# Opinion on
# Energy Storage and Distributed Energy Resources Phase 4

by

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## I. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the ISO's Energy Storage and Distributed Energy Resources Phase 4 (ESDER4) initiative.[1] The proposal has several elements. Three of the elements that have drawn significant attention from stakeholders include:

(1) allowing storage facilities bidding into the ISO markets to specify an end-of-hour state-of-charge (EOH-SOC) parameter that constrains operation of the battery in the ISO's real-time markets;

(2) market power mitigation for storage facilities, with a focus on calculation of default energy bids (DEBs); and

(3) effective load carrying capability (ELCC)-based estimation of the contribution of demand response (DR) to system resource adequacy.

In this Opinion, we discuss several issues concerning these elements, and make recommendations concerning their implementation.

Portions of the ESDER4 initiative has been discussed at MSC meetings, including meetings on June 7, 2019, Aug. 19, 2019, May 8, 2020, and, most recently, July 30, 2020. Most of those discussions focused on the marginal costs of operating storage resources and implications for setting default energy bids. Previous phases (Phases 1-3) of the ESDER initiative have also been the subject of previous MSC meetings.

This Opinion is structured as follows. First, in Section II, we discuss the EOH-SOC parameter, with a focus on reasons for the proposal, the inherent limitations of its use in real-time markets with short time horizons, and possible implications for the exercise of market power. Then, in Section III, we consider the complexities involved in estimating the marginal cost of energy storage, and its application to determining DEBs when mitigating local market power. In Section

[1] California ISO, "California ISO, Energy Storage and Distributed Energy Resources Phase 4, Final Proposal," August 20, 2020, http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf .

IV, we consider the general complexities involved in determining capacity credits in resource adequacy ("capacity") markets, and especially the need for, and difficulties involved in, making those calculations for DR.

Our recommendations are summarized as follows:

**End-of-Hour State-of-Charge Parameter Recommendations:** The EOH SOC parameter is an important tool for resource owners to manage storage to help prevent the "end effects" distortions that arise from having too short a time horizon in the market optimization. For example, owners could consider opportunity costs of selling in time periods beyond the optimization horizon and set this parameter in order to conserve energy for use later on, rather than sell it at a lower price prior to the time horizon. This is one standard approach to managing end effects; another is to allow resource owners to specify a $/MWh value of energy to be applied to the last period's ending state of charge, which could even depend on the level of that charge. This would give more flexibility to the operator to tradeoff value of power prior to the time horizon against the value of power later. Resource owners might want to use both approaches to save stored energy for later, with a floor on the SOC and a monetary value for stored energy above that level.

The EOH SOC parameter (and proposed monetary value for the ending SOC) could both be used to exercise market power. We do not propose a hard and fast criterion for detecting and mitigating market power in EOH SOC parameters. We instead suggest that if a storage resource repeatedly (over several days) specifies a EOH SOC value that is much higher than what the day-ahead solution indicates, and if later real-time prices repeatedly do not economically justify that withholding, that the resource could be prohibited for a set period of time from setting a EOH SOC appreciably different than what the IFM indicates is optimal.

**Mitigation of Storage Offers.** We propose adoption of a safe harbor in which storage resources would not have their bids/offers mitigated if they are smaller than some reasonable threshold and/or that are not owned by entities that control other resources that could benefit from higher prices. While such a safe-harbor would arguably be appropriate for all resource types, it would be particularly beneficial in the case of storage resources. This is because of the low potential benefits of mitigating small storage facilities, and the higher potential negative consequences of mitigating storage. Given the rapidly evolving technology and operational practices of batteries, it is easy to imagine a mitigation scheme mis-characterizing the costs and abilities of a storage resource, thereby raising its costs and potentially reducing its value in balancing load over the net load peak hours as well as possibly discouraging investment. If it is proposed now or in a subsequent ISO initiative to also mitigate EOH SOC, then a safe harbor against mitigation should also be defined in that case.

If storage is modeled in market software with explicit representation of energy losses; state of charge and capacity constraints; a $/MWh cycling cost parameter; and either a target SOC for the last interval in the optimization and/or an economic value of energy in storage representing opportunity costs after the time horizon, then the most efficient schedule will result from storage submitting the following information to the market operator:

- constraint parameters;
- the target SOC in the last interval or the value of energy at that time; and
- the $/MWh cost of cycling.

The resulting schedule will be both optimal from a system cost point of view, and profit maximizing if the resource owner does not possess market power. Therefore, to simplify the market power mitigation processes and to better capture opportunity costs, we propose:

- First, that storage owners be allowed to specify SOC parameters for the last interval in the time horizon in both day-ahead and real-time markets, as well as (or instead, if the owner prefers) a value of energy parameter or function for the SOC in the last interval, and
- Second, DEBs omit charging and opportunity costs.

If this system is adopted, then DEBs will need to be developed for energy values to be applied to the last interval in the optimization in case potential market power is identified and to prevent withholding of energy. These DEBs would reflect opportunity costs after the market optimization's time horizon.

It is possible that including recharge and opportunity costs in bids to charge and offers to discharge would not distort scheduling decisions, but we do not see significant advantages to allowing those cost components in bids and offers. This is because those costs are automatically and implicitly considered in the market optimization; difficult to estimate ahead of time (depending as they do on market and shadow prices that are calculated by the market software); and are possibly subject to manipulation in order to exercise market power. The proposed procedures to mitigate market power in energy discharge offers will involve procedures, such as DEB estimation, that will have errors, and furthermore may not be completely effective because EOH SOC parameters and bids to charge can also be used to exercise market power but will not be mitigated.

Opportunity costs in day-ahead and real-time markets are fundamentally different. If opportunity and charging costs are to be included in DEBs, the calculations of DEBs in real-time should reflect the economic principle that sunk costs are not relevant to decisions and price calculations. Extending the time horizon of real-time market software would likely result in better reflection of opportunity costs in storage scheduling, especially if the time horizon is after the evening net load peak. However, there are computational costs to doing so, and the extended model will still not capture the option value of responding to highly variable prices in the RTD time frame.

**Effective Load-Carrying Capability.** The events of August 2020 highlight the importance of realistic characterization of resource contributions to system adequacy. The ELCC concept is a useful and valid theoretical framework for this purpose, and methods for applying it to renewable resources, storage, and demand response need to be improved and applied. More accurate ELCC estimates are also critical to ensure that resource adequacy mechanisms do not over-reward resources whose ELCCs are overestimated while under-rewarding other resources whose ELCCs are underestimated, therefore risking distortions in investment. Methods are needed to include correlations of availability within a class of resources, among different resource classes, and between resource availability and loads; to recognize effects of location and congestion; and to recognize the impact of operational constraints such as unit commitment limitations. This is particularly true for demand response, a resource that will be increasingly important in the future, which is characterized by a diversity of technologies and programs, and whose capability has often been overestimated in the past.

There are various ways to include ELCC in resource adequacy markets. We recommend that incremental last-in ELCC (the marginal ELCC provided by one additional installation of a given class) be the basis for capacity credits and RA payments, and not a mix of average, incremental, and "first-in" and "last-in" types of ELCC. Average ELCC, on the other hand, can be useful for assessing the overall adequacy of a fleet of resources as part of shorter term planning functions. We also recommend that ELCC values for resources not be vintaged for purposes of capacity credits and RA payments, since the contribution of a particular resource to system adequacy may change drastically over time as load patterns, resource mixes, or cumulative installations of that class evolve. There are both equity and efficiency reasons why otherwise identically situated resources should not get different capacity credits simply because one was installed before another.

Finally, we recommend appropriate performance incentives in order to encourage resources, including DR, to report accurate estimates of capacity availability, and to make that capacity available when most needed by the system.

## II. End-of-Hour State-of-Charge Parameter (EOH-SOC)

The CAISO proposal would allow scheduling coordinators to manage use of storage throughout the day by submitting end-of-hour state-of-charge parameters for storage resources in the real-time market to manage use throughout the day. Thse parameters would be submitted along with their offers and bids in the market, and could be updated at the same frequency. The EOH SOC parameter can be a point value, or a minimum and maximum MWh range. The EOH SOC constraint will take precedence over economic outcomes in the market optimization, but will not override ancillary service awards or physical resource constraints.

In the next subsection, we discuss the economic need for a EOH SOC parameter or, as an alternative, an value of energy ($/MWh) that would be applied to the storage level in the last advisory interval in real-time or the 24$^{th}$ hour in the day-ahead market. Section II.B then considers possible market power concerns and how they might be dealt with.

### II.A. The Distorting Effects of Foreshortened Optimization Horizons and the Need for a EOH-SOC Parameter

A fundamental difficulty when optimizing resource schedules is that it is computationally necessary to limit the number of intervals that can be considered in the optimization, while the use of a finite time horizon introduces distortions in the solution and increases costs, in general. These distortions arise from failing to appropriately value the ending state of the system at the end of the time horizon (or, equivalently, failing to evaluate the opportunity cost of decisions that change constraints upon the use of a resource after the time horizon).

As examples, the Integrated Forward Market (IFM) considers 24 hours, which fails to recognize that decisions to shut down or start up so-called "long-start" units should consider the operation of those units over several days or a week. Suboptimal decisions can result if only a single day's benefits of those decisions are considered. As another example, in real-time, the RTPD market looks ahead only approximately 3 hours and the RTD market only an hour. As a result, real-time decisions about use of limited energy facilities (including storage) or facilities that are limited to one start per day may ignore the opportunity cost of using energy or making a start-up now versus saving them for later in the day.[2] Examples of opportunity costs that arise over longer time scales are the value of water in hydropower reservoirs and the opportunity cost of starts when maintenance contracts limit the number of starts per season.

In the optimization literature, distortions arising from truncated time horizons are termed "end effects", and are applicable in many dynamic control and scheduling problems. There are several recognized ways of addressing these distortions. One is to solve over a longer time horizon, for instance extending real-time operations to include a full day of advisory intervals, as suggested in stakeholder comments on the ESDER4 proposal.[3] This approach involves obvious computational challenges, but it has the advantage of calculating opportunity costs by explicitly considering how early decisions constrain possibilities in later intervals. If it is not possible to extend the time horizon, optimization theorists suggest two other possibilities.[4] One is a "primal" approach, in which the ending state of the system is constrained to a value that is most likely to be consistent with the longer run optimization. For instance, the EOH-SOC proposal allows a storage owner to specify a particular value or range within which a battery's state-of-charge must fall at the end of an hour; this allows the owner to prevent the market software from overusing the battery when its energy might be more valuable in an interval beyond the end of the hour.[5] In an earlier version of the ESDER 4 proposal, the ISO had suggested allowing an end of day SOC parameter, which is also a primal approach. The other possibility is a "dual" approach, by placing differential rewards or penalties on different ending states in the objective function. This is the philosophy of "value of water", which places a value on energy left in storage at the end of the optimization's time horizon. A value that reflects the opportunity cost of that energy if saved for later allows the near-term optimization to tradeoff the cost savings from using the energy before the time horizon with the value of uses afterwards.

Thus, the ISO could, in theory, allow a storage resource owner to prevent end effects distortions in real-time markets by either allowing a storage resource owner to specify an EOH-SOC or value of energy in storage, or both. We see advantages to allowing storage owners the flexibility to choose either. The advantage of specifying an EOH-SOC as the ISO proposes is that the resource owner will then know the amount of energy there will be left for the remainder of the

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[2] The estimation of opportunity costs of energy, starts, and operating hours that are relevant to real-time operations was a focus of the Commitment Costs-Default Energy Bids Enhancements initiative of the ISO, https://stakeholder-center.caiso.com/StakeholderInitiatives/Commitment-costs-and-default-energy-bid-enhancements.

[3] Discussed later in this opinion (Section III.C).

[4] Grinold, R. C. (1983). Model building techniques for the correction of end effects in multistage convex programs. *Operations Research*, *31*(3), 407-431.

[5] A more restrictive primal approach is to simply allow the resource to self-schedule over the entire time horizon, but this gives the operator far less flexibility and likely increases system costs; we agree with ISO that allowing the resource owner to specify a EOH-SOC is much preferable.

day,[6] while giving the ISO some flexibility in scheduling the resource in intervals prior to the time horizon. We agree with the ISO that this is advantageous relative to having a resource self-schedule in all intervals in order to preserve a desired amount of energy in storage at the end of the time horizon. The advantage of specifying a value of energy at the time horizon is that if energy prices turn out to be unexpectedly high in intervals prior to the end of the time horizon, the operator has more flexibility to use that energy earlier to meet the unanticipated system need. (This is a two-edged sword; because a resource owner is limited in how often it can update offers, changing conditions might result in too much energy being discharged before the offer can be revised.) The ESDER4 proposal only permits the EOH-SOC. However, a storage owner can express the value of energy through its energy offers in the intervals prior to the time horizon, which can have the same result as stating an ending value of energy.

We see an advantage to allowing a storage owner to express a dollar value of energy to be applied in the objective function to the state of charge at the end of the final advisory interval.[7] If the ISO recognizes energy balances (constraints on SOC evolution) and the rates of discharge and charge in each real-time interval, then the problem of what prices to offer stored energy in each interval is much simpler for the resource owner. The optimal offer in that case for a competitive storage owner is then <u>zero</u>, since the opportunity cost of energy is appropriately considered by valuing stored energy at the time horizon.[8] Differences in opportunity costs that arise over the intervals prior to the horizon because of binding constraints that may arise are automatically accounted for by the market software.

Further flexibility and opportunities for cost savings could be obtained by not only allowing storage owners to specify an ending per unit value of energy, but allowing that value to depend on the amount of energy in storage. When a storage resource has limited discharge capacity (as in the case of batteries with a typical four hours of storage), the marginal value of the first hour's worth of energy is higher than additional increments of stored energy. This is because the first hour can be saved for the most valuable hour later in the day, while (say) the fourth hour's worth of stored energy may fetch an appreciably lower price if price spikes are of short duration and the fourth hour's worth energy has to be discharged when prices are lower. We therefore suggest that the ISO consider giving storage owners flexibility to state a schedule of marginal stored energy values as a function of the total energy in storage at the end of the last advisory interval in the real-time optimization as part of the long-run storage design.[9]

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[6] Subject to certain overriding considerations, such as commitments to supply ancillary services which may require that the EOH SOC be a value different than specified. See the final proposal, p. 6 et seq.

[7] Note that the EOH SOC parameter applies literally to the last interval in the hour, so in order for the SOC parameter to be applied to the very last advisory interval, the proposal would need to revised to allow this parameter to be specified for intervals other than EOH. In the rest of this opinion, we assume that this is possible.

[8] Plus the battery cycling cost, if the battery owner chooses to include it in the discharge offer, rather than the charging bid. Either way can result in cycling costs being correctly considered by the market software, as long as it is adjusted for energy losses (and so would be lower if part of the charge bid), and as long as value of energy correctly accounts for that cost (the value of energy is higher if cycling costs are included in charge bids rather than discharge offers).

[9] This could also be accomplished by allowing storage owners to change offer prices dynamically, but the time lags involved make this less practical than simply having a schedule of marginal values as a function of last interval

## II.B. Market Power and EOH SOC

The ISO's proposal would allow a storage resource to specify an ending SOC (or a range of acceptable values) in the real-time market without considering whether the exercise of market power might be motivating the choice of ending SOC. In particular, the resource might be choosing a relatively high EOH SOC in order to restrict supply in intervals prior to the time horizon in order to exercise market power.

As explained in the next section, the ESDER4 proposal devotes a great deal of attention to calculation of default energy bids in order to prevent exercise of market power. However, no mechanisms are proposed for preventing exercise of market power through specification of EOH SOC parameters that are higher than what competitive firms would choose. A high EOH SOC would reduce energy supply to the market in previous intervals, possibly increasing prices if the resource is large enough to exercise local market power. We are concerned that a storage owner that is determined to exercise market power would avoid raising offers in order to avoid triggering mitigation of offer prices, as discussed below… but could potentially have similar effects on prices by specifying a high EOH SOC. The owner could benefit from high prices for the discharge energy it does sell in those intervals, or for sales from other resources it controls, and then discharging the energy at a time in which price elasticity is lower, or not discharging at all (i.e., maintaining the charge until the next day).[10] If unchecked, this could frustrate the goals of the local market power mitigation (LMPM) system.

Of course, repeated and egregious exercise of market power through the use of high EOH SOC parameters could in theory be detected by the CAISO's Department of Market Monitoring, and brought to the attention of FERC. However, FERC referral is a blunt instrument, with uncertain dissuasive value and the potential to discourage efforts to efficiently manage resources if this were applied too broadly.

Because use of the EOH SOC parameter could result in frustration of the objectives of local market power mitigation for storage, it is very important to closely monitor the use of that parameter by resources whose owners are identified by the ISO's LMPM procedures as having local market power, and if needed to devise appropriate remedies. We do not propose a hard and fast criterion for detecting and mitigating market power in EOH SOC, but instead suggest the following. If a storage resource repeatedly (over several days) specifies a EOH SOC value that is much higher than what the day-ahead solution indicates, and if later real-time prices repeatedly do not economically justify that withholding, that the resource could be prohibited for a set period of time

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energy in storage. The schedule would be nonlinear (with a diminishing marginal value if there is more energy in storage), and would therefore complicate the market software by adding variables and constraints in order to provide a piecewise linear approximation of the schedule.

[10] Such strategies for storage resources – withhold when elasticities are low/prices are high, and discharge when elasticities are high/prices are low -- have been long recognized (e.g., Bushnell, J. (2003). "A mixed complementarity model of hydrothermal electricity competition in the western United States." *Operations research*, *51*(1), 80-93). It has been suggested, however, that fixing a high EOH SOC might be a more difficult way to exercise market power than by directly raising offers, as a guess has to be made as to how much withholding is necessary to raise prices in a way that increases profit.

from setting a EOH SOC appreciably different than what the IFM indicates is optimal. We suggest exempting storage resources from this mitigation procedure if they qualify for a safe harbor similar to what is proposed in III.A below, or if there are no other resources positioned to profit from the withholding of the battery's production.

## III. Local Market Power Mitigation and DEBs for Storage

Presently, battery storage is not subject to local market power mitigation in the CAISO markets. The proposal would subject charging bids and discharge offers to mitigation. In the final proposal, a default energy bid that would be applied to all storage resources is presented. This default energy bid is to account for cycling costs, charging costs, opportunity costs, and losses. Storage resources will also submit technical parameters that are to be stored in the master file and subject to verification. The proposed DEB calculations have been revised since the initial straw proposal recommendations, and the ISO announced in August 2020 that DEBs to be used in the day-ahead market will undergo further policy development in the coming months.

In the following subsections, we first propose a safe harbor for smaller storage resources (Section III.A). We then analyze marginal costs of storage and draw conclusions about what should be included in DEBs and, importantly, what should be excluded (Section III.B). We propose a simpler DEB calculation that would be applicable if an EOH SOC is specified for the final interval in the market optimization and/or if an economic value of energy is provided for that EOH SOC. Finally, in Section III.C, we make some additional observations about DEB calculations, including mitigation of charging bids, the possibility of mitigating charge-discharge bid spreads rather than separate mitigation of each, and the potential improvements in storage management and opportunity cost calculations if a longer optimization horizon is used in the real-time market,

### III.A. "Safe Harbor" for Small Storage Resources

Grid-scale battery storage facilities range in size from a handful of MW to potentially as much as several hundred MW. Under present CAISO LMPM procedures, when and where potential local market power is identified by the ISO's screening procedures, bid mitigation is applied to all resources in the relevant locations and not just resources controlled by jointly pivotal entities.

However, in the case of relatively small battery resources, such mitigation is unlikely to make a difference in market outcomes unless those resources are controlled by entities with significant amounts of other resources in their portfolio. Independent small battery resources of, say, 5 MW or less, are highly unlikely to be able to materially affect prices except in very small load pockets or under highly unusual circumstances.

We suggest that this reality be recognized by the ESDER4 LMPM proposal by providing a safe harbor in which mitigation of offers to the default energy bid is not applied when storage resources are below some de minimis size, and are not controlled by an entity with other resources in the relevant area. This de minimis size could be some fraction of the capacity of impacted flow constraints for which the dynamic LMPM test has triggered mitigation, or some more blunt MW threshold. Alternatively, the philosophy of the CAISO's present system market power mitigation proposal[11] could be adopted, in which mitigation is applied only to resources controlled by entities that are found to be jointly pivotal, and other resources are exempt.

While such a safe-harbor would arguably be appropriate for all resource types, it would be particularly beneficial in the case of storage resources. This is because of both the low potential benefits of mitigating small facilities, and the higher potential negative consequences of mitigating storage. As we discussed above, the mitigation of energy bids may not be very effective in limiting the market power of batteries due to the ability of batteries to physically withhold via the state-of-charge or other means. At the same time, mitigation may impede legitimately competitive operations of storage resources. Given the rapidly evolving technology and operational practices of batteries, it is easy to imagine a mitigation scheme mis-characterizing the costs and abilities of a storage resource, thereby raising its costs and potentially discouraging investment.

### III.B. Marginal Costs and DEBs for Storage

Under the CAISO LMPM approach, when the offer of a resource is mitigated, it is mitigated to the default energy bid. The CAISO calculations of DEBs has become increasingly complicated over the last few years for several reasons. For instance, the EIM has expanded to include balancing authorities with large hydro facilities, in which the value of water is determined by uncertain prices for hydro output several days or even many months in the future. As another example, there is recognition that many resources have limitations on energy, hours of operation, and number of starts that give rise to opportunity costs that can depend on prices later in the day or later in the year, depending on the nature of the constraints. As yet another example, it turns out that wear-and-tear and maintenance costs, greenhouse gas costs, and other non-fuel related expenses can be very important for many types of units. The surprising way in which batteries have been used so far in the CAISO markets illustrates the latter complication, as battery owners are concerned about how deep cycling of batteries can shorten battery life when operated to arbitrage energy prices, and so most batteries are instead operated to provide ancillary services.

The CAISO's proposal outlines four major categories of expenses that determine the marginal costs of discharging a battery, and which the proposal argues should be considered in determining an DEB: costs of charging energy, energy losses during the charge-discharge cycle, opportunity costs from discharging and selling energy now rather than at another time when prices may be higher, and cycling and maintenance costs. These get boiled down in the CAISO's proposal to the following formulation of the DEB for discharge energy:[12]

DEB =
1.1*MAX(Cost of charging energy (accounting for losses) + cycling cost, Opportunity cost)

This formula is intended to be an approximation of the cost to the storage unit of discharging one more MWh in interval *t*. More precisely, it is the decrease in the storage unit's net revenues if the unit increased its discharge by 1 MWh in interval *t* without earning any revenue from that incremental discharge. This decrease in net revenue results either from an increase in costs (more

[11] https://stakeholdercenter.caiso.com/StakeholderInitiatives/System-market-power-mitigation

[12] Final Proposal, p. 22.

charging, more cycling costs) or a decrease in revenues at other times (from foregone sales). So if the price in *t* received for that incremental discharge is less than this incremental cost, the storage unit will be worse off.

We have the following comments about each of the components of this cost and how they are considered in the DEB calculation.

1. *Cost of charging energy and losses.* These are relevant in the day-ahead context when a battery would not be fully charged in the IFM's optimal schedule, and the optimal response to an increase in output in interval *t* would be to increase the amount of charging that takes place in some earlier interval *t*'. That *t*' would be identified as the earlier interval with the lowest energy price among all intervals in which (i) additional charging is feasible (the battery is not being charged at its maximum possible rate).and (ii) would make more energy available in *t* (which means that the battery storage is never fully emptied or filled between *t*' and *t*), and additional charging is feasible.

   In a day-ahead optimization, the cost of charging is implicitly included in the optimization, if the optimization includes all relevant state-of-charge and capacity constraints. If the optimal response to increasing discharge in *t* is an increase in charging at an earlier *t*', then the market software will automatically and optimally tradeoff the benefit (price received for the discharge in *t*) with the cost (price paid for the charge in *t*', adjusted for losses). *There is therefore no reason for discharge offers to include the charging price in the IFM. This means that the DEB in the IFM does not need to include the charging prices.*

   However, the picture is muddied in real-time because the cost of charging energy is theoretically irrelevant in a real-time context. This is because a basic principle of economics is that sunk costs are irrelevant to going-forward decisions and market-based pricing. If a storage resource sells another MWh in *t* in real-time, it is too late to charge in a period before the binding interval, and what the charging cost were is irrelevant.[13] *Therefore, binding interval DEBs in the real-time markets should not include charging prices. Advisory interval DEBs in those markets should not be based on prices in intervals prior to t, but the lowest prices among future intervals including the binding interval.*

2. *Cycling costs*, including the shortening of battery lifetimes due, e.g., to deep discharge cycles, have been an underrecognized cost in electricity markets. Battery owner concerns over those costs may account for the fact that most batteries presently operating in the ISO's markets are used to provide regulation rather than energy arbitrage.[14] Consideration of those costs can make a large difference in how batteries would be used in energy

[13]However, if the DEB for an advisory interval in real-time is sought, conceivably an earlier interval that is also being optimized in the same real-time market run could be the source of charging power. Including real-time charging costs in real-time DEBs is a complication that is not envisioned in the proposal, and would in our judgment not be worth the additional computational time involved.

[14] DMM, 2018 Annual Report on Market Issues and Performance, Fig. 1.11, p. 39; DMM, 2019 Annual Report on Market Issues and Performance, Figure 1.19, p. 49.

markets.[15] Unfortunately, the cost is complex, and not a constant $/MWh value. It depends on the battery type and several operating variables, including the cumulative depth of discharge, discharge rate, and immediate past history of discharge. These variables interact in complex ways, although there are some approximations that can be implemented in market software by adding a number of linear variables and constraints for each battery.[16] The ISO proposes that a simple $/MWh value be used as a first approximation; we believe that the more complex representations discussed in the revised straw version of the proposal[17] would not necessarily be an improvement upon that simple assumption while posing computational challenges. More accurate approximations could be considered in the future as computational capabilities improve, and if experience with the simple $/MWh value results in highly suboptimal over- or under-cycling of batteries. (For instance, as the "duck belly" deepens, it may be optimal to cycle batteries twice a day, even given the resulting shortened lifetime.)

In sum, an incremental discharge in a given *t* often results in a deeper cycle, and ultimately a shorter lifetime for the battery. These costs are not considered in the optimization unless they are bid in. *Since cycling costs are not implicitly considered in day-ahead or real-time optimizations, they are a legitimate part of offers and therefore DEBs. They can be included either in DEBs for charging bids, or DEBs for discharge offers in both the IFM and real-time, with appropriate accounting for energy losses.*

3. *Opportunity costs.* If a market run considers all the relevant constraints for a storage resource, and the market's time horizon is far enough in the future to encompass all the likely times when the present energy in the battery would be discharged, then the optimization implicitly weighs opportunity costs when choosing to discharge in a given *t*. It is not necessary to build those costs in the offer in that case.

   But if the time horizon is sufficiently short so that is not the case, then the implicit opportunity cost in the optimization may understate the true opportunity cost. The true cost can arise from retaining energy in storage at the end of the last advisory interval and then selling it later when prices might be higher. Then, as pointed out in Section II, the optimization may discharge too much energy in the short-term, or fail to charge storage sufficiently relative to a solution that considered intervals beyond the time horizon. As that section discusses, solutions to that problem can include placing an explicit value of energy upon the SOC at the end of the last interval considered, or, alternatively, constraining the ending SOC. If the explicit value of energy or constrained SOC at the end of the last advisory interval are close to optimal, then the optimization will automatically consider opportunity costs beyond the time horizon, and it is not necessary to include them explicitly in the storage unit's energy offer.[18] Alternatively, as pointed out in Section II, if there isn't an explicit energy value applied to the ending SOC, then placing the opportunity cost in the offer to sell can be equivalent to a $/MWh value applied to the

[15] Xu, B., Zhao, J., Zheng, T., Litvinov, E. and Kirschen, D.S., 2017. Factoring the cycle aging cost of batteries participating in electricity markets. *IEEE Transactions on Power Systems*, *33*(2), pp.2248-2259.

[16] Ibid.

[17] ESDER 4 Revised Straw Proposal, Section 3.1.3, Oct. 21, 2019, http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf

SOC in the last advisory interval. An attractive strategy might be a mix of specifying a minimum SOC at the time horizon plus an value of energy for SOC levels above that minimum, which would allow less energy to be discharged if real-time prices turn out lower than IFM prices.

In summary, with a sufficiently long time horizon (as is often or usually the case in the day-ahead market) or if an EOH SOC is applied in advisory intervals, *it is not necessary to include opportunity costs explicitly in energy discharge offers, as the optimization automatically and implicitly considers them.* A complex procedure to estimate opportunity costs and calculate DEBs is not necessary. *In real-time when time horizons are short, and if EOH SOCs are not specified, then discharge offers need to include opportunity costs to prevent over-discharge or under-charging of storage if there is a significant probability of higher prices later in the day.*[19]

4. The formula used in the proposal is meant to approximate the incremental cost of discharging energy in *t*, but involves a number of simplifications that mean that the DEBs deviate from the actual incremental cost. As just two examples:
    - One is the "maximum" operator; in some cases, the actual incremental cost is the *minimum* of the recharge cost (plus cycling cost) and opportunity cost. The reason is that the optimization chooses the *cheapest* way to provide the incremental energy for discharge, and if increasing charge at some other time is feasible and less expensive than a feasible reduction in sales at another time, it will choose the former; otherwise, it will choose the latter. (See Example 1 in Appendix 1 to this Opinion). The key is determining what changes in charging or sales are feasible; this changes over the day, so the DEB will also change over the day (as shown in the example).
    - Another simplification in which the opportunity cost is assumed to be the $N^{\text{th}}$ highest price in the day ($N$ being the number of hours of storage); this is not true for real-time markets, as explained above, or even for some hours in the day-ahead market (as shown in Example 2 in Appendix 1).

Further, as pointed out in the next subsection, bidding zero for charging and setting discharge offers equal to cycling costs, subject to a constraint on the EOH SOC for the last interval, will maximize a competitive (price-taking) firm's profits, given that constraint. Assuming no market power, and given that the software correctly represents the battery's SOC, charging, and discharging constraints, making any offer other than cycling cost cannot increase the storage owner's profit.

If the above recommendations were to be followed in constructing the DEB, then Equation 1 in the draft final proposal would be modified according to what we call the **"purist approach"** to DEBs:

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[19] This conclusion assumes that, consistent with the ISO's proposal, that resource owners cannot specify a per unit monetary value of energy to be applied to the ending SOC in the last interval. If our proposal from Section II to allow such values to be applied was implemented, then bidding opportunity costs for discharges would not be necessary.

1. **IFM Market:** the DEB for discharging would only include an estimate of cycling cost, as opportunity costs and charging costs are automatically and implicitly considered in the market optimization, if the market optimization explicitly models SOC and charging/discharging capacity constraints. Higher DEBs that include explicit opportunity or charging costs are not needed to prevent a risk of over-discharge or under-charging in earlier intervals. DEBs for charging bids are zero, as explained in the next subsection. This recommendation assumes that either an appropriate SOC or a $/MWh value for energy in storage is specified for the end of the day, reflecting what the energy would be worth if saved for the following day, or reserved from day-ahead energy schedules for use in balancing intra-hour variations in net load, particularly when the system might otherwise be ramp constrained. (Note that the present ISO proposal does not allow a $/MWh value to be assigned to energy in storage for the end of the day, so the storage owner is obliged to set a EOH SOC for the last hour of the day.)

2. **Real-time Market:** If the storage owner does not specify an EOH SOC for later or the last advisory intervals or an appropriate economic value of energy in storage at the last interval, then too low a DEB risks over-discharge or under-charging, depriving higher price intervals after the time horizon of valuable stored energy. It would then be appropriate to include opportunity costs in discharge offers, and thus in the DEBs for those offers. However, if the storage owner specifies an EOH SOC for the last advisory interval and/or a reservation value for energy in storage at that time, opportunity costs should not be included in DEBs. In either case, charging costs should not be included in DEBs, and DEBs for charging bids are zero.[20]

A "**purist approach**" to constructing charge bids and discharge offers is analogous. Given that the EOH SOC parameter is used to fix the SOC for the optimization's time horizon (or an appropriate value of energy assumed), a profit maximizing price-taking storage facility should offer to buy power at $0/MWh, and offer to discharge at the marginal cost of cycling, without baking the costs of power purchases or foregone opportunities into the bids/offers. As long as the SOC and losses are modelled by the market software, along with the battery's capacity constraints, opportunity and purchase costs will be implicitly and automatically considered in the scheduling algorithm.[21]

[20] One concern with the ISO's previous proposal of an end-of-day SOC parameter was that it might, for example, require aggressive and possibly expensive charging during hours ending (EHs) 23 and 24, or might not even be feasible. A logical means of dealing with that possibility is to allow relaxation of that constraint in the downward direction at a relatively high assumed value of energy. This would be consistent with our proposal to allow value of energy bids for the SOC at the time horizon of the optimization.

[21] It can be shown that not only the "purist" offers and bids will result in the correct (overall system cost minimizing) storage schedule, but that there are also other sets of offers and bids that do so, as long as the market software includes all the storage constraints. For instance, an alternative set of offers/bids could be constructed that yield the same optimal schedule, in which the discharge offers equal the incremental cost (minus epsilon) and charging bids equal the incremental cost of energy (minus epsilon) minus the cycling cost (expressed per unit of charging energy). That is, there are multiple sets of offers and bids that yield the optimal schedule. The easiest one to construct is the "purist" bids. But any other offers/bids in which the hourly offer/bid lies between the "purist" set and the alternative set just described will give the same schedule. (To put it differently, for those intervals in which the storage unit sells in the optimal solution, it can make any offer between the optimal price and the incremental cost of discharge,

However, objections could be raised to this purist approach, which we now discuss.

1. During the day, conditions may change from those anticipated when solving the IFM, and it may become apparent that real-time prices will be well in excess of those calculated in the IFM. Owners of storage may then want to deviate their discharge schedule from the IFM schedule by, for instance, shifting discharges to later in the day. One way to do this is to increase offer prices for discharge in real-time to represent the higher opportunity; however, this is likely to be ineffective if offers are mitigated to DEBs that reflect day-ahead estimates of opportunity costs If DEBs are set based on out of date expectations, mitigated bids may be well below opportunity costs that reflect expectations of real-time prices, and fail to reserve energy for use later when prices are higher. Another (and more effective) way to preserve more energy for later is to set the EOH SOC parameter to a higher MWh value to retain energy. Since the latter option is available to storage resources under the present proposal, this should not be an objection to the purist approach, especially if, as we propose, storage owners are allowed to specify a $/MWh value of energy at which they'd be willing to deviate from the target ending SOC.

2. When submitting offers for the IFM, the storage owner might anticipate tighter conditions than indicated, for instance, by the ISO's load forecast and therefore might anticipate that real-time prices will imply higher opportunity costs than would be estimated by the ISO. Thus, it could be argued, storage should be allowed to include opportunity costs that reflect expectations of real-time prices. A reply to this argument is that if the resource actually believed that real-time prices will be generally higher than IFM prices, the resource can use virtual bids to profit from that expectation (without risking mitigation),[22] and in real-time can impose EOH SOC parameters to defer discharging energy, if optimal.

3. Storage that can flexibly generate in some 5 minute intervals but not others within a given hour have an option value that is not captured in IFM prices. If real-time prices are volatile, the optimal operation might then involve some discharge in many if not most hours (during those real-time intervals with high prices) and reserving some energy for later hours even if IFM prices indicate that those later hours have lower average prices. Consequently, when storage operations are optimized in real-time, hourly MWh discharges will be spread out more than a IFM schedule. Consequently, a storage owner

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and the same schedule will still be optimal. Similarly, a bid to buy charging power, if at least as much as the price but not more than the incremental value will find the same solution to be optimal.)

The proof involves examination of the first order conditions of a problem in which revenue minus cycling cost of storage operations are optimized subject to market prices and physical storage constraints. The shadow price of the storage energy balance (stored energy at the end of interval $t$ = stored energy at the start minus net withdrawals) is the incremental cost for $t$. It can be shown that the optimal schedule for the original problem remains optimal if instead bids and offers are constructed in the manner described because that optimal schedule still satisfies all the first order conditions.

[22]However, virtual demand bids can only take advantage of this situation if real-time prices, averaged over the hour, exceed the IFM price. In contrast, storage has an additional option value if real-time prices are volatile, as storage can limit its discharge to the highest price real-time intervals.

will want to ensure that energy is saved for later intervals, perhaps by bidding in a way that reflects the opportunity cost (including option value) of conserving energy for use later. However, a reply to this point would be that the owner can use the EOH SOC parameters to save energy for later without having to include opportunity costs in discharge offers; if in addition our proposal for a $/MWh energy value to be applied to ending SOC, there would be additional flexibility for additional energy to be held back for its real-time option value only if the day-ahead price does not exceed that value.

4. Based on expectations of different prices in the next day, it might not be optimal to return the battery's SOC at the end of the day to the value that occurred 24 hours earlier (i.e., the storage owner might prefer less or more than a full charge-discharge cycle). In theory, bids to charge and offers to discharge should then reflect opportunity costs for the following day in order to optimally trade off discharges in the two days—unless the storage owner specifies an EOH SOC for the last hour of the first day based upon the owner's assessment of the optimal amount of energy to save for the second day. Which, of course, the owner can do under the proposal, so this is not a major objection either.

5. The purist approach is inconsistent with the CC-DEBE approach to opportunity costs. There, opportunity cost-based components are used to modify the energy, start-up, and/or run hour components of offers in order to provide the operator with maximum flexibility while recognizing the implications for costs beyond the time horizon of the optimization. Our purist proposal in which EOH SOC is used to account for the value of later opportunities to sell energy would be analogous to a resource owner in CC-DEBE specifying the amount of energy to be sold, number of starts to be allowed, or the number of hours to be run for a given market run without giving any flexibility to the operator. A reply to this objection is that giving storage owners flexibility to specify $/MWh energy values for the ending SOC in the last interval of an optimization (as we propose in Section II) would then give flexibility to the ISO that is fully analogous to the flexibility provided by CC-DEBE's treatment of opportunity costs.

6. The restriction of charge bids to zero and discharge offers to cycling costs is highly restrictive, and there may be other cost-based reasons why storage owners would want more flexibility to structure bids and offers as they would like. A reply would be that this could be allowed under ISO rules as long as LMPM is not triggered. If, however, mitigation is imposed, then we would prefer that that the purist DEBs described above be imposed, unless convincing evidence for the existence of these other costs is provided.

In summary, the development of bids and offers, and the estimation of DEBs, would be greatly simplified if it is recognized that optimal charge/discharge schedules that reflect opportunity costs of possible sales after the optimization's time horizon can result from a combination of (i) including only cycling costs in discharge offers and (ii) the resource owner specifying a preferred EOH SOC for hour 24 (in the IFM) or the last advisory interval (in real-time), and/or a $/MWh value for energy in storage at that time. Optimal discharge offers for competitive firms, and their DEBs, just equal estimated cycling costs in that case. A major assumption is that EOH SOC values are not manipulated to exercise market power, which, as we pointed out in Section II, is a risk. This risk might be to a lesser or greater extent be mitigated by allowing EOH SOC to be specified only in the last advisory interval, which will prevent creation of artificial shortage conditions during subsets of intervals. Another assumption is that owners can estimate the ending SOC that will maximize overall profits.[23]

### III.C Other Comments on Storage DEBs

**Charging Bids.** We agree with the proposal and staff comments that DEBs should be specified for bids to charge. This is because the supply provided by storage is not just a function of offers to discharge. In the IFM, for example, even if supply bids are very low (e.g., just cycling costs, as in our purist proposal above), a storage owner can restrict supply by bidding a negative willingness to pay for charging power. The reason for this is that the decision of the IFM to charge and then discharge a battery is a function of the difference between the discharge offer and the charge bid, as well as losses and cycling costs. A general point is that if only discharge offers are mitigated by the LMPM mechanism, then opportunities to exercise some degree of market power by manipulating charge bids and EOH SOC parameters will still remain.

Our understanding is that Equation 1 of the proposal (MAX (Expected charge costs, opportunity costs)*1.1) would be used to set the DEB for charging bids. We propose an alternative. Consistent with our purist proposal, optimal bids for charging energy should be zero in the IFM, as long as a reasonable EOH SOC is specified for hour 24. Similarly, they should be zero in real-time markets, given that a reasonable EOH SOC is provided for the final advisory interval (or close to it). No cycling cost needs to be included in charging bids; assuming that a cost per MWh cycling cost is not unreasonable, then it only needs to be included in discharge offers since charging is always (eventually) followed by an equal discharge later (adjusted for losses). Given the purist values for the charge bid (zero) and discharge offers (cycling cost), together with an EOH SOC parameter for the last interval, then the market software will optimally determine charging and discharging over the time horizon.[24] For a competitive firm, it can be shown that the purist offers/bids will be profit maximizing, given a reasonable EOH SOC or value of energy for the last advisory interval.

**Mitigation of Spreads.** A possible alternative to setting DEBs for discharge offers and charge bids is to apply mitigation for the *spread* between offers and bids, since that spread (adjusted for losses and cycle costs) determines whether storage is used or not. However, there are two problems with this idea. One is that due to the effect of losses, a $60 spread between a $0 bid to charge and $60 offer to sell will be viewed differently by the market software than a $60 spread between a $100 charge bid and a $160 discharge offer. The other is that especially in real-time, but also in the IFM, the optimal solution might not be a complete cycle over the entire time horizon in which the ending SOC is the same as the beginning SOC. In that case, not only the spread

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[23]Accounting for opportunity costs of sales later, including the possible option value associated with taking advantage of real-time price volatility to discharge during just the higher price real-time intervals. As mentioned, if storage was also able to state a $/MWh value of energy for its ending SOC, which is not an element in the ISO's proposal, an optimal strategy might be to put a lower (but not upper) bound on the SOC and a value of energy as well, so that if the market software obtains lower than expected prices for before the time horizon, more energy can be stored for later.

[24] Alternatively, charging costs could be deducted from the cycling bid (corrected for losses), and no cycling costs included in the discharge bid. If losses are accounted for correctly, the same optimal schedule would result. Appendix 2 of this Opinion gives an example.

but the actual levels of bids and offers will affect the ending SOC and thus the amount of energy carried beyond the time horizon. For instance, if we consider a RTPD run in the belly of the duck curve, then a combination of high charge bid and high discharge offer will surely result in full charging of the battery, while a combination of very low charge bid and discharge offer might result in less charging, even if the cycle costs are the same.

**Opportunity Cost Calculations and Extending the Time Horizons of Real-Time Market Optimizations.** The procedure for calculating DEBs proposed for estimating opportunity costs for a particular day starts by rescaling the previous day's IFM prices by the ratio of an index of day-ahead bilateral contract prices for the day in question to the index for the previous day.[25] Then if a storage resource has (say) *N* hours of storage, its opportunity cost in a given hour *t* is estimated as the $N^{th}$ highest hourly price. This assumes one charge-discharge cycle per day, and that foregone opportunities are in the day-ahead, not real-time market; both are not unreasonable approximations for the initial implementation for the day-ahead market, but should be monitored and revised if experience indicates that they are inadequate. For the real-time market, however, errors are likely to be greater for several reasons. One is that real-time prices beyond the time period of the market optimization are uncertain, but on some days may be predicted to be much higher (or lower) than day-ahead prices at the time that real-time markets are run. Another possible source of error is that the $N^{th}$ highest IFM price may occur in an interval before the real-time market in *t*. Under the approximate assumption that the battery will be fully discharged (or nearly so) sometime before the end of the day, a more relevant IFM price might be the *M*th highest hourly price, where *M* is the number of hours of energy in storage at *t*. This assumes no further charging of the battery in the rest of the day prior to any remaining high price periods; of course, this assumption may be incorrect if *t* is in or before the bottom of the duck curve, when charging may be economic. We believe that given the present time horizons of the RTPD and RTD markets it will not be feasible to develop a transparent but more accurate procedure to account for real-time prices or charge/discharge patterns for the rest of the day in determining opportunity costs. In particular, we recognize that it is not presently practical in the ISO markets to predict real-time prices beyond the time horizon for purpose of market power mitigation, which is one of several reasons why we endorse use of the EOH SOC parameter in the last advisory interval together with mitigation of offers to just the cycling cost, as explained above.

A more fundamental approach to dealing with the problem of uncertain opportunity costs in real-time is to extend the time horizon of the real-time markets so that it encompasses all the likely high price periods of the day. This is recognized by some stakeholders. Although the computational, forecasting, and other challenges are likely to be significant, even approximate modeling of advisory intervals much later in the day is likely to provide a more logical basis for operating storage and accounting for opportunity costs.[26] In particular, as we pointed out above, opportunity costs associated with potential discharges prior to the time horizon are automatically and implicitly accounted by the market software, and do not have to be estimated or included in DEBs. The result is that constructing offers and bids and calculating DEBs will be appreciably

[25] Final proposal, Equation 2, p. 26.

[26] Because more distant intervals will have more uncertain forecasts, however, the endogenous calculation of opportunity costs could be more accurate if uncertainty in the later advisory intervals is recognized through multiple deployment scenarios, such as suggested

simplified, storage is likely to be more efficiently used, and customer costs will be decreased. Furthermore, the need to have a minimum charge requirement for storage resources that are supplying RA can be eliminated, if the real-time horizon for operations in mid-day or later is extended to cover the evening peak; the real-time optimization can determine when it is best to charge and discharge energy or to just hold it, as opposed to a highly conservative rule that is imposed because the present real-time market cannot see beyond its limited time horizon.[27] Therefore, although it may not be practical at this time to extend the time horizon of the RTPD and RTD markets, evaluating the potential for such extensions should be made a priority. This is especially true since storage will become more important on time scales of 3-5 hours as evening ramps steepen and the net load peak is moved later into the evening as the result of increased solar penetration.

There are however fundamental limitations to the approach of extending the time horizon which could result in underestimation of opportunity costs. First, if just one net load forecast is used for all advisory forecasts, the impact of possible net load forecast error upon the value of storage will be disregarded. The impacts of underforecasts upon prices (and thus opportunity costs) may be much greater than overforecasts; as a result, using just an expected forecast may underestimate the expected opportunity cost.[28] Second, advisory intervals are unlikely to reproduce the real-time price volatility that creates the option value described above, in which storage can save its discharge energy for the highest price real-time intervals and so earn revenue that is greater on a per MWh basis than the average price. Optimization models tend to produce smoother trajectories of prices than occur in reality either because the intervals are too wide (especially if fifteen-minute price volatility is considerably less than 5 minute volatility) or because load and variable renewable forecasts tend to be smoother than what is realized. As a result of this suppressed volatility, real-time market software with extended time horizons may systematically underestimate opportunity costs. These two limitations provide some justification for allowing

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[27] The Minimum Charge Requirement is no longer part of the ESDER 4 initiative but is instead part of the parallel Resource Adequacy Enhancements initiative (http://www.caiso.com/InitiativeDocuments/FifthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf). In our opinion, we agree with the ISO's position in that initiative (ibid., p. 75) that extending the time horizon is in theory the best way to address the concerns of some stakeholders that the minimum charge requirement will increase costs due to its inflexibility and is an inefficient means of ensuring that storage maximizes its contribution to system adequacy (e.g., "Comments of the California Energy Storage Alliance (CESA) on Energy Storage and Distributed Energy Resources Phase 4", March 16, 2020, http://www.caiso.com/InitiativeDocuments/CESAComments-EnergyStorage-DistributedEnergyResourcesPhase4-SecondRevisedStrawProposal.pdf . Until such an extension is feasible to implement, however, the minimum charge requirement appears to be an effective if perhaps costly and inflexible way to ensure that storage capability is available during evening net load peaks. The MCR can be viewed as equivalent to a mandated EOH SOC (as opposed to the voluntary one in the ESDER 4 initiative), set at a level of full charge prior to the evening peak under the assumption that the opportunity cost of storage in the evening peak exceeds the price of energy in intervals prior to the real-time market's time horizon.

To reiterate, we believe a longer time horizon for the real-time market could be a better way to assess whether this is likely to be true or not for a given day, especially if combined with the Department of Market Monitoring's proposal for a multihour-type flexible ramp constraints in real-time (R. Kurlinski, "Day-ahead market enhancements discussion", CAISO MSC meeting, July 30, 2020, www.caiso.com/Documents/Day-AheadMarketEnhancementsDiscussionDMM-Presentation-July30_2020.pdf). See our Opinion on Flexible Ramping Product Requirements, draft, September 2020, where we discuss DMM's proposal, and recommend that presently proposed improvements to the FRP be implemented and their performance evaluated before detailed consideration of such a proposal.

[28] This would be one reason to consider DMM's proposal for multihour-type FRP constraints, ibid.

opportunity costs in discharge offers. However, the option value component of opportunity costs that potentially arises from these two sources of uncertainty is not considered in the ISO's DEB proposal because of its use of IFM prices. The 1.1 factor in the DEB can be viewed, at least in part, as compensation for the omission of the option value.

**Summary of Recommendations.** In summary, we would prefer a simpler system for offering storage into the ISO markets in which charging bids are zero, discharge offers reflect cycling costs, all SOC and capacity constraints are represented, and owners can specify EOH SOC for the final interval in the optimization (as well as other intervals if desired) and/or an energy value for the final SOC. The ISO could allow offers and bids that deviate from this structure but we would recommend that if local market power mitigation is triggered, then this structure for offers and bids be imposed. As pointed out in Section II, however, the possible use of EOH SOC parameters to exercise market power should be monitored carefully.

## IV. Effective Load Carrying Capability (ELCC) and Demand Response Resources

Resource adequacy (RA) mechanisms are an important part of many power markets, including the CAISO's market. A significant portion of the gross margin (revenue minus variables costs) that resources depend upon to recover capital and fixed operating costs is provided by RA payments. What a particular resource earns from a RA market depends upon the price of capacity, the amount of qualifying capacity the resource provides (also called a capacity credit), and penalties or other adjustments for actual performance of the resource.

The calculation of capacity credit is difficult, especially for non-traditional resources such as variable renewables and demand response. Capacity values can depend strongly on where a resource is located in the system, the resource's use and availability limitations, and the market penetration of that resource type, and its impact on the load shape relative to the mix of other resource types, which is subject to change over time. There can also be a large difference between average credit for a resource type and the marginal credit that an incremental investment will provide. Miscalculated credits can have several distorting effects on markets.[29] If too little credit is given to a particular resource type compared to its actual contribution to system adequacy, there will be too little investment in it, all other things being equal. This can inflate the cost of achieving a given system adequacy standard (such as loss-of-load-probability). System adequacy may also be underestimated, resulting in more reliability than policy makers were targeting. On the other hand, if too much credit is given to a particular resource type, the reverse can happen. Too much investment may be made in that type of resource relative to other types, and the system reliability may be overestimated. Disregarding locational differences could lead to siting resources in the wrong places and lower levels of reliability than intended because resources cannot be used to meet load when needed. Finally, for resource types, like solar, that have high correlations of availability and output among different installations, marginal capacity credits decrease with the amount of capacity that is installed, and awarding RA payments based

[29] In one study of the impact of capacity credit distortions, system cost increases of as much as 6.3% were found for a hypothetical system similar to ERCOT (Bothwell, C., & Hobbs, B. F. (2017). Crediting wind and solar renewables in electricity capacity markets: the effects of alternative definitions upon market efficiency. *The Energy Journal*, *38*(KAPSARC Special Issue)).

on average rather than marginal capacity credits can result in overinvestment in highly correlated facilities, discouragement of diversification, and poorer system performance than anticipated.

The events of last month in the CAISO are a vivid reminder of the importance of accurate characterization of resource reliability over all hours of the year and their contributions to system adequacy. Here we make some general comments about the need for careful assessments of ELCC especially for demand response and other resources that do not fit the traditional thermal generator reliability model. We also offer some specific comments on the E-Three study of demand response contributions to system adequacy that was recently undertaken for the CAISO, and summarized in the ESDER 4 proposal. Our purpose is not to give a detailed technical review of that study, but rather to highlight some of the issues it raises for calculation and use of ELCC in markets.

### IV.A Determining A Resource's Contribution to System Adequacy

ELCC expresses the contribution of a resource, or more generally a set of resources, in units of equivalent MW of either peak load (which is the traditional definition) or a perfectly reliable and flexible resource. To apply ELCC, an adequacy index has to be chosen and a target value specified, such as the traditional 1 day in 10 years loss-of-load reliability standard, or an energy-based metric, such as a target expected unserved energy. The adequacy index is usually calculated by comparing available resources to load in either a Monte Carlo or other chronological simulation or, for pure thermal systems, probabilistic convolution methods. Expected unserved energy, for instance, is the average annual (or other time period) amount of MWh during times when resources are short of load. The target for the index is usually selected by the regulator.

For a given power system consisting of an assumed load distribution and base set of resources, once the index and target are selected, then by one version of the ELCC procedure, the ELCC of a particular resource (call it resource A, say a wind farm that is 300 MW in size) is calculated by defining two power systems that attain that target:

1. A base system with the assumed load distribution and base resources but without resource A, plus a hypothetical perfectly reliable and flexible resource (call it resource B) who capacity is increased or decreased until the target value of the index is met.

2. The base system, augmented with resource A, plus the perfectly reliable/flexible resource B, which is again adjusted until the target is met.

The second will require less of resource B than the first, because the second has the base system plus resource A. For instance, if A is a 400 MW wind farm, and the target Expected Unserved Energy is 0.001% of load, then the second system might require 150 MW less of resource B. Thus, in terms of resource adequacy, the 400 MW farm A, would be equivalent to 150 MW of B, so the ELCC of A is 150 MW. ELCC can also be expressed as a capacity credit, which is the ratio of the ELCC to the nameplate capacity, or 150/400 = 37.5%.[30]

[30]There are many variants of this procedure. The original Garver procedure instead scaled the load distribution up and down in order to maintain the target value of the index (LOLP), and the increase in load (measured in terms of peak) that can be accommodated by resource A was the ELCC (Garver, L. L. (1966). Effective load carrying capability of generating units. *IEEE Transactions on Power Apparatus and Systems*, (8), 910-919).

A simple example of ELCC calculations is provided in Appendix 2, based on simple probability methods. The early implementations ELCC assumed independent generator forced outages, which in turn were assumed to be independent of load and disregarded most operating restrictions such as unit commitment constraints. However, today's ELCC calculations (and adequacy calculations in general) are much more sophisticated, and usually involve chronological simulations of system operations.[31] These methods can consider random outages and repair times, charge and discharge of storage, and correlations of resource availability (for example, a wind farm's correlation with other wind resources, solar resources, and wind).[32] The impact of location can be very important, not only because of the quality of the resource and its correlation with other resources is site dependent, but also because transmission congestion can significantly constrain a resource's contribution to system adequacy. We note though that although ELCC methods have improved, new challenges are arising because of the new mix of variable renewables and storage. As examples, errors in short-term forecasts of availability should be considered in assessing the contribution of resources to adequacy, and the increasing importance of energy constraints means that not only correlations of resource availability and loads within an interval but also correlations over time will become increasingly important.

Operating constraints, grid congestion, location, cumulative investment, presence or absence of storage, correlated availabilities and loads, shifting net load peaks due to high renewable penetration and many other complications mean that simply adding up derated capacity and comparing it to (for instance) peak load plus a target installed reserve margin is likely to significantly distort incentives for investments and even predicted system reliability. Thus, if California's RA structure is going to continue to emphasize *ex ante* estimates of average performance, we strongly encourage the development of improved methods for assessing ELCC, especially of resources whose penetration is anticipated to grow in the market—demand response, variable renewables, and storage. It is very important to have trustworthy estimates for resource classes that are anticipated to provide much or all of the capacity additions in California in the near future, and that have the following challenging characteristics:

- resources whose availability is significantly correlated with resources of the same type, other resources, or load;
- resource classes that encompass a diversity of technologies and implementations that can make generalization difficult, such as demand response; and

[31] Keane, A., Milligan, M., Dent, C.J., Hasche, B., D'Annunzio, C., Dragoon, K., Holttinen, H., Samaan, N., Soder, L. and O'Malley, M., 2010. Capacity value of wind power. *IEEE Transactions on Power Systems*, *26*(2), pp.564-572.; Dent, C. J., R. Sioshansi, J. Reinhart, A. L. Wilson, S. Zachary, M. Lynch, C. Bothwell, and C. Steele. "Capacity value of solar power: Report of the IEEE PES task force on capacity value of solar power." In *2016 International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, pp. 1-7. IEEE, 2016; Zhou, Y., Mancarella, P., & Mutale, J. (2016). Framework for capacity credit assessment of electrical energy storage and demand response. *IET Generation, Transmission & Distribution*, *10*(9), 2267-2276.

[32] They could also in theory incorporate operating restrictions such as energy limits, ramp constraints, and limited start-ups and operating hours (Chen, Z., Wu, L., & Shahidehpour, M. (2014). Effective load carrying capability evaluation of renewable energy via stochastic long-term hourly based SCUC. *IEEE Trans. on Sustainable Energy*, *6*(1), 188-197). However, computational challenges mean that commitment constraints are not generally considered in ELCC studies.

- resources that have significant operating restrictions, such as hybrid storage-renewable installations (which limitations on when charging can take place) or demand response resources with limited numbers of calls per month or season.

Actual contributions to system adequacy should be rewarded, and overall system reliability should be accurately characterized.

### IV.B RA Mechanism Design and ELCC

By theoretical analysis of a static capacity expansion model that incorporates energy and ancillary services markets, as well as a RA market, it is possible to show that for a system consisting of variable renewable resources and thermal resources, appropriate definition of capacity credits can result in capacity, energy, and ancillary services payments that incentivize the supply of capacity for the overall cost-minimizing mix of resources. Each resource should be paid its marginal ELCC times the price of capacity.[33] This result applies even in the presence of offer and price caps that result in a "missing money" problem. In equilibrium, each resource would recover its capital costs from the RA, energy, and ancillary services net revenues.

Of course, a number of other strong assumptions, such as absence of market power, no significant scale economies or lumpiness of investment, no short-term forecast errors, and no significant unit commitment constraints, underlie this conclusion. Nevertheless, the result indicates the possibility of designing efficient RA systems under perfect information, and points out the importance of rewarding marginal capacity contributions. Because those contributions decline, sometimes drastically so, as penetration of a resource class increases, the divergence between average ELCC for a resource class and marginal ELCC can be very large. For instance, as simulated by Keane et al., the <u>average</u> capacity credit of wind in the UK ILEX system declines from 34% at a wind penetration of 8% (measured as the ratio of installed capacity to system peak) to about 20% at 35% penetration.[34] The <u>marginal</u> credit associated with an incremental MW declines from about 25% to 8% over the same range. Thus, at a high penetration, the average capacity credit for wind results in approximately 2.5 times the amount of credit that is economically efficient. Appendix 2 of this Opinion gives a tutorial example that shows calculations for a highly simplistic case; there, as solar penetration rises from 10% of peak load to 70%, the average capacity credit falls from 0.7 to 0.51, and the marginal credit from 0.7 to 0.2.

Because marginal capacity credits for some resource types are well below the average, it is quite possible that the required sum of capacity credits (the sum of ELCC per MW of installed capacity times the amount of installed capacity) to attain the reliability target (in LOLP or unserved energy terms) is much less than the peak system load—in a sense, a negative "unforced" reserve margin. As peculiar as this might appear at first glance, the theoretical analysis just quoted shows that adequate revenues are paid to generation to cover capital costs under the assumptions made. This is because the linearity of the model and assumption of a market equilibrium means

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[33] Bothwell and Hobbs, op. cit.

[34] Op. cit. See also Slide 20 of Z. Ming, V. Venugopal, and A. Olson, "Demand Response ELCC", CAISO ESDER Stakeholder Meeting, May 27, 2020, http://www.caiso.com/InitiativeDocuments/E3Presentation-EnergyStorage-DistributedEnergyResourcesPhase4-May27-2020.pdf,

that payments would be sufficient to cover costs, or supply would not enter. If the total credited capacity falls below the peak load (negative reserve margin), the per MW price of credited capacity would rise, if necessary to ensure revenue adequacy for new entry.[35]

This proposal can be contrasted to approaches to calculating credits for purposes of RA markets reviewed recently by E-three.[36] Most of those approaches deviate from marginal principles, such as "allocate proportionally to first-in ELCC" (which considers the ELCC of a resource calculated assuming it is installed before other resources in a plan) and "vintaging last-ELCC" (where a plant receives, in perpetuity, its marginal ELCC when it came on-line, even if marginal ELCCs for its class decline precipitously in years afterwards). E-three does mention the "last-in ELCC" approach, which is broadly consistent in philosophy with our proposal above for rewarding only marginal ELCC, although its "last-in" approach considers all resources of a given type together when added to the portfolio rather than a marginal ELCC. E-three recommends its own procedure which is a blend of first- and last-in approaches.[37]

There are many practical issues associated with implementing an RA system based on marginal capacity credits, especially if those marginal credits change over time, as they should, as penetration of a given resource grows, the overall mix and load shapes change, and correlations with the availability of other resources and net load evolve. This adds uncertainty to financing of investment, but this is a real uncertainty regarding the value of the resource and should be recognized by financial markets. Also, vintaging capacity credits as described by E-three has significant equity problems as later investments then receive lesser payments per MW than the facility next to them that was built years ago. There are also efficiency problems in that older, less efficient facilities with high maintenance costs will be discouraged from retirement because they receive artificially high capacity credits, which will in turn discourage new investment. Moreover, changes in the resource mix and the temporal load pattern may cause the marginal ELCC of a resource when it first came into service to differ materially from its current value, even if no more resources of that type have come into service.

While an optimally designed ELCC approach could in theory achieve the right mix of resource *investment*, it does little to ensure that such resources actually *perform* as expected and as needed to achieve reliability goals. The ELCC paradigm is part of an approach that rewards an average performance profile, rather than performance during specific reliability events. Markets such as California rely on other incentives, such as short-term energy and ancillary services prices, to incentivize actual performance. In RA and capacity systems where performance incentives are stronger, so that non-performance is penalized and over-performance is significantly rewarded, there is arguably less need for precision in estimating *ex ante* the relative contribution of different resources. With significant performance penalties, resources are more likely to make a realistic assessment of their actual potential contributions to reliability before determining how much

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[35] Of course, if that capacity credit price was charged to load on a per MW of peak load, the result would be over-recovery of costs; this can be handled by simply decreasing the per MW charge assigned to load proportionally.

[36] Ming et al., op. cit..

[37] Ibid., Slide 24 et seq. What we call marginal ELCC they refer to as "incremental last-in" ELCC. However, their procedure uses "average last-in" ELCC which considers all resources of a given type together, as noted.

capacity to sell into a market, regardless of what an *ex ante* statistic such as ELCC predicts their capability to be.

### IV.C. ELCC of DR

DR has only recently become an important resource in the CAISO markets, although it has long been an important tool of California utilities for managing retail loads. The MSC has often expressed its opinion that to achieve economic efficient electricity markets, an active and fully engaged demand-side is essential in which consumption decisions are made in advance and real-time with full awareness of prices and strong economic incentives to react to system conditions. The MSC has stated that demand response programs designs have a tendency to be defined to fill narrow niches, such as peak management, that hobble their potential to shape load, manage costs, and benefit consumers 24 hours per day.[38] We have been disappointed that use of the extensive, and expensive, smart metering infrastructure that has been installed in California has been highly constrained by demand response design and policy. The potential for beneficial demand response may be much greater than currently realized in the CAISO markets,[39] but market design and program improvements appear necessary to harness significantly more of it in the future.

We are generally pleased to see the CAISO's recent initiatives to encourage development of demand response although we have also noted serious concerns with the designs of some programs.[40] Demand response has started to become a presence in California's bulk markets, with a few hundreds of MW of participating demand response in energy and ancillary service markets. This has been a learning phase. In terms of contribution to system adequacy, initial experience, as reported by the Department of Market Monitoring, has indicated that the Load Impact Protocols that the California PUC requires of utilities in its jurisdiction likely overstate the capacity value of demand response.[41] Issues include offering of quantities that are usually well short of net qualifying capacity, offers that are at times, or for durations, that do not realize the full ELCC that was expected, and poorer performance than hoped for (especially of non-utility proxy demand response in the summer of 2018). Careful quantification of actual capacity value of

[38] F.A. Wolak, J. Bushnell, and B.F. Hobbs, "The California ISO's Proxy Demand Resource (PDR) Proposal", Market Surveillance Committee of the California ISO, May 1, 2009, http://www.caiso.com/Documents/MSCFinalOpiniononProxyDemandResource.pdf; Bushnell, J., Hobbs, B. F., & Wolak, F. A. (2009). "When it comes to demand response, is FERC its own worst enemy?" *The Electricity Journal*, *22*(8), 9-18; J. Bushnell, S.M. Harvey, B.F. Hobbs, and S. Stoft, "Opinion on Economic Issues Raised by FERC Order 745, 'Demand Response Compensation in Organized Wholesale Energy Markets'", June 6, 2011, http://www.caiso.com/Documents/FinalSupplementalOpiniononEconomicIssuesRaisedbyFERCOrder745.pdf

[39] A. Faruqui and C. Bourbonnais. "The Transformative Power of Time Varying Rates," Energy Central, March 8, 2019, https://energycentral.com/c/em/transformative-power-time-varying-rates

[40] See California ISO, Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources, Dec. 2013, https://www.caiso.com/Documents/DR-EERoadmap.pdf, and the four ESDER initiatives. The CAISO has also been a leader in various other demand response planning and policy efforts, e.g., California Public Utilities Commission, Final Report of the California Public Utiltieis Commission's Working Group on Load Shift, 2018, https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report.pdf

[41] DMM, 2018 Annual Report on Market Issues and Performance, p. 41 et seq.; DMM, 2019 Annual Report on Market Issues and Performance, Sections 1.2.3 and 11.11.

demand response is important in both the planning and operational time frame for at least three reasons:

- the ISO needs to know what can be expected under conditions of system stress, as events last month have reinforced,
- appropriate incentives for effective demand response development need to be developed, and
- feedback needs to be provided that can be used to improve program and technology designs in order to enhance their actual ELCC.

The E-three study is an impressive attempt to quantify the ELCC of a particularly challenging class of resources—demand response. Because demand response is a very diverse resource class for which generalizations are difficult, and for which experience is not extensive in the CAISO markets, the study made a number of assumptions that can be improved in future work. For instance, correlations with temperature rather than load itself are used to condition availability estimates in the simulation. Furthermore, the large changes in the shape of net load over the last 10 years, and additional changes that are anticipated due to the surge in behind-the-meter solar mean that rather heroic extrapolations of historic trends are likely to be required to model net load patterns and correlations in Monte Carlo analyses. The accuracy of such assumptions will be highly uncertain. In the absence of better estimates, we believe the study is a useful starting point, and we recommend continued work to improve the method and data to inform decisions. We disagree with some of the stakeholder comments that have suggested that this type of analysis is not worthwhile, and that arbitrary capacity credits be awarded without making an effort to quantify and reward the contributions of particular programs.

As discussed above, a major part of any RA program is performance incentives. For practical reasons, the ISO proposes to exempt demand response programs from RAAIM incentives at this time. We agree with the ISO that incentives to bid DR resources' true capability are highly desirable, and we recommend that rewards and penalties based on actual performance during times of system stress relative to credited capacity be developed that would be effective but not onerous for demand response that perform as intended. As the demand response field continues to develop, we are confident that there will be many opportunities for improvement of program efficiency, predictability, and contributions to system reliability.

However, we also recognize that demand response is not monitored and metered within the current demand response framework in the way that supply resources are. For that reason, the MSC has previously advocated that approaches such as "buy your baseline" that provide strong financial incentives for demand response to perform in line with expectations in a way that puts the consumer in the driver's seat regarding forward contracting and short-run response, in terms of providing information and financial incentives to carefully balancing the cost of providing electricity with the benefits of using it.[42]

[42] When demand response programs request consumers to reduce usage, deviations of power use from statistically estimated baselines are often used to estimate the achieved savings, and are the basis for paying consumers for reductions. There are practical challenges to measuring baselines and, in addition, theoretical reasons to believe that consumers have incentives to inflate baselines and thus the savings they are paid for, as well as empirical evidence that this actually happens (Chao, H. P., & DePillis, M. (2013). Incentive effects of paying demand response in

**APPENDIX 1. Examples of Calculations of Marginal Cost of Discharge / Marginal Value of Charge**

This appendix calculates marginal costs of discharge and marginal value of charging for day-ahead and real-time scenarios in situations where storage is binding and not binding. This appendix also illustrates how use of offers and bids other than the "purist" approach does not affect the optimal solution if they satisfy the condition mentioned in Footnote 21.

Consider a battery that can discharge up to 3.9999 MWh if fully charged. (3.9999 rather than 4 is chosen so that the calculated incremental costs are unique.) Its maximum charge and discharge rates are 1 MW, and 20% of the charged energy is lost. The cycling cost is $16 per MWh charged, which is equivalent to $20 per MWh discharged. Given hourly prices $P_t$, the optimal hourly schedule for a day-ahead problem can be found by solving the following problem:

$$\text{MAX} \quad \Sigma_{t=1,\ldots,24} \ \{P_t*(d_t - c_t) - 16*c_t\}$$

Subject to:

$$s_0 = s_{24} = 0$$
$$s_t = s_{t-1} + 0.8c_t - d_t \qquad t=1,\ldots.24$$
$$0 \le s_t \le 4 \qquad t=1,\ldots.23$$
$$0 \le c_t \text{ , } d_t \le 1 \qquad t=1,\ldots.24$$

Where $c_t$ and $d_t$ are charge and discharge quantities (MW) for hour *t*, respectively, and $s_t$ is the MWh state of charge (in discharge equivalents) at the end of hour *t.*

Below we show the incremental costs of discharge for four different cases:

1. Day-ahead 24 hour scheduling, when it is not optimal to fully charge the battery. Here, incremental costs reflect marginal charging plus cycle costs in most hours.
2. Real-time schedule for hours 19-24, when it is not optimal to fully charge the battery. However, because , incremental costs actually reflect opportunity costs rather than charging costs, because all charging took place prior to hour 19, and so represent sunk costs.
3. Day-ahead 24 hour scheduling, when it is optimal to fully charge the battery. Here, incremental costs reflect opportunity costs in at least some hours
4. Real-time schedule for hours 19-24, when it is optimal to fully charge the battery. Opportunity costs are different than in the Day-ahead model. But some hours have

wholesale electricity markets. *Journal of Regulatory Economics*, *43*(3), 265-283., F.A. Wolak, "Residential customer response to real-time pricing: The Anaheim critical peak pricing experiment," Center for the Study of Energy Markets, 2007). An alternative that is incentive compatible and avoids the need to estimate baselines and the risk of manipulation is "buying your baseline" (see citations in Footnote 32). In "buying the baseline", the consumer purchases a forward contract for a certain amount of energy, choosing how much energy and how it is shaped over the day, week, and season. This is the purchased "baseline." Then deviations in hourly energy use from that profile would then pay or be paid the system's real-time price, if actual consumption exceeds or falls below the baseline, respectively. This would provide efficient incentives to reduce or increase consumption depending on system conditions, without exposing all of the consumers' use to the risks of real-time pricing. However, practical implementation questions concerning, for instance, hourly shaping of contracts would need to be addressed.

incremental costs that instead reflect charging costs from hours in which charging doesn't take place.

The non-fully charge cases (Cases 1 and 2) assume the same set of prices (day-ahead = real-time) which are less volatile than the set of prices assumed in the fully charge cases (Cases 3 and 4).

The real-time solutions are obtained by optimizing over periods $t$ 19-24 only in the above model, and fixing the starting storage $s_{18}$ to the level from the day-ahead model minus 0.0001 (so that prices are unique). Thus, it is assumed that t=19 is the binding interval, and that real-time (RTPD) prices within an hour are identical to the day-ahead prices, so we can use hourly intervals to represent the results from the four 15 minute intervals in each hour.

Tables 1 and 2 show the results for the non-fully charged and fully charged cases, respectively. The dual variable for the SOC balance constraint (first constraint above) is $\lambda_t$, and represents the marginal cost of additional discharge in each $t$. Some observations include the following:

1. The marginal value of charging differs from the marginal cost of discharge $\lambda_t$ because of losses and the assignment of cycling costs in the objective to charging. The relationship is: marginal value of value of charging = $0.8\lambda_t - 16$.

2. Day-ahead incremental costs of discharge for Case 1 (non-filled storage) reflect the marginal cost of charging, which is based on the $24/MWh price in t=2. (Note that this is the only time when charging $c_t$ is strictly between 0 and the charging capacity of 1.) That marginal cost is ($23+$16)/0.8 = $48.75/MWh. There are no opportunity costs, because additional discharge in any period will not mean less discharge in some other period.

3. Day-ahead incremental costs of discharge for Case 3 (filled storage) reflect the marginal cost of charging earlier in the day (prior to filling), while reflecting opportunity costs after storage capacity is reached. The cost of charging is tied to the price in $t$=3, because that is the marginal source of energy, while the opportunity cost is the price in $t$=17, which is when the marginal discharge takes place. Note that these marginal costs apply several hours afterwards because the day-ahead market solves all 24 hours simultaneously.

4. Real-time and day-ahead marginal costs of discharge differ, even with essentially the same schedules. For instance, comparing Cases 1 and 2 (non-filled storage), the real-time marginal costs in $t$=19, 20 reflect opportunity costs and are appreciably higher, even though only marginal charging costs determine day-ahead marginal costs. These marginal costs also differ between Cases 3 and 4, but by a smaller amount, since both are based on opportunity costs albeit for different marginal discharge hours.

Table 1. Day-Ahead and Real-Time Schedules and Marginal Costs: Non-Filled Storage (Cases 1,2)

| | Case 1: Day-Ahead, Storage Not Filled | | | | | Case 2: Real-Time t= 19, Storage Not Filled | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Price Pt | Charge $c_t$ | Discharge $d_t$ | SOC $s_t$ | Dual $\lambda_t$ (Marginal Cost $d_t$) | Marginal Value $c_t$ | Charge $c_t$ | Discharge $d_t$ | SOC $s_t$ | Dual $\lambda_t$ (Marginal Cost $d_t$) | Marginal Value $c_t$ |
| | | | 0 | | | | | | | |
| 24.5 | 0 | 0 | 0 | 48.75 | 23 | | | | | |
| 23 | 0.75 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 24 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 25 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 25 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 24.6 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 44.4 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 45 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 46 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 47 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 46 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 24.5 | 0 | 0 | 0.6 | 48.75 | 23 | | | | | |
| 19.5 | 1 | 0 | 1.4 | 48.75 | 23 | | | | | |
| 19.4 | 1 | 0 | 2.2 | 48.75 | 23 | | | | | |
| 19.3 | 1 | 0 | 3 | 48.75 | 23 | | | | | |
| 24.3 | 0 | 0 | 3 | 48.75 | 23 | | | | | |
| 32.3 | 0 | 0 | 3 | 48.75 | 23 | | | | | |
| 52.3 | 0 | 1 | 2 | 48.75 | 23 | | | 1.9999 | | |
| 70.3 | 0 | 1 | 1 | 48.75 | 23 | 0 | 1 | 0.9999 | 62.3 | 33.84 |
| 62.3 | 0 | 1 | 0 | 48.75 | 23 | 0 | 0.9999 | 0 | 62.3 | 33.84 |
| 45.3 | 0 | 0 | 0 | 48.75 | 23 | 0 | 0 | 0 | 45.3 | 20.24 |
| 30.3 | 0 | 0 | 0 | 48.75 | 23 | 0 | 0 | 0 | 30.3 | 8.24 |
| 15.3 | 0 | 0 | 0 | 39.125 | 15.3 | 0 | 0 | 0 | 15.3 | -3.76 |
| 10 | 0 | 0 | 0 | 32.5 | 10 | 0 | 0 | 0 | 10 | -8 |

(Note: $\lambda_t$ and thus marginal costs/values for last four periods are non-unique because of degeneracy)

Table 2. Day-Ahead and Real-Time Schedules and Marginal Costs: Filled Storage (Cases 3,4)

| | | Case 3: Day-Ahead, Storage Filled | | | | | Case 4: Real-Time t= 19, Storage Not Filled | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| t | Price Pt | Charge $c_t$ | Discharge $d_t$ | SOC $s_t$ | Dual $\lambda_t$ (Marginal Cost $d_t$) | Marginal Value $c_t$ | Charge $c_t$ | Discharge $d_t$ | SOC $s_t$ | Dual $\lambda_t$ (Marginal Cost $d_t$) | Marginal Value $c_t$ |
| 0 | | | | 0 | | | | | | | |
| 1 | 24.5 | 0 | 0 | 0 | 50.625 | 24.5 | | | | | |
| 2 | 23 | 1 | 0 | 0.8 | 50 | 24 | | | | | |
| 3 | 24 | 0.9999 | 0 | 1.5999 | 50 | 24 | | | | | |
| 4 | 25 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 5 | 25 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 6 | 24.6 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 7 | 44.4 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 8 | 45 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 9 | 46 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 10 | 47 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 11 | 46 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 12 | 24.5 | 0 | 0 | 1.5999 | 50 | 24 | | | | | |
| 13 | 19.5 | 1 | 0 | 2.3999 | 50 | 24 | | | | | |
| 14 | 19.4 | 1 | 0 | 3.1999 | 50 | 24 | | | | | |
| 15 | 19.3 | 1 | 0 | 3.9999 | 50 | 24 | | | | | |
| 16 | 24.3 | 0 | 0 | 3.9999 | 50 | 24 | | | | | |
| 17 | 62.2 | 0 | 0.9999 | 3 | 62.2 | 33.76 | | | | | |
| 18 | 80.3 | 0 | 1 | 2 | 62.2 | 33.76 | | | 1.9999 | | |
| 19 | 73.3 | 0 | 1 | 1 | 62.2 | 33.76 | 0 | 1 | 0.9999 | 65 | 36 |
| 20 | 65 | 0 | 1 | 0 | 62.2 | 33.76 | 0 | 0.9999 | 0 | 65 | 36 |
| 21 | 45.3 | 0 | 0 | 0 | 62.2 | 33.76 | 0 | 0 | 0 | 45.3 | 20.24 |
| 22 | 30.3 | 0 | 0 | 0 | 57.875 | 30.3 | 0 | 0 | 0 | 30.3 | 8.24 |
| 23 | 15.3 | 0 | 0 | 0 | 39.125 | 15.3 | 0 | 0 | 0 | 15.3 | -3.76 |
| 24 | 10 | 0 | 0 | 0 | 32.5 | 10 | 0 | 0 | 0 | 10 | -8 |

(Note: $\lambda_t$ and thus marginal costs/values for last four periods are non-unique because of degeneracy)

Finally, in Footnote 21, above, some sufficient conditions for bids/offers other than the "purist" bids to also yield the optimal storage charge/discharge schedule were described. Consider the hours in which discharge is at its maximum (1 MW); the storage unit can offer at least its incremental cost but less than the price, and be assured of being taken. (For instance, 17, 7, and 1.5 \$/MWh in Case 3 for $t$= 18,19,20; when added to implicit opportunity costs in the optimization, these offers are less than the price, and so are accepted, yielding the optimal schedule shown in Table 2.) Similarly, consider the hours in which charging is at its maximum ($t$=2,13,14,15); bids of \$0.5/MWh for $t$=2 and \$4/MWh for $t$=13,14,15, like the zero bids in the "purist" case, result in full discharge at those times.

Another set of bids that results in the same dispatch are the charging bids that equal the original SOC dual variable (that were derived based on the purist bids/offers) in each $t$ minus the \$16 cycling cost, and discharge bids equaling the original SOC shadow price. This was numerically tested against the day-ahead case in Table 1, using the shadow prices from column 6 of that table. Thus, this confirms that DEBs don't need to be based on the "purist" model to result in efficient dispatch; however, the purist model is arguably simpler to apply.

**APPENDIX 2: ELCC Tutorial Example**

Consider a system with a 10 GW peak load and 7.2 GW of average demand, in which R1, R2, R3, and a perfectly reliable and dispatchable R4 can be used to meet demand. The following table shows three load levels and the fraction of the year that each is assumed to occur in, along with the availability of each resource in each period.

The base system meets the 10 GW load with 2 GW of R1, 2 GW of R2, 1 GW of R3, and 6.994 GW amount of R4. Its expected unserved energy is 0.072 GW, or 1% of load. The calculation of total EUE is as follows:

= 0.5*0GW + 0.35*0.216 GW + 0.15*0 GW,

where 0.216 GW of unserved load in the peak period is a result of load being 10 GW and available capacity being 9.794 GW, calculated thus:

= 0.7*2 GW + 0.2*2 GW + 1*1 GW + 1*6.994 GW.

Table 3. Data for Simple ELCC Case Study

| Period | Proba-bility | Load (GW) | Availability of Resource by Load Period | | | | Total Avail. Capacity GW, Base | Base Unserved Energy GW |
|---|---|---|---|---|---|---|---|---|
| | | | R1 | R2 | R3 | R4 | | |
| Offpeak | 0.5 | 5 | 0 | 0.4 | 0 | 1 | 7.795 | 0 |
| Peak | 0.35 | 10 | 0.7 | 0.2 | 1 | 1 | 9.795 | 0.206 |
| Shoulder | 0.15 | 8 | 0.2 | 0.4 | 0.5 | 1 | 8.695 | 0 |
| Base System Capacity (GW): | | | 2 | 2 | 1 | 6.994 | Total EUE (GW): | 0.072 |

The following table shows a number of scenarios, all with expected unserved energy of 0.072 GW. Comparing different solutions with different amounts of R1, R2, or R3 allows us to calculate average ELCC (relative zero GW of a given resource) and incremental ELCC (the change in R4/1 GW change in the given resource). For two of the three resources, there are strong diminishing returns, in which the incremental ELCC decreases with increased penetration. .

Table 4: Reliability calculations for alternative generation mix cases, showing calculation of incremental and average ELCC for resources R1, R2, and R3

| Scenario | R1 GW | R2 GW | R3 GW | R4 GW | Expected Unserved Energy | Incremen-tal ELCC | Avg. ELCC rel-ative to zero GW |
|---|---|---|---|---|---|---|---|
| R1 cases: | - | - | - | - | - | - | - |
| | 0 | 2 | 1 | 8.394 | 0.072 | | |
| | 1 | 2 | 1 | 7.694 | 0.072 | 0.70 | 0.7 |
| Base | 2 | 2 | 1 | 6.994 | 0.072 | 0.70 | 0.70 |
| | 3 | 2 | 1 | 6.294 | 0.072 | 0.70 | 0.70 |
| | 4 | 2 | 1 | 5.686 | 0.072 | 0.61 | 0.68 |
| | 5 | 2 | 1 | 5.220 | 0.072 | 0.47 | 0.63 |
| | 6 | 2 | 1 | 5.020 | 0.072 | 0.20 | 0.56 |
| | 7 | 2 | 1 | 4.820 | 0.072 | 0.20 | 0.51 |
| R2 cases: | | | | | | | |
| | 2 | 0 | 1 | 7.394 | 0.072 | | |
| | 2 | 1 | 1 | 7.194 | 0.072 | 0.2 | 0.20 |
| Base | 2 | 2 | 1 | 6.994 | 0.072 | 0.20 | 0.20 |
| | 2 | 3 | 1 | 6.794 | 0.072 | 0.20 | 0.20 |
| R3 cases: | | | | | | | |
| | 2 | 2 | 0 | 7.99 | 0.072 | | |
| Base | 2 | 2 | 1 | 6.99 | 0.072 | 1.00 | 1.00 |
| | 2 | 2 | 2 | 5.99 | 0.072 | 1.00 | 1.00 |
| | 2 | 2 | 3 | 5.09 | 0.072 | 0.91 | 0.97 |
| | 2 | 2 | 4 | 4.32 | 0.072 | 0.77 | 0.92 |
| | 2 | 2 | 5 | 4.11 | 0.072 | 0.21 | 0.78 |
| | 2 | 2 | 6 | 4.06 | 0.072 | 0.06 | 0.66 |