to be reduced from G1 to allow it produce more energy) and would increase the quantity of Flexible Capacity Down that must be procured (from G1, at an additional cost of $2). Thus the net change in bid-in supply costs from an additional increment of bid-in demand is $20 – 1 + 2 = $21.

The market-clearing price for Flexible Capacity Up reflects the incremental cost of procuring an additional MW of Flexible Capacity Up from G2 of $2.

The market-clearing price for Flexible Capacity Down reflects the incremental cost of procuring an additional MW of Flexible Capacity Down from G1 of $2.

In terms of settlement, all energy awards receive the energy market-clearing price of $21. Energy awards to physical resources also receive the market-clearing price of Flexible Capacity Up ($2), and are charged the market-clearing price of Flexible Capacity Down ($2). Thus physical energy receives total compensation of $21, which is *same as* the market-clearing price of energy alone. This again reflects that an incremental energy award to a physical resource not only procures energy, but also reduces the need for Flexible Capacity Up and increases the need for Flexible Capacity Down. In this example, the cost, and value, of the *bundled hourly and/or multi-hour capacity attributes* associated with physical energy are $0, reflecting that the benefits to the market solution of supply that reduces the need to separately procure Flexible Capacity Up are offset by the cost of increasing the need for Flexible Capacity Down.

Energy awarded to virtual supply receives only the energy price of $21. In this case, the virtual supply receives *the same total compensation as* physical supply because, unlike physical supply, the virtual supply does not impose an obligation to procure additional Flexible Capacity Down (worth $2) but also does not reduce the need for Flexible Capacity Up (also worth $2)

Note that G1 receives greater total compensation (of $23) than had it just sold physical energy (for $21), as it is able to sell Flexible Capacity Down (for $2) on 100 MW of its energy award. Thus its ability to adjust its energy award downward in real-time allows G1 to offset charges for Flexible Capacity Down associated with the price for its energy award quantity. This provides an appropriate incentive for resources with downward flexibility to be available during conditions that make that flexibility more valuable to the grid.

Finally, all bid-in demand pays the market-clearing price for energy ($21). As in discussed in Example 1, while this is revenue neutral with respect to the energy compensation for energy awards, it is not revenue neutral with respect to compensation for Flexible Capacity Up and Flexible Capacity Down. Again, this is an expected result. However, in Example 2 the driver of the need for these products is solely the need to procure flexible capacity to respond to uncertainty regarding real-time grid conditions, as there is no net capacity cost, or net value, to the bundled hourly and/or multi-hour capacity attributes of physical supply. The settlement details are illustrated below:

SUMMARY OF PAYMENTS AND VALUE RECEIVED							
				Market Clearing Prices			
			Quantity	Total	Energy	Flex Up	Flex Dn
Bid-In Demand Costs	$	8,400.00	400	$21.00	$21.00		
Energy Market Receipts	$	8,400.00					
Virtual Supply Payments	$	2,100.00	100	$21.00	$21.00		
Physical Supply Payments	$	6,300.00	300	$21.00	$21.00	$2.00	($2.00)
Flex Cap Up Payments	$	600.00	300	$2.00		$2.00	
Flex Cap Down Payments	$	200.00	100	$2.00			$2.00
Energy Market Payments	$	9,200.00					
Energy Market Shortfall	**$**	**(800.00)**					
Capacity Value							
Firm Supply Capacity Value	$	-	300	$0.00		$2.00	($2.00)
Flex Capacity Up Value	$	600.00	300	$2.00		$2.00	
Flex Capacity Dn Value	$	200.00	100	$2.00			$2.00
Total Capacity Value	**$**	**800.00**					

Appendix B: Examining Virtual Bidding Under A Co-Optimized Energy And Capacity Commitment Approach

Like many organized markets, CAISO has implemented virtual bidding in its DAM. The primary market performance objectives of virtual bidding are to:

1. Improve the accuracy and efficiency of the day-ahead market solution through improved resource commitment and dispatch decisions that better reflect expected real-time conditions;
2. Converge day-ahead energy prices to real-time energy prices
3. Mitigate the ability for either buyers or sellers to exercise market power by expanding demand and supply participation and, as a result, reducing the ability for
    a. buyers to potentially suppress day-ahead market clearing prices below expected real-time prices; or
    b. sellers to potentially elevate day-ahead market clearing prices above expected real-time prices

FERC, organized market operators and market monitors, as well as many industry economists have long supported the inclusion of virtual bidding as a necessary component of efficient day-ahead organized markets.

However, virtual bidding in organized markets has not been without its challenges. For example, CAISO markets experienced tremendous challenges with the application of virtual bidding at CAISO intertie locations in 2011, resulting in reported losses of $53 million over the course of a mere 7 months[14]. These losses reflected revenues earned by virtual bidding participants that were largely funded by an increase in uplift charges allocated to load-serving entities. This costly experience exposed some of the market design complexities of virtual bidding, resulting in the CAISO applying, and FERC approving, the suspension, and subsequently the elimination, of virtual bidding at CAISO intertie locations.

CAISO is not alone in experiencing challenges with virtual bidding, as multiple eastern organized market operators and market monitors have also reported virtual bidding performance concerns, resulting in modifications to virtual bidding rules, including the settlement treatment of virtual bidding, in those markets. These virtual bidding experiences highlight the importance of ensuring that virtual bidding mechanisms are carefully designed and implemented.

It is therefore critically important that the application of virtual bidding to a revised day-ahead market that co-optimizes energy and capacity commitments,

[14] *Cal. Indep. Sys. Operator Corp.* Tariff Amendment Eliminating Convergence Bidding at the Interties, Docket No. ER11-4580 (Filed on September 20, 2011)

as described herein, be thoroughly vetted by CAISO staff, CAISO's Department of Market Monitoring (DMM), and industry economists, including the CAISO Market Surveillance Committee (MSC).

There are several key characteristics of successfully designed and implemented virtual bidding mechanisms, including;

1. Virtual supply should be dispatched if, and only if, it lowers the total production cost of the DAM solution. Virtual demand should be dispatched if, and only if, it is higher priced than the resulting increase in total production costs of the DAM solution.
2. Profitability of virtual demand and virtual supply should be based solely on the energy price difference between day-ahead and real-time energy prices.
3. Virtual demand and virtual supply should only be profitable when they converge the day-ahead market solution, from a commitment, dispatch and pricing perspective, to the real-time market solution.

A closer examination of virtual bidding in CAISO's current DAM design shows that each of these key characteristics is absent in certain circumstances, resulting in inefficient day-ahead commitment, dispatch and pricing outcomes. These virtual bidding shortcomings are directly related to the CAISO's "energy-only" market design coupled with its sequential RUC process. For example, virtual dispatches - or lack thereof – may actually *increase* day-ahead production costs after considering the incremental RUC capacity costs resulting from such market outcomes. In addition, while virtual transactions may appear to be profitable based solely on the day-ahead versus real-time energy prices, participants may ultimately lose money due to uplift allocations of those RUC capacity costs. Such uncertain outcomes may discourage participation by virtual bidding participants, further reducing the effectiveness of virtual bidding as a market efficiency-enhancing tool.

The proposed conceptual design framework would address these issues in two important ways. First, the co-optimization of energy and capacity would ensure that the market solution properly considers the incremental flexible capacity cost (or savings) associated with a potential virtual transaction. Second, the market clearing prices would accurately reflect those costs. This would improve both the efficiency of the market outcome itself, as well as ensure that virtual bid profits are properly measured and funded directly through market settlements (and not through uplift allocations).

The following examples highlight that the proposed design framework appears to address the inefficiencies in the existing virtual bidding framework, and can allow virtual participation to improve day-ahead pricing and dispatch outcomes.

Assumptions Common to All Examples in Appendix B

The following set of hypothetical examples in Appendix B share the following assumptions:

- There are four physical resources (G1 through G4), with the following characteristics:
    - G1: 500 MW generator
        - 500 MW of energy offered at $20/MWh
        - 200 MW of Flexible Capacity Up offered at $1/MWh
        - 200 MW of Flexible Capacity Down offered at $2/MWh
    - G2: 200 MW generator
        - 200 MW energy offered at $40/MWh
        - 200 MW of Flexible Capacity Up offered at $2/MWh
        - 200 MW of Flexible Capacity Down offered at $2/MWh
    - G3: 500 MW generator
        - 500 MW energy offered at $56/MWh
        - 300 MW of Flexible Capacity Up offered at $10/MWh
        - 300 MW of Flexible Capacity Down offered at $4/MW
    - G4: 300 MW generator
        - 300 MW energy offered at $60/MWh
        - 200 MW of Flexible Capacity Up offered at $16/MWh
        - 200 MW of Flexible Capacity Down offered at $4/MWh
- The Load forecast has:
    a) an expected (p50) value of 1,000 MW,
    b) an upper-bound (p97.5) value of 1,200 MW,
    c) and a lower-bound (p2.5) value of 800 MW.

Example 1: Currently, Virtual Bids May Be Inefficiently Dispatched When They Increase Total Day-Ahead Production Costs

As previously discussed, an efficient day-ahead market solution cannot be achieved if energy is procured from resources without regard to how the resource selection will affect the need for flexible capacity to be procured. The following example illustrates the potential for a virtual bid to receive a market award despite increasing the total day-ahead production costs when considering the additional capacity commitment required during the RUC process.

In addition to the common assumptions above, assume that:

- There is 100 MW of virtual supply offered at $54/MWh.
- Bid-in demand is equal to the p50 load forecast of 1,000 MW.

Bids								
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V1 (Virtual Supply)	**100**	**100**	**$54.00**				
Bid-In Demand	1000						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

Example 1a: Today's Market Design

First consider the day-ahead market solution based on today's market design, shown below:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500			Energy	$56.00
G2	200			*Flex Cap Up*	*n/a*
G3	200			*Flex Cap Down*	*n/a*
G4	0				
V1 (Virtual Supply)	**100**				
Total Awards	1000				

The market-clearing price of $56 reflects the incremental cost of clearing an additional MW of bid-in demand, which would require increasing G3's energy award by 1 MW. V1 receives a virtual supply award of 100 MW because its $54 offer price is $2 less than the cost of deploying additional energy from G3 at $56.

Assume that under today's market design, the CAISO subsequently runs the RUC process to ensure adequate physical supply is committed to ensure reliability in real-time to meet its p97.5 load forecast of 1,200 MW. The quantity of RUC capacity required depends on the total physical resources committed by the day-ahead market solution. A total of 900 MW of energy was awarded to physical supply, and therefore the CAISO would commit a total of 300 MW of RUC capacity from G3 (valued at a cost of $10) to meet its p97.5 load forecast of 1,200 MW.

A closer examination of this outcome reveals that V1's market award of 100 MW is inefficient after considering the incremental capacity costs associated with the RUC process. The $2 energy cost savings of the market solution (based on selecting V1 at $54 rather than G3 at $56) is more than offset by the out-of-market cost of procuring an additional 100 MW of RUC capacity at $10/MWh to backstop the virtual supply with physical capacity. In other words, awarding 100 MW of energy to V1 and subsequently procuring 100 MW of RUC from G3 results in a net *increase* in production costs of $8/MWh when compared to simply awarding additional 100 MW of energy to G3 in the first place.

Example 1b: Conceptual Market Design

Now consider the outcome of the same scenario using the proposed conceptual market design that would simultaneously consider the costs of both energy and flexible capacity:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		200	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	300	200		Flex Cap Down	$2.00
G4	0				
V1 (Virtual Supply)	**0**				
Total Awards	1000				

The market-clearing price for energy of $48 reflects the incremental cost of clearing an additional MW of bid-in demand, which would require an additional G3 energy award of 1 MW (at an additional cost of $56), but would also reduce the quantity of Flexible Capacity Up that is procured (from G3, saving $10) and would increase the quantity of Flexible Capacity Down that must be procured (from G1, at an additional cost of $2). Thus the net change in bid-in supply costs from an additional increment of bid-in demand is $56 – $10 +$ 2 = $48.

> The market-clearing price for Flexible Capacity Up of $14 reflects the incremental cost of procuring an additional MW of Flexible Capacity Up which would require increasing G4's energy output by 1MW (at a cost of $60), reducing G3's output by 1 MW (saving $56) and increasing the Flexible Capacity Up award to G3 by 1 MW (at a cost of $10). Thus the total cost of additional Flexible Capacity Up = $60 – 56 + $10 = $14.

The market-clearing price for Flexible Capacity Down of $2 reflects the incremental cost of procuring an additional MW of Flexible Capacity Down from G1 or G2.

The market solution above avoids the inefficient outcome associated with the current market design by properly considering both the energy and flexible capacity impacts of dispatching V1 instead of G3. V1 does not receive an energy award because while awarding energy to V1 would represent a $2 energy savings relative to G3, it would also require additional Flexible Capacity Up from G3 at a cost of $10. Instead, the solution simply awards G3 an additional 100 MW. The market solution therefore results in the same upward total capacity commitment of 1,200 MW that would have been procured through the combination of DAM and RUC under the current market design, while avoiding the unnecessary incremental cost of $8/MWh incurred using that approach[15].

Example 1 shows how the proposed market design is consistent with the first key characteristic of a successfully designed and implemented virtual bidding mechanism: virtual supply should be dispatched if, and only if, it lowers the total production cost of the DAM solution. Under the conceptual framework, V1's virtual supply offer of $54 is not awarded because it increases the total production costs of the DAM solution when considering the total cost of energy, Flexible Capacity Up and Flexible Capacity Down. A virtual supply bid would only lower the total production costs of the DAM solution (and would therefore only receive an energy award) if it were no greater than the marginal energy price of $48.

[15] It should be noted that under the conceptual market design, virtual supply would also decrease the Flex Down requirement by 1 MW with a savings of $2. Under today's market design, the need for flexibility in the downward direction is not considered in the energy solution or the RUC process.

Example 2: Currently, Virtual Bids May Inefficiently Fail To Be Dispatched When They Decrease Total Day-Ahead Production Costs

The previous section illustrated the potential for a virtual bid to receive a market award despite increasing the total day-ahead production costs after considering the additional out-of-market capacity costs associated with the RUC process. It is also possible that under today's market design, a virtual bid may *fail* to receive an award even when it could have decreased the total day-ahead production costs.

For the following example, assume that there is 100 MW of virtual **demand** bid at $54/MWh and bid-in demand remains equal to the p50 load forecast of 1,000 MW:

Bids								
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V2 (Virtual Demand)	**100**	**100**	**$54.00**				
Bid-In Demand	1000						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

Example 2a: Today's Market Design

The day-ahead market solution based on today's market design is shown below:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500			Energy	$56.00
G2	200			Flex Cap Up	n/a
G3	300			Flex Cap Down	n/a
G4	0				
Total Supply Awards	1000				
Virtual Demand	**0**				
Cleared Demand	1000				

As in Example 1a, the market-clearing price is $56. V2's virtual demand bid does not receive a market award because its $54 bid price is $2 less than the incremental cost of deploying additional energy from G3 at $56 to meet that demand.

The CAISO subsequently runs the RUC process to ensure adequate physical supply is committed to ensure reliability in real-time to meet its p97.5 load forecast of 1,200 MW. The bid-in load of 1,000 MW was met entirely by physical resources in the day-ahead market solution, and therefore the CAISO would commit 200 MW of RUC capacity from G3 (at a cost of $10) to ensure sufficient physical supply is available to meet its p97.5 load forecast of 1,200 MW.

In this example, the failure to dispatch V2 for 100 MW results in additional costs after considering the RUC costs that would have been avoided if such award had been granted. Specifically, an additional 100 MW of virtual demand would also require an additional 100 MW of dispatch of physical supply from G3 at a cost of $56. This incremental dispatch would increase the total physical capacity committed in the market solution from 1,000 MW to 1,100 MW, which would in turn reduce the total RUC capacity required from 200 MW to 100 MW.

While dispatching G3 at $56 when V2 is only willing to pay $54 represents a $2 energy cost, it would be more than offset by the savings associated with avoiding 100 MW of RUC capacity at $10/MWh. In other words, the result of failing to award 100 MW of virtual demand to V2 and 100 MW of energy to G3 is a net *increase* in day-ahead production costs of $8/MWh.

Example 2b: Conceptual Market Design

Now consider the outcome of the same example using the proposed conceptual market design:

Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		300	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	400	100		Flex Cap Down	$2.00
G4	0				
Total Supply Awards	1100				
V2 (Virtual Demand)	**100**				
Cleared Demand	1000				

As in Example 1b, the market-clearing prices are $48, $14 and $2 for energy, Flexible Capacity Up and Flexible Capacity Down respectively[16].

The market solution above avoids the inefficient outcome associated with today's market design: V2 now receives a 100 MW demand award, and G3 is dispatched an additional 100 MW. As highlighted in the previous example, this outcome is more efficient because although the award to V2 (at $54) would cost $2 by deploying additional energy from G3 (at $56), it would reduce the total Flexible Capacity Up requirement by 1 MW, saving $10. The solution therefore avoids an unnecessary cost of $8/MWh related to upward capacity costs under the current market design[17].

In this case, the conceptual framework is consistent with the principle that virtual demand should be dispatched if, and only if, it is higher priced than the resulting increase in total production costs of the DAM solution. A market award to V2 at $54 decreases the total production costs of the DAM solution when considering the savings

[16] The detailed explanation of the market clearing price for energy and Flex Up is identical to Example 1b. The market-clearing price for Flexible Capacity Down of $2 reflects the incremental cost of procuring an additional MW of Flexible Capacity Down from G2.

[17] It should be noted that under the conceptual market design, an award to virtual demand would also increase the Flex Down requirement by 1 MW with a cost of $2. Under today's market design, the need for flexibility in the downward is not considered in the energy solution or the RUC process.

associated total cost of energy, Flexible Capacity Up and Flexible Capacity Down. A virtual demand bid would lower the total production costs of the DAM solution (and would therefore receive an energy award) provided that it was at least equal to the marginal energy price of $48.

Example 3a: Low Bid-In Demand Results in Inefficient Dispatch

The following examples highlight that virtual bidding under the proposed design framework can allow virtuals to improve day-ahead pricing and dispatch outcomes. First consider an example in which virtual transactions are not allowed and bid-in demand is only 600 MW, well below the p50 forecast of 1000 MW:

Bids								
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
Bid-In Demand	600						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

The least cost day-ahead solution is:

DAM Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500			Energy	$38.00
G2	100	100		Flex Cap Up	$18.00
G3	0	300		Flex Cap Down	$0.00
G4	0	200			
Total Supply Awards	600				
Cleared Demand	600				

The market-clearing price for energy of $38 reflects the incremental cost of clearing an additional MW of bid-in demand. A small increase in bid-in demand would require an additional G2 energy award of 1 MW (at an additional cost of $40), but would also reduce the quantity of Flexible Capacity Up that is procured (from G2, saving $2). No Flexible Capacity Down is required because cleared demand was below the p2.5 load of 800 MW. Thus the net change in bid-in supply costs from an additional increment of bid-in demand is $40 – $2 = $38.

The market-clearing price for Flexible Capacity Up of $18 reflects the incremental cost of decreasing G2's energy output by 1MW (saving $40), increasing G3's output by 1 MW (at a cost of $56) and increasing the Flexible Capacity Up award to G2 by 1 MW (at a cost of $2). Thus the total cost of additional Flexible Capacity Up = $56 – 40 + $2 = $18.

Now assume that in real-time, the load is consistent with the original p50 load forecast of 1,000 MW and all other market inputs are the same. The real-time market solution would be as follows:

Real-Time Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		200	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	300	200		Flex Cap Down	$2.00
G4	0				
Total Supply Awards	1000				
Real-Time Demand Forecast	1000				

In real-time, the market price for energy would be $48, with a Flexible Capacity Up price of $14 and a Flexible Capacity Down price of $2[18].

This simplifying assumption that actual real-time conditions (e.g., bid quantities, bid prices, p50 load forecast, and flexibility requirements) are identical to the day-ahead values allows for a straightforward comparison of the pricing and dispatch outcomes based only on difference between the 600 MW of bid-in demand used in the day-ahead solution and the 1,000 MW load forecast used in the real-time solution.

The comparison of day-ahead and real-time market outcomes highlights that the lower quantity of bid-in demand in the day-ahead market solution results in inefficient pricing and dispatch. First, the day-ahead prices diverge from actual real-time prices as follows:

- The day-ahead energy price of $38 dollars is **too low** relative to the actual real-time energy price of $48
- The day-ahead Flexible Capacity Up price of $18 is **too high** relative to the actual real-time value of Flexible Capacity Up of $14
- The day-ahead Flexible Capacity Down price is $0 is **too low** relative to the actual real-time value of Flexible Capacity Down of $2

Second, the day-ahead commitment of resources is inefficient relative to the actual system needs. Most notably, the highest cost resource (G4) displaces a lower cost resource (G3) in the day-ahead solution in a manner that is inconsistent with the actual real-time dispatch:

[18] An explanation of these prices can be found in Example 1b in Appendix B.

- G4 is the most expensive resource from both an energy and flexibility perspective. In real-time, this resource is not dispatched to supply either energy or flexible capacity as the system needs can be fully met by deploying lower cost resources. In the day-ahead solution, however, G4 is committed to hold 200 MW of Flexible Capacity Up (with a cost of $16).

- G3 is lower cost than G4 from both an energy and capacity perspective. Accordingly, G3 is fully deployed in real-time to provide a combination of energy and Flexible Capacity Up to meet real-time conditions. In the day-ahead solution, however, G3 is only partially deployed.

Example 3b: Virtual Demand Bids Improve Market Efficiency

Now consider the day-ahead solution after including a 400 MW virtual demand bid:

Bids								
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V2 (Virtual Demand)	**400**	**400**	**$50.00**				
Bid-In Demand	**600**						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

The least cost day-ahead solution is:

DAM Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		200	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	300	200		Flex Cap Down	$2.00
G4	0				
Total Supply Awards	1000				
V2 (Virtual Demand)	**400**				
Bid-in Demand	**600**				

As shown above, the virtual demand bid increases the total energy that clears the market from 600 MW to 1,000 MW, resulting in a dispatch and pricing solution that is identical to the ultimate real-time dispatch:

- The day-ahead energy price increases from $38 dollars to $48, consistent with the actual real-time energy price
- The day-ahead Flexible Capacity Up price of $18 decreases to $14, consistent with the actual real-time value of Flexible Capacity Up
- The day-ahead Flexible Capacity Down price increases from $0 to $2, consistent with the actual real-time value of Flexible Capacity Down of $2

In addition, the virtual demand also leads to an efficient day-ahead dispatch of G1, G2 and G3 while avoiding the commitment of G4.

Example 4a: Higher Bid-In Demand Leads to Inefficient Dispatch

Now consider an example in which virtual transactions are not allowed and bid-in demand is 1400 MW, well above the p50 forecast of 1000 MW:

Bids							
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
Bid-In Demand	**1400**						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

The day-ahead market solution is:

DAM Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		300	Energy	$64.00
G2	200		200	Flex Cap Up	$0.00
G3	500		100	Flex Cap Down	$4.00
G4	200				
Total Supply Awards	1400				
Cleared Demand	1400				

The market-clearing price for energy of $64 reflects the incremental cost of clearing an additional MW of bid-in demand. A small increase in bid-in demand would require an additional G4 energy award of 1 MW (at an additional cost of $60), but would also increase the quantity of Flexible Capacity Down that is required from G3 (at an additional cost of $4). Flexible Capacity Up is not required because the cleared demand was above the p97.5 load of 1200 MW. Thus the net change in bid-in supply costs from an additional increment of bid-in demand is $60 + $4 = $64.

Now assume that in real-time, the load is consistent with the original p50 load forecast of 1,000 MW and all other market inputs are the same. The real-time market solution would be as follows (identical to Example 3a):

Real-Time Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		200	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	300	200		Flex Cap Down	$2.00
G4	0				
Total Supply Awards	1000				
Real-Time Demand	**1000**				

In real-time, the market price for energy would be $48, which a Flexible Capacity Up price of $14 and a Flexible Capacity Down price of $2[19].

Again, the simplifying assumption that actual real-time conditions (e.g., bid quantities, bid prices, p50 load forecast, and flexibility requirements) are identical to the day-ahead values allows for a straightforward comparison of outcomes from a pricing and dispatch perspective. These comparisons highlight that the higher quantity of bid-in demand in the day-ahead market solution results in inefficient pricing and dispatch.

First, the day-ahead prices diverge from actual real-time prices as follows:

- The day-ahead energy price of $60 dollars is **too high** relative to the actual real-time energy price of $48
- The day-ahead Flexible Capacity Up price of $0 is **too low** relative to the actual real-time value of Flexible Capacity Up of $14
- The day-ahead Flexible Capacity Down price is $4 is **too high** relative to the actual real-time value of Flexible Capacity Down of $2

[19] An explanation of these prices can be found in examples 1b in Appendix B.

Second, the day-ahead commitment of resources is inefficient relative to the actual system needs in real-time. The total physical supply committed by the day-ahead market solution is 1,400 MW, which is not only above the p50 load forecast of 1,000 MW, it is also well above the CAISO's p97.5 forecast of 1,200 MW. In all but the rarest of cases, the total supply committed in the day-ahead solution will exceed real-time needs. Not only is the total supply committed well in excess of likely system needs, but it leads to dispatch of the higher cost resources:

- G4 is the most expensive resource from both an energy and flexibility perspective. In real-time, this resource is not dispatched to supply either energy or flexibility as the system needs can be fully met by deploying lower cost resources. In the day-ahead solution, however, G4 is committed for 200 MW of energy and results in inefficient increase to the energy price to $60.

- G3 is also over-committed in day-ahead for energy that is unlikely to be required in real-time. 200 MW of G3's capacity would be better utilized as Flexible Capacity Up in the day-ahead market.

- The over-commitment of energy also results in additional Flexible Capacity Down to ensure that CAISO can meet its p2.5 load of 800 MW. This results in a Flexible Capacity Down dispatch to G3 that otherwise would be unnecessary, and an Flexible Capacity Down price of $4.

Example 4b: Virtual Supply Bids Improve Market Efficiency

Now consider the day-ahead solution after including a 400 MW virtual supply bid at $30:

Bids							
Resource	Pmax	Energy MW	Energy Price	Flex Cap Up MW	Flex Cap Up Price	Flex Cap Down MW	Flex Cap Down Price
G1	500	500	$20.00	200	$1.00	300	$2.00
G2	200	200	$40.00	200	$2.00	200	$2.00
G3	500	500	$56.00	300	$10.00	300	$4.00
G4	300	300	$60.00	200	$16.00	200	$4.00
V1 Virtual Supply	**400**	**400**	**$30.00**				
Bid-In Demand	**1400**						
P97.5 Net Load Value	1200						
P2.5 Net Load Value	800						

The day-ahead market solution is:

Day-Ahead Awards and Prices					
Resource	Energy Award	Flex Cap Up MW	Flex Cap Down MW	Marginal Clearing Prices	
G1	500		200	Energy	$48.00
G2	200			Flex Cap Up	$14.00
G3	300	200		Flex Cap Down	$2.00
G4	0				
V1 (Virtual Supply)	**400**				
Total Supply Awards	1400				
Bid-in Demand	**1400**				

As shown above, the virtual supply bid displaces 400 MW of physical supply that was necessary to meet the excess bid-in demand under Example 4a. The virtual supply award result in a day-ahead physical dispatch and pricing solution that is identical to the ultimate real-time dispatch:

- The day-ahead energy price decreases from $60 dollars to $48, consistent with the actual real-time energy price
- The day-ahead Flexible Capacity Up price of $0 increases to $14, consistent with the actual real-time value of Flexible Capacity Up
- The day-ahead Flexible Capacity Down price decreases from $4 to $2, consistent with the actual real-time value of Flexible Capacity Down

In addition to converging the day-ahead and real-time prices for both energy and flexibility, the virtual supply also leads to an efficient day-ahead dispatch of G1, G2 and G3 while avoiding the commitment of G4.

The above examples highlight that the proposed market design framework allows virtual bidding to play an important role in improving the day-ahead market solution in multiple ways. From a pricing perspective, participation of virtual bids can lead to improved convergence of both day-ahead energy and Flexible Capacity Up and Down prices. In addition, the participation of virtual supply can contribute to a more efficient day-ahead commitment of both energy <u>and</u> flexible capacity. Lastly, the compensation to virtual transactions is based on the resulting energy price, and does not result in unpredictable allocations of uplift payments due to capacity costs that were incurred outside of the market solution.

Example 5: Virtual Bids Profitability Is Not Currently Determined Solely By The Difference In Energy Prices Between The Day-Ahead And Real-Time Markets

The proposed co-optimized day-ahead market design will also provide stronger price signals for—and reduce the risk of—virtual bidding relative to the current market design. Currently, virtual supply is paid the day-ahead LMP and is charged the LMP in the 15-minute market. In addition, however, virtual supply awards are allocated a share of the RUC costs. These charges can be highly volatile, however, as they depend not only on the quantity and price of RUC commitments made by the CAISO, but also on the total quantity over which these costs are allocated. The net result is that a rational market participant will not enter into a virtual position simply when the expected value of the real-time and day-ahead price difference is positive, but when it is larger than the estimated value of the uplift charges that may be allocated to such transactions. Since these uplift charges cannot be predicted with reasonable accuracy, and can be very significant, it is likely that they act as a barrier to more efficient levels of virtual activity.

A co-optimized day-ahead market, as outlined above, would not impose the risk of unpredictable uplift charges on virtual transactions. More specifically, virtual supply and virtual demand, just like physical demand, would settle at the day-ahead energy LMP. The costs of procuring Flexible Capacity Up and Flexible Capacity Down that are not recovered through market settlement reflect the need for procure flexible capacity due to uncertainty of net load, and would appropriately be recovered from net load. That is, virtual transactions would not be allocated any additional costs associated with Flexible Capacity Up or Flexible Capacity Down.

Appendix C: Comparing The Attributes, Real-Time Must Offer Obligations And Proposed Settlement Treatment Of Different Energy Products In CAISO Markets

CAISO's current "energy only" DAM design coupled with CAISO's sequential RUC process does not consistently result in efficient dispatch and efficient market prices. The two primary causes of these market inefficiencies are:

1. CAISO DAM's current "energy only" treatment of all energy bids and awards fails to recognize, and appropriately differentiate, the bundled hourly and/or multi-hour capacity attributes of supply offered from different types of internal resources, and from different energy products at intertie locations, in CAISO's dispatch, price formation and settlement processes; and
2. CAISO DAM's sequential RUC process procures, and compensates through side payments, additional upward capacity to support reliability, including quantities determined necessary to "firm up" energy awards to supply that lacks sufficient bundled capacity to ensure performance.

The first of these two causes reflects an incorrect fungibility between the various energy products offered, and awarded, in CAISO markets. More specifically, all internal and intertie energy bids and awards are incorrectly treated as interchangable in the CAISO's energy dispatch, price formation and settlement processes. This incorrect fungibility fails to recognize that different internal supply resources and intertie energy products (1) provide different bundled hourly and/or multi-hour capacity attributes, (2) provide different contributions to reliability, and (3) provide different contributions towards reducing alternative capacity commitment costs.

Table C.1 below compares (1) the different energy, capacity and flexible hourly and/or multi-hour capacity attributes (2) the proposed differing real-time must offer obligations, and (3) the proposed differing settlement treatment of the various energy products offered and awarded in CAISO markets.

TABLE C.1

PRODUCT	ATTRIBUTES PROVIDED BY DAM AWARD	PROPOSED REAL-TIME MUST OFFER OBLIGATION	PROPOSED SETTLEMENT TREATMENT
Flexible Capacity Up	Flexible Capacity Up	FMM Bid Economic	Flex Cap Up MCP
Flexible Capacity Down	Flexible Capacity Down	FMM Bid Economic	Flex Cap Down MCP
Residual Unit Commitment	Flexible Capacity Up	No Longer Exists	No Longer Exists
Non-VER Internal Energy	Energy *and* Capacity	FMM Bid Self Schedule or Economic	Energy LMP + Flex Cap Up MCP – Flex Cap Down MCP
Firm Energy Import	Energy *and* Capacity	FMM Bid Self Schedule or Economic	Energy LMP + Flex Cap Up MCP – Flex Cap Down MCP
Non-VER Internal Energy <u>with</u> Flexible Capacity Down	Energy *and* Capacity *and* Flexible Capacity Down <u>or equivalently</u> Energy *and* Flexible Capacity Up	FMM Bid Economic	Energy LMP + Flex Cap Up MCP
Firm Energy Import <u>with</u> Flexible Capacity Down	Energy *and* Capacity *and* Flexible Capacity Down <u>or equivalently</u> Energy *and* Flexible Capacity Up	FMM Bid Economic	Energy LMP + Flex Cap Up MCP
VER Supply and Virtual Supply	Financial	None	Energy LMP
Bid-In Demand and Virtual Demand	Financial	None	Energy LMP
Speculative and/or Non-Firm Intertie Supply (if permitted)	Energy *and* Increases Need For Flexible Capacity Down (without providing Capacity or Flexible Capacity Up)	None	Energy LMP – Flex Cap Down MCP

Table C.2 below highlights the different settlement treatment that would apply to the different supply awards using three numeric examples. Example 1 is from Appendix A and represents a potential peak hour scenario where Flexible Capacity Up is more valuable than Flexible Capacity Down. Example 2 is also from Appendix A and represents a potential mid-day or early morning hour scenario where Flexible Capacity Up has equivalent value to Flexible Capacity Down. Example 3 is a new example and represents a potential over-supply scenario where Flexible Capacity Down is more valuable than Flexible Capacity Up. These three scenarios and the associated settlement prices for Energy, Flexible Capacity Up and Flexible Capacity Down are as follows:

Example	Energy LMP	Flexible Capacity Up MCP	Flexible Capacity Down MCP
Example 1: Peak Hour Scenario	$48	$14	$2
Example 2: Mid-Day or Early Morning Scenario	$21	$2	$2
Example 3: Oversupply Scenario	$5	$2	$10

Table C.2

PRODUCT(S) AWARDED	EXAMPLE 1	EXAMPLE 2	EXAMPLE 3
Flexible Capacity Up	$14	$2	$2
Flexible Capacity Down	$2	$2	$10
Non-VER Internal Energy	$60	$21	-$3
Firm Energy Import	$60	$21	-$3
Non-VER Internal Energy with Flexible Capacity Down	$62	$23	$7
Firm Energy Import with Flexible Capacity Down	$62	$23	$7
VER Supply and Virtual Supply	$48	$21	$5
Bid In Demand and Virtual Demand	$48	$21	$5
Speculative and/or Non-Firm Intertie Supply (if permitted)	$46	$19	-$5

The above table illustrates the improved settlement outcomes, and associated supply incentives, that can be expected to occur under various grid scenarios.

First, energy supply that provides bundled hourly and/or multi-hour capacity attributes will receive more value than “energy only” supply during conditions when those attributes have value (which is when the Flexible Capacity Up MCP is greater than the Flexible Capacity Down MCP). Conversely, energy supply that provides bundled hourly and/or multi-hour capacity attributes receives less value than “energy only” supply when those attributes have less value, such as during oversupply conditions when physical supply may exacerbate operational challenges Under such conditions, the Flexible Capacity Up MCP will typically be less than Flexible Capacity Down MCP**.**

Second, in all three examples, physical energy supply that also provides Flexible Capacity Down, thereby providing the grid with additional downward dispatch flexibility in real-time, receives higher compensation compared to energy supply that does not provide Flexible Capacity Down. This additional compensation is greatest when the market solution provides more value to additional downward flexibility, such as during oversupply conditions.

Third, virtual supply is generally worth less than physical supply, except under conditions where Non-VER physical supply and firm import supply (that does not also provide Flexible Capacity Down) exacerbate oversupply challenges.

Finally, the proposed treatment of VERs clearly differs from the treatment of Non-VER physical supply. More specifically, the proposed approach treats VER energy awards in the DAM as “energy only” and the same as virtual supply, but while also affording VERs the opportunity to sell Flexible Capacity Down. In circumstances when Flexible Capacity Up is more valuable than Flexible Capacity Down, and hence the grid places higher value on capacity and upward flexible capacity to serve demand, VERs appropriately receive a lower day-ahead settlement price than internal non-VER supply and Firm Import supply. In contrast, in circumstances when Flexible Capacity Down is more valuable than Flexible Capacity Up, such as during oversupply conditions, VERs receive greater day-ahead compensation than internal non-VER supply and Firm Import Supply, particularly if the VERs provide Flexible Capacity Down whereas the other resources do not.

Notably, this proposed approach does not provide VERs with any capacity value associated with VER energy awards in the DAM solution, but it also does not charge VERs for their contributions to the need for Flexible Capacity Up and Flexible Capacity Down. As previously discussed, consideration to VERs capacity contributions as well as their contributions to the need for flexible capacity would need to occur through the development of the allocation methodology for the revenue shortfalls that will arise from the DAM solution, for the unrecovered costs of capacity and flexible capacity. This methodology must be carefully designed to ensure VERs receive appropriate and equitable *final settlement value* compared to other resource types supplying the same energy, hourly and/or multi-hour capacity and flexible capacity attributes and quantities in each market interval. At the same time, it will also be necessary to enable each region, in the context of an EDAM, to be able to decide how *they wish to allocate* VERs additional contributions to the need for upward and downward flexible capacity, relative to other resource types, between VERs and/or load.

Alternatively, there may be other approaches to the treatment of VERs in the market dispatch, price formation and settlement processes worth exploring.

Appendix D: Exploring A More Efficient Approach To Recognizing Resource Specific Capacity Contributions In A Co-Optimized Day-Ahead Market

An important consideration when determining the total upward flexible capacity necessary to reliably balance the grid in real-time is ensuring sufficient capability to respond to the potential non-performance of non-VER internal resources and import transactions in real-time. An internal resource or import that fails to deliver when called upon has multiple negative effects on market operations. First, it requires that CAISO have access to additional upward capacity from other resources to replace the supply that did not materialize. Second, unexpected failures may require CAISO to increase its use of out-of-market tools (such as relying on excessive regulating reserve, or other tools such as exceptional dispatch or load bias). Lastly, and perhaps most importantly, it may require CAISO to carry additional flexible capacity in <u>other</u> hours, in order to anticipate the *potential* risk of non-performance, even if such non-performance ultimately does not occur.

One straightforward approach to account for potential delivery failures is to simply increase the total day-ahead upward capacity requirement based on an assumption of the historical aggregate non-performance rate of all resources and imports. This is not an ideal approach, however, as it could result in the CAISO providing market awards (and flexible capacity payments) to the very same non-performing resources that are increasing the flexible capacity needs in the first place.

An enhanced approach would be to produce a statistical measure of each resource's actual historical performance in real-time during similar periods and/or operating conditions. This would include an assessment of each resource's uninstructed deviations as well as the frequency and magnitude of real-time forced outages relative to its stated day-ahead availability. This would allow CAISO to produce a qualifying upward capacity multiplier for each resource that would limit the maximum allowable contribution of that resource to a quantity that the CAISO can rely upon with a high degree of confidence (e.g., a quantity that is likely to be delivered at a p97.5 confidence level).

This enhanced approach would provide several benefits:

- It would increase the efficiency of the market solution by considering both the direct energy cost of deploying a particular resource or import for energy, and the cost of procuring upward capacity from alternative sources if the resource or import has a history of non-performance under similar conditions.
- It would result in a more appropriate quantity of upward flexible capacity being set aside in a particular hour by considering the performance characteristics of the specific resources that are dispatched at the time, rather than relying on a general assumption of historical average performance for the grid as a whole.
- It would reduce the need for CAISO to rely on out-of-market tools by reducing the reliance on resources that fail to perform when needed.

- It would lead to more equitable outcomes, as upward capacity credit (and associated compensation) would be made available to the resources that actually provide such upward capacity when called upon. This would provide a powerful incentive for resources to improve performance in the hours when upward capacity is most valuable.

The first step in calculating a resource's capacity contribution would be to evaluate the lower bound (*i.e*., the p2.5 tail) of its historical uninstructed deviations (actual output - real-time dispatch) during similar hours. This failure rate would represent the maximum potential delivery short-fall that should be expected in all but the most extreme cases.

Subtracting the p2.5 failure rate from the resource's operating capability would result in the maximum reliable delivery quantity at a p97.5 confidence level. This maximum reliable delivery could then be used to calculate a capacity multiplier for the resource. For example, the capacity multiplier for a 100 MW resource with a failure rate of 10 MW would be calculated as (100 – 10) / 100 = 90%.

Second, the capacity multiplier could be adjusted to reflect the resource's historical real-time forced outage rate, relative to its day-ahead availability. This potential adjustment would reflect that while contingency reserves offer replacement supply within 60 minutes of a qualifying outage, CAISO may require additional resources to make up for energy or capacity shortfalls after the 60-muinute period in which contingency reserves must be restored.

Lastly, the CAISO could further refine the capacity multipliers by providing each resource with a diversity credit to reflect that its individual negative uninstructed deviations during a given period are likely to be at least partially offset by simultaneous positive deviations from other resources in the footprint.

Special Consideration for Imports

A capacity multiplier would also be applied to import transactions. Although imports are generally not resource-specific and may not include explicit forced outage information, a similar performance metric could be applied to each import scheduling coordinator based on the performance of its day-ahead net import transactions. The import capacity multiplier would supplement the additional improvements (such as day-ahead e-Tag requirements) discussed in this paper that would allow CAISO to effectively distinguish firm imports from those that are of lesser quality.

<u>Use of Multiplier in the Market Solution</u>

Recall that firm physical supply can contribute towards meeting the Flexible Capacity Up constraint in two ways: either by supplying energy that is bundled with firm capacity or by receiving an explicit Flexible Capacity Up market award. The use of a capacity multiplier would modify this approach in two fundamental ways:

1) The capacity contribution from a particular resource would be de-rated using its capacity multiplier. For example, a resource that receives a 100 MW energy award and has a capacity multiplier of 90% would contribute 90 MW toward meeting the Flexible Capacity Up Requirement. The Flexible Capacity Up constraint described on page 27 (and reproduced below) would be modified to include the capacity multiplier instead of using an estimate of aggregate uninstructed deviations:

Original Formula:

Flexible Capacity Up >=

p97.5 Net Load Forecast –

Energy awarded to non-VER internal physical supply and firm imports + p97.5 estimate of Aggregate Negative Uninstructed Deviations of non-VER internal physical supply, imports and exports

Revised to:

Flexible Capacity Up >=

p97.5 Net Load Forecast –

Energy awarded to non-VER internal physical supply and firm imports ***** *resource-specific capacity multipliers*

2) In addition to modifying the Flexible Capacity Up constraint, each resource would be constrained to ensure that the sum of its total contributions to the Flexible Capacity Up constraint does not exceed its total reliable supply quantity:

(Energy MW * Capacity Multiplier) + Flexible Capacity Up Award <= Operating Max * Capacity Multiplier

<u>Example</u>

Assume three resources with the following failure rates (based on their p2.5 uninstructed deviations):

Resource	DA Operating Max (MW)	p2.5 Gross Failure Rate (MW)
G1	150	10
G2	150	50
G3	150	2
Total	450	**62**

As shown in the table above, the sum of failure rates for all resources is 62 MW. Now assume that the CAISO calculates the p2.5 of the aggregate uninstructed deviations for the footprint as a whole as 50 MW. This "net failure rate" is lower than 62 MW because it reflects the diversity of performance across all resources, some of which may be over-producing while others are under-producing (and vice versa). The net failure rate then provides each resource with a diversity credit:

Diversity Credit = (Gross Failure Rate - Net Failure Rate) / Gross Failure Rate

Diversity Credit = (62 – 50) / 62 = 19.35%

The diversity credit is used to calculate resource-specific net failure rate as shown in the table below:

Resource	p2.5 Gross Failure Rate (MW)	Diversity Credit	**p2.5 Net Failure Rate (MW)**
G1	10	19.35%	**8.1**
G2	50	19.35%	**40.3**
G3	2	19.35%	**1.6**
Total	62		**50**

Lastly, the resource-specific net failure rate is used to calculate the capacity multiplier for each resource:

Resource	DA Operating Max (MW)	p2.5 Net Failure Rate (MW)	p97.5 Reliable Supply (MW)	**Capacity Multiplier**
G1	150	8.1	141.9	**94.6 %**
G2	150	40.3	109.7	**73.1 %**
G3	150	1.6	148.4	**98.9 %**
Total	450	50	400	

Now assume G1 is dispatched for 100 MW of energy:

1) G1's energy dispatch contributes 100 * .946 = 94.6 MW toward meeting the Flexible Capacity Up constraint described above.

2) G1's maximum upward capacity contribution is 150 * .946 = 141.9 MW. Because G1's energy dispatch contributes 94.6 MW toward the Flexible Capacity Up constraint, G1 could receive no more than 141.9 – 94.6 = 47.3 MW of Flexible Capacity Up Awards.