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Integration of Hybrids into Wholesale Power Markets

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Acronyms and Abbreviations

ACC	Aggregate Capability Constraint
AESO	Alberta Electric System Operator
AS	Ancillary Service
ATRR	Alternative Technology Regulation Resource
BPS	Bulk Power System
BSF	Binary Storage Facility
CAISO	California Independent System Operator
CSF	Continuous Storage Facility
CSR	Co-located Storage Resource
DA	Day-Ahead
DAM	Day-Ahead Market
DARD	Dispatchable Asset Related Demand
DASCUC	Day-Ahead Security-Constrained Unit Commitment
DERA	Distributed Energy Resource Aggregation
DIR	Dispatchable Intermittent Resource
DNE	Do-Not-Exceed
DPV	Distributed Photovoltaic
DVER	Dispatchable Variable Energy Resource
ECC	Enhanced Combined Cycle
ED	Economic Dispatch
EIR	Eligible Intermittent Resource
ELCC	Effective Load Carrying Capability
ELR	Energy Limited Resource
EMS	Energy Management System
ERCOT	Electric Reliability Council of Texas
ESF	Electric Storage Facility
ESR	Electric Storage Resource
FERC	Federal Energy Regulatory Commission
GT	Gas Turbine
HB	Hybrid Balance
HSL	High Sustained Limit
HSMR	Hybrid Storage Market Resource
HSR	Hybrid Storage Resource
IC	Internal Combustion Engine
IESO	Independent Electricity System Operator
IPR	Intermittent Power Resource
IRA	Inflation Reduction Act
ISO	Independent System Operator
ISO-NE	ISO New England

ITC	Investment Tax Credit
LBW	Land-Based Wind
LESR	Limited Energy Storage Resource
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
MSR	Market Storage Resource
NGR	Non-Generator Resource
NYISO	New York Independent System Operator
OSW	Offshore Wind
PJM	PJM Interconnection
POI	Point of Interconnection
PSO	Power System Optimizer
PSH	Pumped Storage Hydropower
PV	Photovoltaic
RA	Resource Adequacy
RT	Real Time
RTM	Real-Time Market
RTO	Regional Transmission Organization
RTED	Real-Time Economic Dispatch
RTSCUC	Real-Time Security-Constrained Unit Commitment
RTUC	Real-Time Unit Commitment
RUC	Reliability Unit Commitment
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SER	Stored Energy Resource
SF	Storage Follow
SoC	State of Charge
SoCM	State of Charge Management
SOR	Settlement-Only Resource
SPP	Southwest Power Pool
UC	Unit Commitment
UPV	Utility-Scale PV
VER	Variable Energy Resource

Nomenclature

Indices and Sets

$ESR \in G$	Set of electric storage resources; index of electric storage resources esr.
G	Set of resources; index of all resources g.
$HYB \in G$	Set of hybrid storage resources; index of hybrid storage resources hyb.
$LINE$	Set of transmission line constraints; index of transmission constraints $line$.
R^+	Set of upward reserve categories $\{REG^+, SPIN, SUPP\}$; index of upward reserve categories r^+, including regulation up reserve (REG^+), spinning reserve $(SPIN)$, and supplemental reserve $(SUPP)$.
R^-	Set of downward reserve categories $\{REG^-\}$; index of downward reserve categories r^-, including regulation down reserve (REG^-).
T	Set of time periods; index of time intervals t.
$VER \in G$	Set of variable energy resources; index of variable energy resources ver.

Parameters

$\underline{F}_{line,t}$	Flow lower bound (MW); transmission line constraint $line$, time t.
$\overline{F}_{line,t}$	Flow upper bound (MW); transmission line constraint $line$, time t.
$MaxC_{esr}$	Maximum charge limit (or maximum load, MW); electric storage resource esr.
$MaxC_{hyb,t}$	Maximum charge limit (or maximum load, MW); hybrid storage resource hyb, time t.
$MaxD_{esr}$	Maximum discharge limit (or upper operating limit, MW); electric storage resource esr.
$MaxD_{hyb,t}$	Maximum discharge limit (or upper operating limit, MW); hybrid storage resource hyb, time t.
P_g^{max}	Maximum power output limit (MW); resource g.
$P_{ver}^{forecast}$	Power forecast (MW); variable energy resources ver.
$R_g^{r\%}$	Reserve requirement as a percentage of maximum power output limit set aside for specific reserve type (%); percentage of maximum power output limit for reserve category r^+ or r^-, resource g.
SOC_{esr}^{max}	Maximum SoC limit (MWh); electric storage resource esr.
SOC_{esr}^{min}	Minimum SoC limit (MWh); electric storage resource esr.
$SSOC_{esr}$	Initial or beginning SoC level (MWh); electric storage resource esr.
$TSOC_{esr}$	Final or target (end of horizon) SoC level (MWh); electric storage resource esr.
η_{esr}^c	Charging efficiency; electric storage resource esr.
η_{esr}^d	Discharging efficiency; electric storage resource esr.
$\kappa_{esr}^{r^+}$	Duration requirement (minutes); upward reserve category r^+, electric storage resource esr.
$\kappa_{esr}^{r^-}$	Duration requirement (minutes); downward reserve category r^-, electric storage resource esr.

Decision Variables

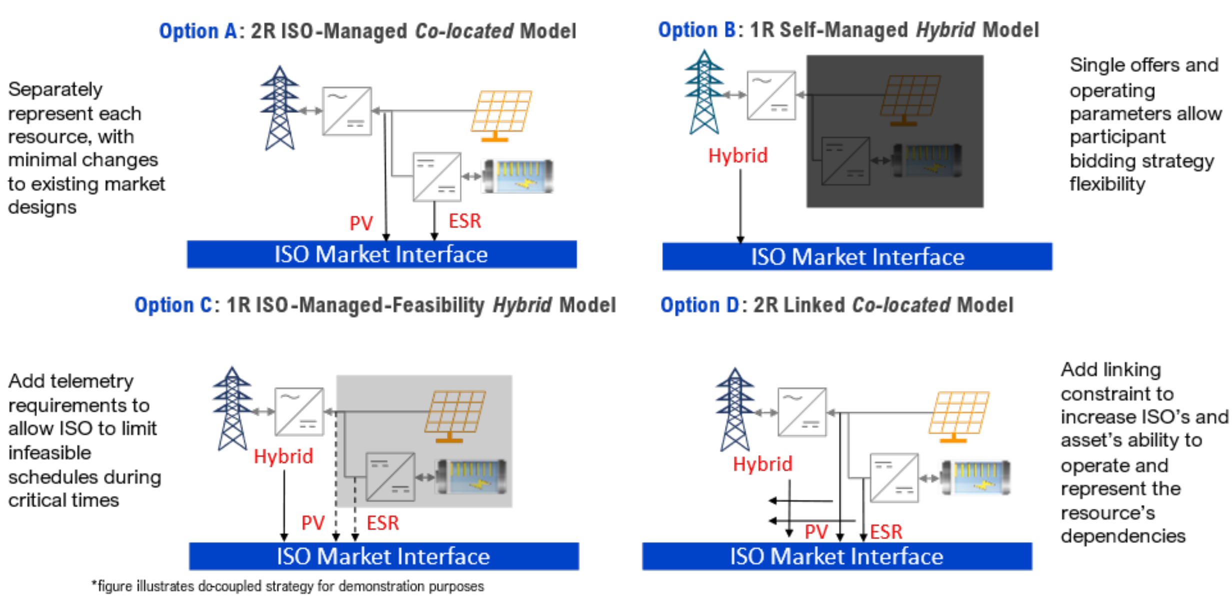
$P_{g,t}$	Scheduled generation (MW); resource g, time t.
$P^{c}_{esr,t}$	Scheduled charge (load, MW); electric storage resource esr, time t.
$P^{d}_{esr,t}$	Scheduled discharge (generation, MW); electric storage resource esr, time t.
$P^{c}_{hyb,t}$	Scheduled charge (load, MW); hybrid storage resource hyb, time t.
$P^{d}_{hyb,t}$	Scheduled discharge (generation, MW); hybrid storage resource hyb, time t.
$R^{r^+}_{g,t}$	Scheduled reserve (MW); upward reserve category r^+, resource g, time t.
$R^{r^-}_{g,t}$	Scheduled reserve (MW); downward reserve category r^-, resource g, time t.
$R^{reg^+}_{g,t}$	Scheduled regulation up reserve (MW); resource g, time t.
$R^{reg^-}_{g,t}$	Scheduled regulation down reserve (MW); resource g, time t.
$R^{spin}_{g,t}$	Scheduled spinning reserve (MW); resource g, time t.
$R^{supp}_{g,t}$	Scheduled supplemental reserve (MW); resource g, time t.
$SOC_{esr,t}$	State of charge level at the end of each time period (MWh); electric storage resource esr, time t.
$SOC_{esr,1}$	State of charge level at the end of the first interval of the optimization horizon (MWh); electric storage resource esr, time 1.
$SOC_{esr,end}$	State of charge level at the end of the last interval of the optimization horizon (MWh); electric storage resource esr, time end.

Executive Summary

This study utilized advanced modeling capabilities to conduct simulations evaluating the differences between various market participation options (or participation models) for utility-scale hybrid storage resources – that is, those that include storage and a separate technology and are behind the same point of interconnection. For the purposes of this study, the second technology was considered to be a variable renewable resource such as wind or solar power. The study evaluated the implications of different levels of these resources on an example system (using the New York State Control Area) to quantify economic and reliability metrics. It focused on participation of these resources in day-ahead energy markets, with a real-time balancing mechanism to ensure that the impact of forecast errors from load or variable energy resources were realistically captured in the metrics. Two primary participation options are being explored in market regions for these resources, and these two were key to the study scenarios:

- **Integrated hybrid resource model (1R):** Market participants provide a set of paired price/quantity offers to the market operator for each market interval and structure those offers to maximize profit while attempting to maintain a feasible schedule.
- **Separate co-located resource model (2R):** Market participants may or may not provide a single price/quantity offer to the market operator for each market interval but will submit information such as renewable resource forecasts and storage state-of-charge information and telemetry so the market clearing solution will optimize the resource to minimize costs across the system.

Additional participation options can be considered, depending on which data from the hybrid or the individual resources are used and how they are used.



We emphasize the use of just one offer strategy for the 1R participation option within this study, as described in Section 3.3. Other strategies are used in practice with traders that can adapt and make changes. This creates some limitations to the comparisons, as described under "Modeling Difficulties" below. The following are the study's primary conclusions:

- **Economic Efficiency**

  > - The 2R model generally provides greater cost savings.
  > - However, differences in efficiency across the participation models are not found to be significant in these case studies.

  Granular models including the 2R participation option provide greater savings in system operating costs. These cost savings were observed in these case studies but were found to be minor and less than anticipated.

  - The magnitude of savings for the 2R model is contingent upon the system conditions under consideration, magnitude of forecast errors, resource mix, fuel costs, and location of the hybrid facilities.
  - The 2R participation option results in efficient scheduling of traditional resources (such as combined cycle plants) that require day-ahead start-up notification; consequently, leading to lesser reliance on the more expensive resources (such as gas turbines [GTs] and internal combustion engines [ICs]) in real time.
  - Explicit consideration of state of charge (SoC) within market clearing software more efficiently operates the hybrid storage facilities under the 2R options.
  - The dependence of the hybrid facilities on the developed bidding strategies in the day-ahead market under the 1R option results in infeasible day-ahead hybrid resource schedules in real time. This leads to increased reliance on more expensive quick-start generation resources (such as GTs and ICs) that are turned on to replace the energy that is not available from the hybrid facilities in real time to ensure demand is met.

- **System Reliability**

  > - No measurable impacts were observed in any of these cases.
  > - Sufficient quick-start capability was able to manage infeasible SoC or variable energy resource forecast error.

  For the system and scenarios analyzed in this case study, no measurable instances of power imbalances or reserve shortages were observed in real time under either of the hybrid resource participation options at their stipulated levels.

  - In alternative cases featuring dissimilar resource mixes, such as a scenario characterized by restricted quick-start or ramping capabilities, limited transmission capacity, or more significant integration of hybrid and renewable energy resources, more adverse reliability outcomes may be observed.
  - In the case studies performed in this report, sufficient quick-start capability was able to cover any infeasible storage schedules. Lack of quick-start resources or insufficient reserve requirements in the future could potentially lead to reliability issues when offers lead to infeasible schedules due to forecast errors and SoC limitations.

- **Asset Profits and Incentives**

> - The 2R model provides greater short-run profits compared to the 1R option.

It was observed that granular models including the 2R participation model led to greater short-run profits. This is primarily due to the 2R scenarios having the following:

- Fewer buyback purchases in the real-time market when compared to the 1R option. The 1R option has an increased likelihood of not being able to provide what was cleared in the day-ahead market in real time, due to the bidding strategies and absence of explicit SoC consideration in the market clearing software used in the day-ahead horizon.
- Greater revenues from the day-ahead market when compared to the 1R option due to the economics of the developed bidding strategies that result in a lower utilization of hybrid resources based on the simulation period under consideration.

- **Hybrid Resource Capability to Follow Different Real-Time Operational Strategies**

> - Greater occurrences of an inability to follow a day-ahead schedule were observed for 1R.

The 1R participation option observes more occurrences where the hybrid storage resources cannot meet their real-time schedules. This is because it is more likely for the schedules to exceed the minimum or maximum storage SoC limits.

- Although explicit offers in the real-time market are expected to become more advanced in practice, the simulations suggest that it may not always be beneficial for hybrid storage facilities to align their real-time schedules with the day-ahead schedule for each hour of the day when other conditions change. This is especially true when there is a risk of imbalances due to inaccuracies in the forecasts of the renewable energy. Balancing the hybrid resource schedule solely for the current interval could impede its ability to meet its day-ahead schedule in a later interval of the day. This may lead to a reliability issue or greater costs for the latter time period.

- **Load Payments**

> - These are dependent on cleared energy awards for the hybrid facilities; they can differ considerably based on the submitted bid strategies or the explicit SoC consideration.

Load payments through locational marginal price outcomes are dependent on the cleared energy awards for the hybrid storage facilities. This can differ based on the bidding strategies or explicit SoC consideration as the cleared awards impact prices.

- Since the day-ahead load is much larger than the real-time deviations from day-ahead load, any small difference in day-ahead market clearing prices between different case scenarios can bring about major differences between the day-ahead load payments. That then impacts the two-settlement load payments more significantly than real-time load payments.

- If the cleared day-ahead hybrid resource schedules are higher for the 1R cases with the developed bidding strategies, that can result in flatter day-ahead prices as storage naturally arbitrages and flattens prices. Consequently, the day-ahead load payments can be lower, which then reduces the two-settlement load payments.

- **Computational Efficiency**

> - Using the 2R model with increasing numbers of hybrids adds greater computational complexity and solve time.

Granular models including the 2R participation model tend to provide theoretical efficiency gains, but they also add computational complexity to the market clearing software. This was observed through greater day-ahead solve times compared to the 1R participation model. This is due to explicit consideration of SoC management that requires explicit time-coupling in the modeling.

- In addition, the day-ahead solve times for cases where grid charging was prohibited are greater than the case where grid charging was allowed for all options.
- Although the 2R participation model may be potentially advantageous for both the asset owner and the market operator, they may be too computationally intensive to enable with greater integration of these technologies without additional software or hardware improvements.

- **Modeling Difficulties**

> - It is difficult to represent the "human in the loop" and advanced strategies. Both models may show better performance with human traders.

The models in these case studies are difficult to represent due to the "*human in the loop*" that is absent but where in practice changes offer behavior based on intuition and observation. While the offer strategies were generally considered state of the art for these studies, they cannot match a set of educated staff changing behavior or altering strategies computed by software. In this case, some of the 1R cases may be considered somewhat conservative and can perform better in practice. Some empirical evidence with greater participation of both options in practice can help substantiate these results as these resources begin to play a larger role in markets.

In general, this analysis confirms the current advantages of the separate co-located resource model (2R) over the integrated hybrid resource model (1R) under the current set of resources and wholesale market practices. This appears to be confirmed in the real world where most "hybrid" resources are electing to use the co-located 2R resource model and some ISOs/RTOs do not yet offer a 1R resource model. However, it is unclear whether the preference for 2R over 1R will continue into a future with changes in resource mix, market design, and computational complexity. This may be further complicated by more complex aggregated resources, such as those that include more than two technologies, are in greater numbers but smaller in size, and have additional unique characteristics that are challenging to capture within the market clearing models.

1. Project Overview

With growing commercial activity around utility-scale hybrid storage projects in the Unites States, independent system operators (ISOs) and regional transmission organizations (RTOs) are faced with making decisions on how to represent such emerging technology resources in the market clearing software through the definition of hybrid resource participation models. System operators are facing increasing uncertainties around efficient and reliable ways to operate these resources given the ambiguity around their impacts, particularly when high levels of hybrid resources are present.

This study aimed to evaluate and compare the performance implications of different hybrid resource participation models in a realistic wholesale electricity market setting with significant deployment of hybrid resources, and to provide the industry with metrics that quantify the advantages and disadvantages of different participation options using realistic electricity market simulations. The different participation models were compared in terms of the impact to reliability of the overall system, the ability of the market to access the full capabilities of hybrid resources as measured by the economic efficiency, and asset profitability. The study also aimed to provide industry recommendations for further examination.

1.1 Participation Model Background

Resource participation models are crucial to enable an increased participation of emerging technologies such as hybrid resources in RTO/ISO organized markets. This study explored the market participation models for utility-scale hybrid storage projects in the United States, with a focus on solar–battery and wind–battery hybrids. Participation models include the tariff, business, and market software features to enable the technology to participate in energy, ancillary services, and capacity markets. Participation models may be defined as the set of market clearing software and tariff provisions required to represent unique physical and operational characteristics of the resource under consideration, or the way the resource interfaces with the wholesale electricity market. They outline how the capabilities or constraints of the resources are represented in the market clearing software and what parameters the resource owner can set via bids or other technical parameters.

Generally, the design of participation models should be such that it allows for the greatest flexibility in participation options where possible, while noting the different perspectives of different market participants and stakeholders who may prefer different models. In the context of hybrid storage resources, some may prefer the single integrated resource modeling option, some the two separate resources modeling option, and others yet a third option, while some may switch to different options throughout the lifecycle of the asset. However, all of this is subject to reliability and the changing impact when large amounts and multiple configurations of these emerging technologies integrate into the grid (i.e., if one option may lead to adverse reliability impacts, the ISO/RTO needs to factor that into the decision-making). It is also subject to costs of implementation since making market design and market clearing software changes are not cheap, and in some instances may impact computational solve time (i.e., one option may be advantageous for both the asset owner and the ISO/RTO but may be too expensive or computationally intensive to enable). Granular models tend to provide theoretical efficiency gains, but they also add complexity to the market clearing software, and they may not be desired by all participants. It is important also to consider the regional differences in systems, existing priorities, and market designs when introducing a participation model.

In many cases, the discussions on hybrid resource participation models are related to the need to define stand-alone electric storage resource (ESR) participation models, as per the Federal Energy Regulatory Commission's (FERC) Order No. 841 (FERC 2018), and distributed energy resource aggregation (DERA) participation models in lieu of FERC Order No. 2222 (FERC 2020). Some discussions have also suggested developing a "universal" participation model as an alternative – one parameterized resource model, i.e., an idealized model for a highly flexible generator or load resource (Ahlstrom 2018). The market participation options for the two components of hybrid projects, i.e., variable energy resource (VER) and ESR, have already been mostly defined. Understanding how these individual technologies independently participate in electricity markets informs potential participation models for hybrid resources. Usually, wind and solar generation forecasts are used for the day-ahead and real-time scheduling time frames. Wind and solar resources are mostly scheduled at their forecasted generation amounts by the market auction models, given their $0/MWh or negative energy offers, except in instances when transmission congestion or very low load and minimum generation constraints of other resources require that VER be curtailed or dispatched down. Alternatively, ESRs may submit bids/offers from their maximum charge capacity to their maximum discharge capacity, but their economic dispatch schedule may be limited by the amount of energy they have to provide, as indicated by their state of charge (SoC) in the current market interval. Scheduling a hybrid storage resource may require appropriate consideration of both VER forecasts and the SoC of ESRs. However, the choice of the participation model in essence dictates whether and how the responsibility of adequate consideration of such unique physical and operating characteristics falls on the hybrid project developer or the system operator.

Participation models were a key point of discussion at the FERC's technical conference on hybrids resources. Attendees deliberated the technical and market issues prompted by growing interest in hybrid resources. Resource participation models are crucial to enable an increased participation of emerging technologies such as hybrids in RTO/ISO organized markets. However, very limited objective, independent analysis is available to guide these discussions. In particular, the implications of selecting different participation models, especially in systems expecting widespread adoption of hybrid resources, is not adequately comprehended in terms of crucial metrics like reliability and economic efficiency. This is especially true given the ongoing large-scale deployment of hybrid resources.

This study examined how nascent participation models impact dispatch and revenue of hybrid battery projects, along with the implications for overall system reliability and economic efficiency. The detailed analysis explored how assumptions about hybrid resource bidding strategies and who has what information affect the relative performance of different participation models. Assumptions about bidding strategies and information available to participants were developed through discussions and collaboration with external technical advisors from several organizations, including ISOs, RTOs, utilities, and project developers. The report is meant to inform different stakeholders—including market participants, market operators, analysts, regulators, and policymakers—who are seeking to understand implications of alternate market participation options for hybrid storage projects and better integrate them into wholesale electricity markets.

2. Electricity Market Participation Modeling Options

It is important to review the state of the art of how each individual resource component of a hybrid resource is operated and interfaced within the electricity market to better understand the challenges with hybrid resources, the extension of existing models to the proposed hybrid resource participation models, and the potential options for integrating such emerging resources into market clearing. Therefore, before diving into the details of the proposed specific hybrid resource participation models, this subsection first describes the existing participation models for both stand-alone VERs and stand-alone ESRs in electricity market clearing software.

2.1 Stand-alone Variable Energy Resource Electricity Market Participation

The level of participation of VERs in energy, ancillary services, and capacity markets differs across different products and regions. The difference between VERs and conventional technologies is that VERs have an upper power capacity limit (megawatts, MW) that differs through time, and that limit is not known with perfect accuracy in advance. Those limits can be better predicted with advanced forecasts provided by outside vendors using meteorological and statistical methods. Outside of this characteristic, modern VER, which consist as collections of variable speed wind turbines and modern photovoltaic (PV) cells with smart inverters and plant level controllers, can be quite flexible. They can be operated between zero and that upper limit at fast response rates, without any variable energy costs (excepting very small operation and maintenance costs) and no commitment costs nor non-operable regions. However, the changing upper limit does require a different operation to ensure market efficiency and reliability. Hence, their forecasts are very important for market participation.

Traditional resources have an upper operating limit (MW) that is constant and known beforehand unless the resource is forced out. ESRs have an upper operating (MW) limit that is constant as well; its upper energy (megawatt-hours, MWh) limit is what impacts dispatch. However, modern VERs are flexible and can be operated between zero and the upper limit with fast response times and at zero cost.

In the day-ahead market (DAM), VERs can bid any offer with any upper limit for each hour. Since the DAM is financial, ISOs do not necessarily have restrictions on these offers and usually do not validate the offers with forecasts. Additionally, VERs normally do not have an obligation to offer, or do at low power levels, even while many other technologies that participate in capacity markets or through resource adequacy constructs do have such an obligation. In the day-ahead reliability unit commitment (RUC) process that is conducted following the DAM (in one ISO these processes are iterated, and in some others, it is proposed to be integrated), the ISO seeks to make a commitment plan to meet the anticipated real-time system conditions. The day-ahead RUC process ignores financial bidding behavior (e.g., virtual bidding), uses its own forecasts of system conditions, and ensures that resources that require day-ahead commitments due to lead times are given notice for commitment when they are needed to meet the ISO’s anticipated real-time conditions for the following day. Virtual bids and offers are ignored, load bids are replaced by ISO load forecasts, and only commitment costs are considered.

VER offers are replaced with ISO VER forecasts. Therefore, if VERs offer quantities that are significantly higher than their forecasted output, the ISO can commit resources to make up for that energy.

In the real-time market (RTM), VERs submit offer costs that reflect their willingness to operate. ISOs also have real-time forecasts for VERs that can be used, which are typically based on persistence for wind, or persistence plus known ramp for solar. Most ISOs use real-time VER forecasts directly for the upper limit, while some, e.g., the Midcontinent Independent System Operator (MISO), allow VERs to provide their own forecasts (also referred to as self-forecasts). However, due to potential gaming concerns, there may be some limitations around obtaining a waiver from uninstructed dispatch deviation penalties if a VER were to use its own forecast. Since VERs typically offer at very low prices, at zero or negative offers to reflect production-based subsidies, they typically will be scheduled at their upper operating limit. If the actual output of the VER is different than the schedule, there often are no (or very relaxed) penalties, outside of a standard imbalance settlement from the DAM. However, during periods where the transmission system is congested and options to relieve that congestion lie primarily with the VERs, they will be sent a schedule less than their upper operating limit. In this case, VERs must curtail to ensure the transmission path is not overloaded, and they will be penalized if they do not do so within the allowed margins. This operation is mostly true for wind power across all ISOs, is the case for solar in those regions that have significant amounts and will likely be the case for solar in all regions given similarities.

In regions with capacity markets, VER also participate differently than conventional resources. Their contribution to reliability needs and contributing to peak conditions is based on their location and availability during those time periods where the peaks occur, rather than forced outages. ISOs typically use effective load carrying capability (ELCC) or approximations of ELCC for their capacity market contribution; for example, production during peak four to six hours of three summer months to develop its capacity contribution. VERs can then sell that percentage of their nameplate capacity into the capacity market. The value is typically about 10%–20% for wind and 40%–60% for solar. In regions with much higher solar penetration, the number can be much lower as the peak shifts to after sunset.

To this point, VERs have been limited in their participation in ancillary service markets. Fast response due to power electronics shows great performance with respect to capability. VERs also provide primary frequency response and voltage control, which is often not compensated through competitive ancillary service markets. However, several reasons limit their practical participation in ancillary service markets, including operator confidence in the availability of energy if the service were to be scheduled in advance (due to their uncertainty of output) and economics (i.e., if it costs nothing to provide energy, is there any value to hold back energy to provide ancillary service?) (Kahrl et al. 2021). However, VERs do participate in ancillary service markets in a few regions across the world. Forecasting VER production at different time horizons, and the data required to do so accurately, is a key factor that may also have an impact on hybrid resources. The philosophy of eliminating uninstructed deviation penalties or must-offer rules for VER due to the uncontrollable nature of their fuel source is also a key question that requires greater thought for hybrid resources. A generic mathematical depiction of VERs in market clearing software is detailed in equations 1 through 4.

$$R_{ver,t}^{r^+} \geq R_{ver}^{r\%^+} P_{ver}^{max} \qquad \forall\, R^+, VER, t \qquad (1)$$

$$R_{ver,t}^{r^-} \geq R_{ver}^{r\%^-} P_{ver}^{max} \qquad \forall\, R^-, VER, t \qquad (2)$$

$$P_{ver,t} + \sum_{R^+} R_{ver,t}^{r^+} \leq P_{ver}^{forecast} \qquad \forall\, VER, t \qquad (3)$$

$$P_{ver,t} - \sum_{R^-} R_{ver,t}^{r^-} \geq 0 \qquad \forall\, VER, t \qquad (4)$$

Assuming that VERs are eligible to provide ancillary services both in the upward and downward reserve categories, equations 1 and 2 specify the different reserve category requirements for each VER as a certain percentage of its maximum power output limit. VERs can satisfy the response requirements for existing upward reserve categories but would need to be curtailed beforehand, for example, prior to the significant event for contingency reserves (e.g., spinning reserve), and have enough forecasted available energy to meet the corresponding reserve duration requirement. Equation (3) restricts the sum of the real power generation and upward reserve types scheduled from VERs to be less than their forecasted power output. Some ISOs, such as Southwest Power Pool (SPP), allow dispatchable VERs that are curtailable to provide regulation down service, which may be depicted using equation (4).

2.2 Stand-alone Electric Storage Resource Electricity Market Participation

Limited energy storage resources (LESRs), such as flywheels and batteries, have primarily participated in ISO regulation markets for several years due to software limitations for provision of energy and other ancillary services, and since regulation service is typically the most lucrative for limited energy characteristics and only requires 15 minutes of sustained energy. However, more recently, batteries are increasingly providing energy time-shift and qualifying as resource adequacy capacity. Presently, four-hour duration batteries (compared with LESR) are the norm across the country, with longer duration energy storage in the early stages of procurement (Denholm et al. 2019).

FERC Order No. 841 was a primary catalyst for the RTOs/ISOs that are FERC jurisdictional to put in place changes to their market design and market clearing software to accommodate stand-alone ESRs. FERC issued Order No. 841 in February 2018 to enhance participation of stand-alone ESRs in RTO/ISO energy, ancillary services, and capacity markets by establishing a participation model that recognizes their physical and operational characteristics. Other RTOs/ISOs that are not under FERC jurisdiction have also continued their stakeholder initiatives and design proposals in very similar ways and with similar features to Order No. 841. With respect to market rules, all FERC-jurisdictional ISOs/RTOs have now complied with all or most requirements under Order No. 841, and the new ESR participation models have been implemented, although with future modifications planned in many cases. Most recently, in 2022, MISO's ESR model became operational. Both the PJM Interconnection (PJM) and ISO New England (ISO-NE) are currently scheduled to implement consideration of SoC in 2026. In 2022, modifications to the rules for stand-alone storage participation models continued in different ISOs/RTOs. For instance, the California Independent System Operator (CAISO) made improvements to SoC modeling to account for energy use when providing frequency regulation.

Although Order No. 841 required that ISOs must allow self-management of SoC, there was no definitive statement within the Order on what SoC management means, resulting in different interpretations and requests for clarifications (since the Order did not require ISO-SoC-Management but still required provision of SoC related bid parameters by ESRs and for ISOs to consider them). Consequently, different market regions offer different options for SoC management with a few that offer multiple options.

1. *Self-Schedule*: ESR self-dispatches its output and is insensitive to price. This option is allowed by all ISOs/RTOs.
2. *Self-SoC-Management*: ESR provides an offer curve analogous to traditional resources and can set offers to ensure desired and feasible SoC. ISO schedules the ESR without SoC consideration. This option is allowed by CAISO and the New York Independent System Operator (NYISO).
3. *SoC-Management-Lite*: ESR provides an offer curve. ISO does not schedule the ESR if it would lead to infeasible SoC, and the schedules are not optimized across time to optimize ESR schedules. Each hour is solved independently and sequentially in a sequential economic dispatch problem, only using the previous hour's data for initial conditions. SoC is used in each market interval to ensure the ESR's schedule is feasible. The previous hour's SoC is a parameter in economic dispatch/ locational marginal price (LMP) calculation. This option is allowed by ISO-NE, MISO, PJM, and SPP.
4. *ISO-SoC-Management*: This option does not require offers, but ESRs may still provide an offer curve, e.g., to account for degradation costs. The ISO ensures SoC feasibility and optimality by optimizing ESR schedules across time to minimize cost. All hours in the day-ahead operating horizon are solved simultaneously as one problem in a simultaneous multi-interval security-constrained economic dispatch (SCED) problem. SoC is managed across a known horizon to ensure feasibility and optimality, either by incorporating an end of horizon desired SoC constraint or a value in $/MWh provided by the ESR to demonstrate the value of keeping energy left over at the end of the day. The previous hour's SoC is a variable in the economic dispatch / LMP calculation. This option is allowed by CAISO and NYISO.

A simplistic and generic mathematical depiction of the physical and operating characteristics of ESRs in the market clearing software under the ISO-SoC-Management option is detailed in equations 5 through 11 below for illustration. It is crucial to note that the mathematical formulation in market clearing software is highly dependent on the SoC management and software options.

$$P^d_{esr,t} - P^c_{esr,t} + \sum_{R^+} R^{r^+}_{esr,t} \le MaxD_{esr} \qquad \forall\, ESR, t \qquad (5)$$

$$P^d_{esr,t} - P^c_{esr,t} - \sum_{R^-} R^{r^-}_{esr,t} \ge -MaxC_{esr} \qquad \forall\, ESR, t \qquad (6)$$

$$SOC_{esr,1} = SSOC_{esr} - \frac{1}{\eta^d_{esr}} P^d_{esr,1} \frac{\Delta T}{T} + \eta^c_{esr} P^c_{esr,1} \frac{\Delta T}{T} \qquad \forall\, ESR \qquad (7)$$

$$SOC_{esr,end} = TSOC_{esr} \qquad \forall\, ESR \qquad (8)$$

$$SOC_{esr,t} = SOC_{esr,t-1} - \frac{1}{\eta^d_{esr}} P^d_{esr,t} \frac{\Delta T}{T} + \eta^c_{esr} P^c_{esr,t} \frac{\Delta T}{T} \qquad \forall\, ESR, t \qquad (9)$$

$$SOC_{esr,t} \leq SOC_{esr}^{max} - \eta_{esr}^{c} \sum_{R^-} \left(R_{esr,t}^{r^-} \frac{\kappa^{r^-}}{T} \right) \qquad \forall\, ESR, t \qquad (10)$$

$$SOC_{esr,t} \geq SOC_{esr}^{min} + \frac{1}{\eta_{esr}^{d}} \sum_{R^+} \left(R_{esr,t}^{r^+} \frac{\kappa^{r^+}}{T} \right) \qquad \forall\, ESR, t \qquad (11)$$

$$P_{esr,t}^{d} \geq 0, P_{esr,t}^{c} \geq 0, R_{esr,t}^{r^+} \geq 0, R_{esr,t}^{r^-} \geq 0, SOC_{esr,t} \geq 0.$$

Equations 5 and 6 describe the maximum discharge and charge power limitations on the real power scheduled from an ESR, respectively. Equations 7 through 11 model the SoC constraints for an ESR. Equation 7 models the required stored energy level at the end of the first interval of the optimization horizon and considers the initial SoC parameter for an ESR. In most designs that have been proposed by ISOs/RTOs to date that use the ISO-SoC-Management option, the responsibility of determining the initial SoC as input to the optimization across multiple intervals has been delegated onto the ESR operator to provide this information as an input parameter for the day-ahead markets. Analogously, Equation 8 models the required stored energy level at the end of the last interval of the optimization horizon and helps to avoid myopic decisions that may empty out the ESR, depleting any stored energy for the future intervals. Without this restriction, the stored energy level would likely be zero at the end of the optimization horizon since the objective function would use all the available stored energy to reduce costs.

In the studies performed here, the desired SoC at the end of the last interval of the optimization horizon was modeled to return to the stored energy level at the beginning of the optimization horizon—that is, set to equal the initial SoC used in Equation 7, and used 50% SoC as an initial condition—under one of the hybrid storage participation options, i.e., the 2R ISO-Managed co-located participation model. This same modeling feature was also considered when developing the bids/offers under the 1R Self-Managed hybrid participation model. Equation 9 describes the stored energy throughput constraint and models the relationship between the ESR's stored energy level in two different time intervals, as well as the impact that scheduled discharge and charge has on its SoC or stored energy level. The SoC for each interval is determined by considering the stored energy level in the previous interval, as well as the amount of energy charged and discharged, while considering specific efficiencies associated with charging and discharging. Here, *T* denotes the time unit (i.e., fixed to 60 minutes) and *ΔT* denotes the duration of the time interval (e.g., 60 minutes in the DAM and 5–15 minutes in the RTM).

Equations 10 and 11 ensure SoC feasibility and bound the stored energy level of an ESR to be below its maximum SoC threshold and above its minimum SoC threshold, respectively. Moreover, an ESR is not allowed to provide upward (downward) reserve, such as regulation up (down) reserve, when operating at its minimum (maximum) SoC limit. It is crucial to include these constraints for LESRs such as batteries since the scheduled reserve may be limited by the current stored energy levels. Furthermore, the proposed formulation of ESR operation in equations 10 and 11 is one optional way for the optimization problem to ensure that the ESR has available storage to charge or available energy to discharge should downward or upward reserves be deployed in a particular interval, respectively, while also accounting for the corresponding reserve type's sustained duration requirement. It is extremely unlikely that all reserve types are deployed in all intervals in a specific direction, so Equation 9 is not extended to also consider the impact of reserve provision on SoC. In might still be beneficial to extend Equation 9 to also consider the impact on SoC from regulation reserve provision given the frequency of its deployment, but it is not worthwhile to extend Equation 9 to also consider the impact of other reserve types that are not deployed as often. That would then result in the solution being extremely conservative, where for instance the optimization will hold back 24 times the required reserve amount over the day in the DAM. The modeling approach for ancillary services may differ by region based on existing rules and operating procedures in place, so this topic has scope for further research.

2.3 Hybrid Resource Proposed Market Participation Models

Electricity market participation options vary regarding responsibility and complexity. The design and complexity of the participation model may depend upon the configuration of the hybrid resource and the existence of other features such as the investment tax credit (ITC) for that project. Although this study provides a few qualitative and quantitative advantages and disadvantages of the different participation modeling options for hybrids, no one option is recommended over another. As a matter of fact, if the participation modeling options are proven to be technically feasible, reliable, and cost-effective, and if prioritized appropriately, it may be beneficial for the ISOs/RTOs to allow all participation models. Note, however, that implementation of new participation models costs money and requires prioritization, and computational limits in some cases may prevent perceived value. Still, asset owners have the option to choose the model that best fits them based on their goals and offering strategies, subject to system reliability. Prior research has explored four different potential hybrid resource participation options, and these are described in Figure 1 (EPRI 2019; Gorman et al. 2020; EPRI 2021a).

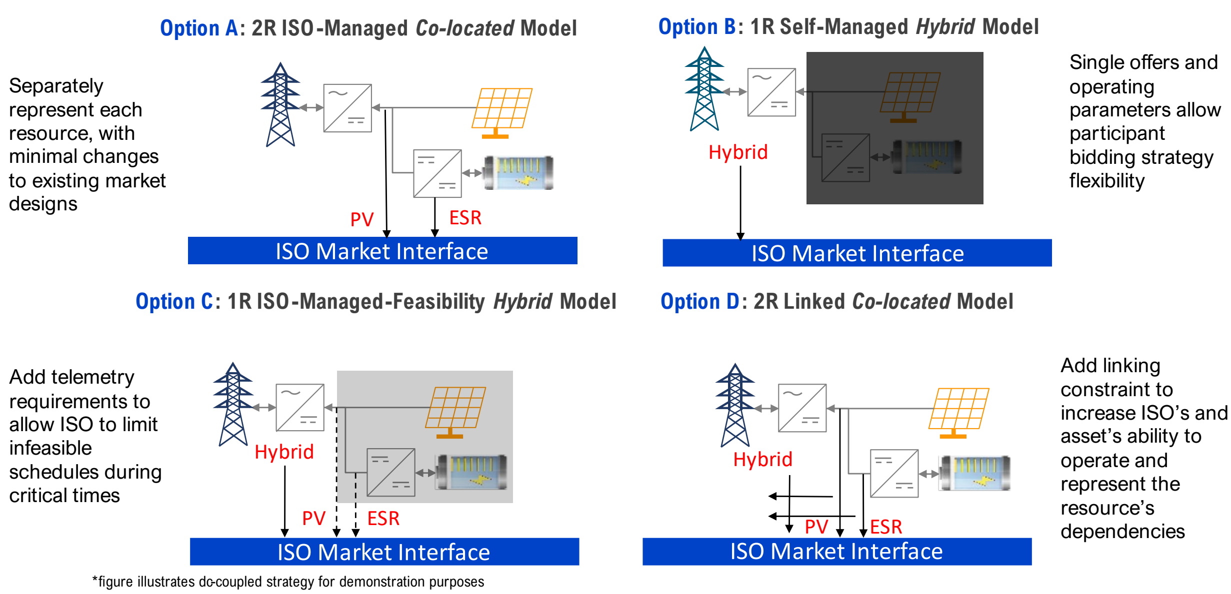


Figure 1. Different configurations of hybrid storage resource participation models.

2.3.1 2R ISO-Managed Co-located Participation Model

Each technology constituting the hybrid resource participates in the market independently using its existing participation model, including its scheduling constraints, and bidding (or offer) parameters. The unique characteristics of each constituent technology are represented explicitly and captured separately with minimal changes to existing market designs allowing for ease of integration. For instance, equations 1 through 4 may be used to represent the distinctive features of the VER component, and equations 5 through 11 for the ESR component, with the main hypothesis being that the SoC of the ESR component is managed by the system operator in this participation option. The combined hybrid resource output can be restricted by an interconnection constraint or the AC/DC inverter capacity limit. This restricts the power supply from the combined asset to less than the sum of the capacity limit of the individual components that make up the hybrid resource and in effect functions like a “radial” transmission line constraint. This restriction may be represented using Equation 12 below, where the rating (or the upper bound) of the radial transmission line is set to be equal to the aforesaid inverter limit (may require DC rating of the inverter for DC-coupled resources to ensure feasibility of the combined capability of the individual resources). This constraint is analogous to existing approaches to modeling the aggregate maximum capacity limit for a generating facility with multiple resources that is also limited by its interconnection limit. In that case, the injection capability of individual resources that constitute such a generating facility is limited by predefined participation factors. The use of predetermined participation factors may result in a solution that is less economically efficient when compared to the suggested constraint below, which results in a better (or if not, the same) solution owing to the potential expansion of the feasibility space.

$$P_{ver,t} + \sum_{R^+} R^{r^+}_{ver,t} + P^{d}_{esr,t} - P^{c}_{esr,t} + \sum_{R^+} R^{r^+}_{esr,t} \leq \overline{F}_{line,t} \quad \forall\, VER, ESR, LINE, t \quad (12)$$

This suggested approach helps mitigate reliability concerns related to over-paneling but is likely to impact the computational complexity of existing scheduling problems due to the subsequent increase in the number of constraints (radial transmission line constraints) and variables (hybrid resources) with increasing penetration levels of hybrid resources. Moreover, the suggested approach also allows for modeling flexibility, since it may be extended to model multiple hybrid resources that are behind the same point of interconnection (POI), under an interconnection agreement, i.e., by using multiple secondary radial transmission constraints for each hybrid and a primary radial transmission constraint that ties all the secondary radial transmission constraints together to the grid. This option is currently implemented and available in CAISO, where the aforesaid constraint is referred to as the *aggregate capability constraint* (ACC). In this option, the ISO/RTO has complete information on anticipated production and any limitations, allowing for optimal use and reliability. It is straightforward since offer, settlement, and mitigation rules require little modification. However, this option may not fully reflect certain characteristics, including the ability for the ESR to charge from the VER component and the limits on charging the ESR from the grid that are applied from the ITC. Additionally, this option may provide less flexibility on offering strategies from the asset owner, who might have limited ability to use internal advanced offer tools.

2.3.2 1R Self-Managed Hybrid Participation Model

The hybrid resource participates in the market as a single integrated resource using a set of single resource bid/offer strategies and operating parameters analogous to conventional generators and flexible loads. In other words, the treatment in market clearing software is like traditional thermal resources, with the exception that the resource can now also charge (typically modeled as negative injection or negative production) from the grid (akin to stand-alone ESRs). The hybrid resource asset owner uses (dynamic) bidding strategies to self-manage the resource's unique characteristics such as the SoC of the ESR component, and will be held responsible to ensure the safe, reliable, and economic operation of the facility. A simplistic representation of this participation option is detailed in equations 13 through 15 below.

$$P_{hyb,t}^{d} - P_{hyb,t}^{c} + \sum_{R^+} R_{hyb,t}^{r^+} \leq MaxD_{hyb,t} \qquad \forall\, HYB, t \qquad (13)$$

$$P_{hyb,t}^{d} - P_{hyb,t}^{c} - \sum_{R^-} R_{hyb,t}^{r^-} \geq -MaxC_{hyb,t} \qquad \forall\, HYB, t \qquad (14)$$

$$P_{hyb,t}^{d} - P_{hyb,t}^{c} + \sum_{R^+} R_{hyb,t}^{r^+} \leq F_{line,t}^{Rate} \qquad \forall\, HYB, LINE, t \qquad (15)$$

Equations 13 and 15 may also be combined into a single constraint with the maximum discharging limit of the hybrid storage resource being equal to the lesser of the sum of the maximum discharge limit of ESR and maximum capacity of VER or the hybrid facility's interconnection/inverter limit. Alternately, the ISOs may elect to use only one scheduling decision variable to represent both charging and discharging decisions simultaneously, given that this modeling option does not explicitly include time coupled SoC constraints, making the problem simple, straightforward, and computationally tractable.

This option can allow the hybrid facility owner to utilize their internal capabilities that fully reflect its knowledge of resource capabilities. It allows for participant bidding strategy flexibility. It is fairly simple to implement and may avoid computational issues with ESR SoC management and VER forecast management. Additionally, the asset owner will also have full capability to ensure meeting requirements of U.S. ITC. However, the ISO/RTO does not explicitly incorporate constraints related to individual technologies that constitute the hybrid, i.e., the ISO does not manage the SoC of the ESR component nor the VER component's forecasts. Hence, the scheduling software may result in infeasible schedules without such knowledge. Moreover, the ISO has limited to no visibility into the feasibility of energy or ancillary services that can be provided by the hybrid storage facility, especially during critical periods. This option may require further market design and stakeholder discussion, with particular emphasis on settlements and mitigation rules (e.g., verifiable costs and withholding rules).

2.3.3 1R ISO-Managed-Feasibility Hybrid Participation Model

This participation option is similar to the 1R self-managed hybrid participation option, where the hybrid facility owner still self-manages its characteristics as a single integrated resource with single offers. However, in this option, the ISO also evaluates forecasts of the VER component and SoC levels of the ESR component to ensure the hybrid resource schedule is feasible. Therefore, in this option, the ISO would still need the same data and telemetry as the 2R ISO-managed co-located participation option to ensure feasible schedules and for situational awareness.

2.3.4 2R ISO-Managed Linked Co-Located Participation Model

This option allows for incorporation of an additional "linking" constraint between the constituent technologies that otherwise participate in the market independently. The linking constraint represents the dependent condition that makes the hybrid resource operate differently than if it were two independent resources; for example, by limiting grid charging or charging otherwise clipped energy from the co-located VER. A simplistic representation of the linking constraint is shown in Equation 16. A hybrid asset owner may opt to change the lower bound of Equation 16 on a dynamic basis to accommodate different ITC considerations. For instance, if the lower bound of this equation is set to zero, then the hybrid resource cannot charge from the grid and can only charge from its on-site renewable resource, making it eligible for full ITC benefits (or otherwise partial/pro-rated ITC benefits as long as it charges greater that 75%) under incentives that were in place in the United States prior to the 2022 Inflation Reduction Act (IRA).

$$P_{ver,t} - \sum_{R^-} R^{r^-}_{ver,t} + P^{d}_{esr,t} - P^{c}_{esr,t} - \sum_{R^-} R^{r^-}_{esr,t} \geq -\underline{F}_{line,t} \quad \forall\, VER, ESR, LINE, t \quad (16)$$

The remainder of the equations under this option are the same as the 2R ISO-Managed Co-located Participation Model that was presented above. This option may allow for more flexibility on considering dependent operating conditions across the technologies that make up the hybrid resource; e.g., the ability to satisfy U.S. ITC requirements. Generally, combined-cycle resources use an analogous advanced modeling approach in many ISO/RTO regions, where each constituent component (i.e., steam or combustion turbine) is modeled individually, but the transition constraints and transition costs are based on the configuration of the entire plant. This can allow for improved capture of characteristics and efficiency, but also has the potential to increase complexity and concerns with market manipulation and physical withholding. Moreover, under this option, the asset owners will need to manage the interconnection rights and ensure that there are no conflicting offers or must offers. For hybrid resources, this additional linking constraint assists with conforming eligibility for the ITC. However, this option may become dated in the future, since the storage component now qualifies for a stand-alone ITC benefit regardless of whether it charges from the grid or from the VER as per the provisions of the IRA, and the PV solar component may increasingly elect a production tax credit (PTC) over the ITC benefit as PV costs fall. This constraint is currently implemented and available in NYISO, referred to as the scheduling limits for a co-located storage resource. It also includes an option to apply a threshold to the asset's upper scheduling limit similar to equation 12 by curtailing solar/wind using its output limit flag to ensure deliverability of services by the ESR component. This constraint is also being considered for implementation in CAISO as part of the suggested improvements for its co-located model to "avoid grid charging."

Other alternatives of participation options are also being discussed in the industry. In addition, hybrid resource developers, similar to traditional resources, have the choice to select the self-scheduled participation option. With the self-scheduled participation option, the owner of the hybrid resource asset determines a fixed dispatch schedule and acts as a price-taker based on that schedule. Consequently, self-scheduled hybrid resources can establish their own schedule and receive the prevailing wholesale market clearing price for the power they provide. This option is applicable to both 1R and 2R options. Furthermore, it is possible that additional participation options, more intricate and not yet considered, may emerge in the future.

2.4 Outlook for Electric Storage and Hybrid Storage Resource Participation in Wholesale Electricity Markets, and Electricity Market Participation Design Status of Hybrid Storage Plus Renewable Resources

Due to policy drivers, higher market prices, and improvements in participation rules, wholesale electricity markets are an attractive opportunity for some emerging technologies, including stand-alone battery energy storage and hybrid storage resources. Several wholesale electricity market regions have seen tremendous growth in stand-alone storage and hybrid or co-located storage resources in recent years. With about 7 gigawatts (GW) in operation in the US markets by end of 2022, stand-alone battery energy storage was a major entrant in some regions, and hybrids are also starting to participate at a higher scale. By end of 2022, about 60% of the new batteries in the US markets are in the CAISO footprint, including just over 3 GW of new stand-alone lithium-ion battery storage and just under 2 GW of batteries in hybrid projects (almost all solar), with 137 projects of both types connected to the grid. The Electric Reliability Council of Texas (ERCOT) has the next highest battery capacity, with about 2.7 GW. Other ISO/RTOs have less new battery capacity, although ISO-NE has 104 projects, most of smaller size, tallying to about 316 MW.

Based on planning and commercial forecasts, by 2030, it would not be surprising for energy storage to comprise 5%–20% of peak load, based on the region, with California having by far the largest forecast storage resource portfolio (about 12–14 GW). The quantity of battery storage in interconnection queues—in both stand-alone and hybrid projects—continued to increase into 2022, although also with significant withdrawals since 2021. At end of 2022, there were about 3,000 projects accounting for over 450 GW of battery capacity in ISO queues, with the heaviest concentrations in PJM, CAISO, and ERCOT. Duration is typically not specified in the queue data, but longer-duration batteries (6–8 hours) are now being procured in the western US. The federal tax incentives approved under the IRA of 2022, along with other federal and state incentives and grants, are expected to increase the rate of storage and hybrid project development significantly over the remainder of the decade. In addition, some storage projects at risk of termination due to economic pressures over 2021–2022 have been allowed to renegotiate contract pricing by some state regulators.

These regions have had to modify their electricity market designs to enable these emerging technologies to provide the wholesale market products and services they are capable of providing, either because they are required through regulatory directives or because they have prioritized the design enhancements in their stakeholder processes. Hybrid resource design initiatives have been a high priority at all the ISOs/RTOs over the past few years, building on the earlier storage initiatives.

CAISO is the leader in current capacity and operations of hybrids; an informational report (CAISO 2022) in late 2022 found almost perfect performance of about 425 MW of hybrids registered as capacity resources during summer of 2022. While there are fewer hybrids already in operation elsewhere, there are over 1,000 hybrid projects in ISO/RTO queues, with almost all being PV-battery hybrids. This subsection provides the latest information (as of end of 2022) on where designs are as it relates to market participation of hybrid resources across the different market regions (EPRI 2021b). Table 1 summarizes the design characteristics that are common across all the FERC jurisdictional ISOs/RTOs first in the gray box, followed by some unique features in the design features for each individual ISOs/RTOs.

Table 1. Summary of ISO/RTO hybrid storage resource market design proposals for participation modeling option

Market Design Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
Participation Model	❖ Most entities are proposing two separate participation modeling options: Co-located (2R; two separate resources model) and hybrid (1R, single integrated resource model)					
	2R: CSR (IPR, ESR) CSR scheduling constraints; Wind or Solar Output Limit flag allocated to co-located IPR (if CSR schedules ~90% of CSR Injection Scheduling Limit). Currently being expanded to include ESRs with CTs, landfill gas, and limited control run-of-river hydro. **1R**: HSR model under development to support storage integrated with different generator types.	**2R**: VER, ESR (SoCM-Lite) **1R**: Adopt larger parent fuel-type model in the interim *Future*: ESR (fully applicable to open-loop hybrids; partially applicable to closed-loop hybrids) ✓ Solar-Battery Hybrids: ESR (except add solar-only mode, delete non-energy regulation & reserves modes, closed-loop model lacks negative MW functions)	**2R**: owner to ensure Order 845 appropriately accounted for; DVER, MSR (SoCM-Lite) **1R** (HSMR): currently (Generating Unit, Plant), considering MSR, but 2R EMS (reliability) Model. If HSMR not registered as MSR and its ESR component is capable of charging from the grid, then provision to include withdrawn energy in a load settlement location.	• **2R**: ✓ VER: SOR, non-dispatchable generator, DNE dispatchable generator ✓ Battery: SOR, CSF • **1R**: SOR, CSF (preferred by ISONE), Intermittent Generator	• **2R**: DIR, ESR (SoCM-Lite) • **1R**: Generation Resource, DIR, or SER Type II/ESR • **ECC** (in the 5y horizon)	**2R** (co-located resource): ACC (master, subordinate); ESR allowed to deviate from dispatch instruction & reduce output under certain conditions; ISO may curtail EIR based on its bid curves or operating needs **1R** (hybrid resource): NGR

ACC: Aggregate Capability Constraint; **AS**: Ancillary Service; **ATRR**: Alternative Technology Regulation Resource; **BSF**: Binary Storage Facility; **CSF**: Continuous Storage Facility; **CSR**: Co-located Storage Resources; **CT**: Combustion Turbine; **DAM**: Day-ahead Market; **DARD**: Dispatchable Asset Related Demand; **DIR**: Dispatchable Intermittent Resource; **DNE**: Do-Not-Exceed; **DVER:** Dispatchable VER**; ECC**: Enhanced Combined Cycle; **EIR**: Eligible Intermittent Resource; **ELR**: Energy Limited Resource; **EMS**: Energy Management System; **ESF**: Energy Storage Facility; **ESR**: Electric Storage Resource; **HSL**: High Sustained Limit; **HSMR**: Hybrid Storage Market Resource; **HSR**: Hybrid Storage Resource; **IPR**: Intermittent Power Resource; **MSR**: Market Storage Resource; **NGR**: Non-Generator Resource; **POI**: Point of Interconnection; **PSH**: Pumped Storage Hydro; **RA**: Resource Adequacy; **RTM**: Real-time Market; **SER**: Storage Energy Resource; **SoC**: State of Charge; **SoCM**: SoC Management; **SOR**: Settlement Only Resource; **VER**: Variable Energy Resource

Most ISOs are proposing two separate participation modeling options for hybrid storage facilities: (1) the co-located or two separate resources model (also referred to as *2R*), and (2) the hybrid or single integrated resource model (also referred to as *1R*). Some ISOs have made explicit co-located (separate) participation models with injection limits and withdrawal limits modeled. Hybrid (integrated) resources are sometimes allowed, but ISOs are evaluating additional design features for this model. Foundational hybrid market design initiatives were conducted in the Alberta Electric System Operator (AESO) and Independent Electricity System Operator (IESO) in 2022, while CAISO, ISO-NE, and NYISO conducted more targeted revisions. In addition to solar and wind, several ISOs put an emphasis on developing rules for other hybrid designs, e.g., with combustion turbines, landfill gas, and hydropower.

ERCOT does not utilize the terminology of hybrid or co-located resources; instead, ERCOT observes AC-coupled and DC-coupled resources. ERCOT defines a DC-couple resource as “A type of Energy Storage Resource in which an Energy Storage System is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection, and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current inverter(s).” During the “combo model” DC-coupled resources will be treated separately as a controllable load resource and a generation resource at the same node. The generation resource includes both the wind/solar generator and the discharging portion of the battery. Offers and schedules will be provided and received separately. During the “single model” DC-coupled resources will be treated as a single resource to the grid with a high limit set to the minimum of the injection limit and the sum of each technology’s capacity ratings. Qualified scheduling entities representing this resource will provide a single bid-to-buy and offer-to-sell that can include its negative (battery charging) to positive (battery discharging or wind/solar producing) range. The timeline for updating bids will be the same as for ESRs, just prior to the operating hour. ERCOT and its stakeholders have determined that no rule changes were required for AC-coupled resources that can participate as a separate resource (generator and storage).

IESO has proposed two “foundational” participation models:

1. Co-located Hybrid Facility Model: This model features three separate resources registered at a single point of interconnection, including a separate dispatchable load and dispatchable generator as the separate storage model and the third dispatchable generator. It includes three offer curves per hybrid, with separate scheduling and settlement.
2. Integrated Hybrid Facility Model: This model features two separate resources registered at a single point of interconnection, including a large dispatchable generator (to denote injection from energy storage and on-site generator) and a separate dispatchable load (to denote charging from energy storage). It includes two offer curves per hybrid, with separate scheduling and settlement.

AESO supports hybrid asset configurations for co-located storage and variable energy resources, which can elect whether to be represented as integrated or separate assets in its long-term energy storage market participation draft recommendation. A regulatory filing of its final energy storage rule amendments, including those for hybrids, is expected to be filed with the Alberta Commission in 2023.

3. Case Study

3.1 Introduction

This study aimed to evaluate the overall production cost impacts, steady-state reliability impacts, and potential revenue impacts from significant hybrid resources participating in energy markets using the different proposed participation modeling options. Its main goal was to evaluate the key differences that alternative market designs for hybrid resources have on key metrics through modeling, simulation, and analysis, while focusing impacts on day-ahead (DA) and real-time (RT) energy markets.

3.2 Process: Tools and Data

This subsection describes the study approach to develop a realistic simulation of the operations of a wholesale electricity market using a state-of-the-art commercial market modeling software tool, i.e., Power System Optimizer (PSO), to evaluate the specific impacts of hybrid resource participation models from both the system operator and market participant perspectives. A comprehensive representation of existing market operational procedures was established within the tool and then applied to a dataset that represents a realistic wholesale electricity market, i.e., the New York Independent System Operator (NYISO) system. The system was first set up for a base case without hybrid storage resources and then hybrid storage resources were included in the system to analyze different case simulations.

3.2.1 Description of the Market Simulation Software Tool

Power System Optimizer is a commercial-grade production cost model (PCM) simulation tool developed and licensed by Polaris. PSO is built on the AIMMS platform and connects to commercial solvers, such as GUROBI and CPLEX, and is used by several leading industry organizations. PSO realistically represents available information over different market timelines through an advanced unit-commitment (UC) and economic dispatch (ED) model. It is a multi-cycle, multi-timescale, steady-state power system operations simulation tool that aims at replicating the full-time spectrum of scheduling resources to meet energy and reliability needs of the bulk power system (BPS). The PCM attempts to replicate actual system operations at a high time resolution and allows for flexibility to accommodate the many different market and operational structures that are in existence throughout the world. Each of the sub-models can consider varying levels of detail of variability and uncertainty impacts and how to accommodate it, with different binding decisions that are used as inputs in later sub-models as the model moves forward in time.

This is the only way to measure detailed reliability and economic efficiency impacts from variability and uncertainty and how new operational strategies and market designs (for example, in this study, enhanced participation design options for hybrid resources) may mitigate these, and other impacts. Simulation tools that model multiple cycles can more realistically represent the impacts of variability and uncertainty and the mitigation strategies for those impacts.

Previously available simulation tools did not capture the multi-cycle, multi-decision, and multi-timescale approach of realistic steady-state electricity operations. However, as the horizon approaches real time, the uncertainty is increasingly resolved, and as the timescale becomes closer to instantaneous, the variability impact decreases. Additionally, fewer options are available to the system operator as the horizon approaches real time. These previous simulation tools were therefore more suited to simulating environments with low uncertainty and variability. PSO can solve large-scale systems and can be used to demonstrate applications on realistic systems and better understand practical impacts. PSO also includes advanced participation models for several specific technologies, such as combined cycle and pumped storage hydropower. PSO is used for a variety of applications due to its flexible engine that can mimic electricity markets and vertically integrated systems, e.g., asset valuation under different technology and resource mixes, operational and fuel price sensitivities, renewable integration studies, profitability, ancillary services, regional market design, and policy analysis.

3.2.2 Description of the Realistic Dataset

In this subsection, the focus is on the PCM development approach for the zonal New York BPS test case. To ensure that the regional model aligns with NYISO's operations and scheduling processes while remaining computationally tractable, a range of enhanced modeling features were integrated. Although NYISO's interconnection queue presently indicates a lower deployment of hybrid storage resources relative to other ISOs, it is preparing for future hybrid resource development.

The zonal NYISO test case was based on the NYISO *2020 Load and Capacity Data* report (Gold Book), and includes about 5,433 MW of nuclear resources, 12,654 MW of combined cycle (CC) resources, 11,945 MW of steam turbine (ST) resources, 5,702 MW of combustion turbine (CT) and internal combustion (IC) resources, 1,409 MW of pumped storage hydropower (PSH) resources, 4,343 MW of conventional hydro resources, 1,985 MW of wind resources, 57 MW of utility-scale solar resources, 315 MW of distributed photovoltaic, and 41 MW of storage resources. Traditional resources' operating characteristics are determined by technology and fuel type, including heat rate curve shape, non-fuel operation and maintenance costs, startup/shutdown costs, startup/shutdown times, minimum up/down times, and capabilities for quick-start, regulation, and spinning reserve. Data on thermal generator operating characteristics were gathered from similar unit types in the North American Electric Reliability Corporation (NERC) *Generating Availability* report and industry data from S&P Global. Nuclear units are treated as must-run and operate continuously except during refueling, maintenance, and forced outages, with historical outage information incorporated into the model. Conventional hydroelectric resources are modeled as energy-constrained generators, with their generating capabilities based on monthly water flow patterns. Hourly energy output is optimized for minimum systemwide production costs. Wind and solar generation are represented with hourly generation profiles. Fuel prices, including natural gas, are derived from historical data, and assigned based on proximity to gas trading hubs. Ancillary services are co-optimized with energy, including regulation, 10-minute spinning reserves, 10-minute non-spinning reserves, and 30-minute reserves. However, *hybrid storage resources are excluded from reserve provision* for the purpose of this study. The reserve modeling approach considers nested reserve requirements. Analysis of historical ancillary service bids informs the determination of resource bid offers and associated costs.

The PCM for the NYISO region incorporates the following time-series data: The load data for NYISO utilizes 2012 historical load shapes and is adjusted using publicly available data to align with the 2019 historical peak and annual energy demand for each zone in NYISO. Accordingly, for the chosen simulation months of April and July, the observed peak load in the NYISO region reaches about 18,438 MW and 30,953 MW, respectively. The wind shapes for the NYISO region are derived from NREL's Wind Toolkit Dataset and calibrated to match annual production based on NYISO's *2020 Load and Capacity Data* report. These shapes correspond to the 2012 weather year. Distributed PV resources in each zone of NYISO are associated with a weather station located in the largest metropolitan area of that region, and NREL's PVWatts Calculator is utilized to generate a standardized hourly PV generation profile. These profiles are then adjusted according to NYISO's annual installed capacity forecast. The BTMPV nameplate capacity data for each NYISO zone is sourced from NYISO, which includes energy reduction from behind-the-meter PV (BMPV) installations as reported in the Gold Book load forecast report. The NYISO model reflects plant-level conventional hydropower data from 2019 obtained through ABB's Velocity Suite. The modeled interchanges (i.e., imports and exports) with neighboring areas account for actual flows in 2019, obtained from historical data provided by NYISO.

For this study, the imports and exports were modeled as fixed schedules based on historical observed levels. To account for economic impacts, the cost of imports and revenue from exports were assumed to align with the nodal prices at their respective nodes. While there may be limitations to this approach in future scenarios with a greater reliance on VER, nuclear, and other clean energy sources, for this study, it was considered adequately accurate to model the neighboring regions as described given the net zero emission goals in neighboring regions and uncertainty around the direction of exchanges.

The NYISO PCM incorporates enhanced features to ensure accurate modeling aligned with current operations and scheduling processes. Transmission modeling considers network limitations from key interfaces between zones. Incorporating hybrid resources into a nodal model without network upgrades can lead to unintended intra-zonal congestion or infeasibilities. To address this, the NYISO system was modeled at a zonal level instead of a nodal level for this study, relaxing intra-zonal network constraints except for non-contingency interface constraints. Emission allowance prices were included in the model to account for greenhouse gas policy. Daily natural gas price forecasts were incorporated to capture the value of energy arbitrage provided by storage-based resources, mitigating energy price spikes resulting from gas price volatility. The use of daily gas price forecasts improves the modeling of peak energy prices and enables better representation of energy arbitrage between days with low and high gas prices.

3.3 Bid Strategy Development for the 1R Self-Managed Participation Model

Incorporating hybrids in a self-managed participation model into a PCM requires emulating the bids each hybrid owner would submit to the market. Different from fuel-based generators, where marginal cost bids are tied to commodity prices, and from VERs, where they are near zero, ESRs have an effective marginal cost based on expectations of future prices. This key challenge in modeling hybrid bids is exacerbated by a lack of historical data on the bidding decisions of hybrid and ESR agents, due to the recency of their presence in wholesale electricity markets. This subsection describes this study's approach to creating bids consistent with those a hybrid participant would submit, without the knowledge of historical market outcomes. The approach, depicted in Figure 2, includes an optimization model representing hybrid decision-making and a process for executing it in a PCM simulation.

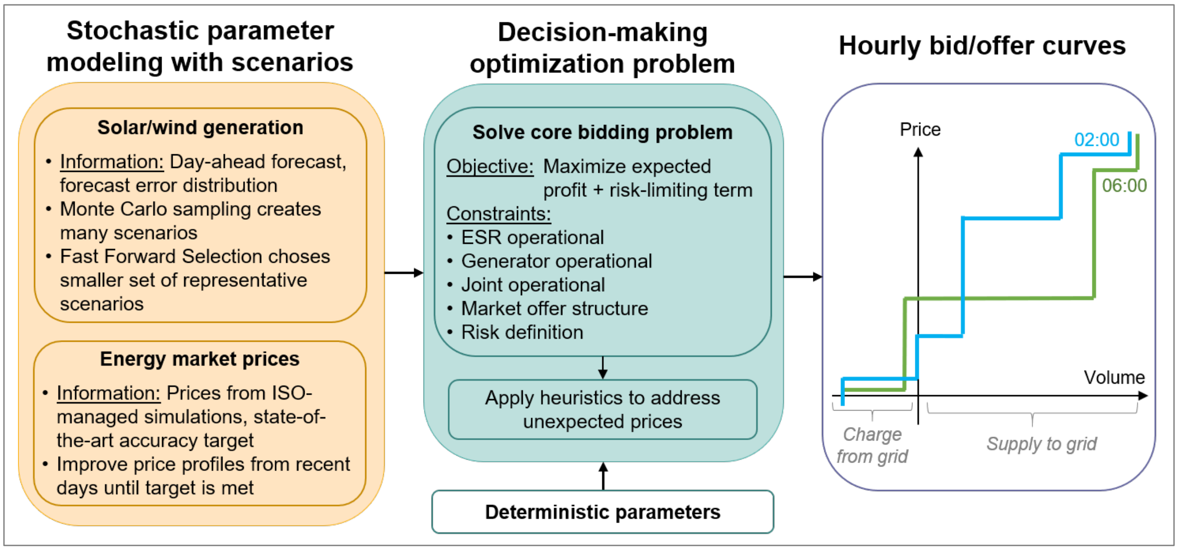


Figure 2. Bid strategy methodology overview

First, we developed a stochastic optimization model to support hybrid participant decision-making in day-ahead markets under uncertainty in VER production and market prices. The model outputs include hourly price-quantity bid curves with a limited number of non-decreasing marginal price steps. These bid curves were then input to the PCM. This model was informed by literature on market participation strategies for hybrids and hydro-electric plants, in particular Lohndorf et al. (2013); Ghavidel (2020); Rahimiyan and Baringo (2016); Liu, Xu, and Tomsovic (2016); and Jamali et al. (2016), yet it is differentiated by its approach to guaranteeing valid market bids and requiring only the information available in these types of forward-looking applications. At a high level, the model reflects a price-taker hybrid operator seeking to maximize their expected operating profits while managing risk due to uncertainty. Uncertainty is represented in the model by scenarios expressing possible realizations of renewable generation potential and market prices in the future. Our approach to developing these scenarios is discussed next. The model considers a 48-hour time horizon, even though the simulated market only takes bids for the first 24 hours, to produce bids based on a more complete view of the opportunity costs of ESR actions, particularly for hours late in the day. Details of the model formulation are available in (Mulvaney Kemp 2022).

Obtaining bids from the stochastic optimization model described above requires the development of scenarios and choice of model hyperparameters. Our approach to this task was designed to reflect the accuracy of information typically available to a market participant at the time they make day-ahead bidding decisions. Further, the approach aimed to consistently produce bids that perform well and are not overly sensitive to small changes in the model inputs. Key time-series scenarios were developed as follows:

- Renewable generation: First, a large number of scenarios were constructed sequentially around a day-ahead forecast by uniformly sampling from the empirical distribution of errors in periods with similar forecast values and similar error values in the preceding period. Then, the Fast Forward Selection algorithm picked 20 representative scenarios from this set. The set of sampled scenarios and the day-ahead forecast were assigned probabilities of 0.2 and 0.8, respectively, based on experiments testing the relative accuracy of each.
- Day-ahead prices: A set of plausible price profiles were built around the prices obtained from simulations of the system with hybrids in the 2R ISO-managed co-located participation model. Current state-of-the-art electricity price forecasting produced weekly weighted mean absolute errors (WMAE) of ~5% on average (Weron 2014; Yang, Ce, and Lian 2017). Based on this, we began with scenarios set as the "2R" price profiles of recent days, distinguishing between weekdays and weekends. Then, these scenarios were incrementally improved until they met the 5% WMAE target, i.e., until they were representative of state-of-the-art forecasts.

A symmetric scenario tree was created to pair each generation scenario with each day-ahead price scenario. Day-ahead price scenarios are deemed equally likely, so the combined scenario probabilities were proportional to the generation scenario probabilities.

In practice, the ESR's SoC at the beginning of the day is known or can be accurately estimated, making it a deterministic parameter. Commercially available PCMs do not allow for the co-simulation of battery SoC and hybrid participant decision-making. A result of this software limitation for multiday studies is that bids for the entire study horizon (e.g., weeks' worth of bids) must be submitted to the "market" in advance. In this case, what initial SoC should be used when making decisions for day 7, for example, given the uncertainty in generation and dispatch for days 1–6? Instead of selecting a single value, bidding curves were developed that correspond to each of a set of initial SoC values. Then, for each simulated DAM, the PCM utilized only the single set of bidding curves corresponding to the observed state of charge. For the example in Figure 3, the bidding decision-making problem is solved five times: once using an initial SoC of s_1, once using an initial SoC of s_2, etc. Then, if the SoC at the end of the previous day's simulation falls within band 2, the PCM will use the set of bids based on s_2. A larger number of narrow bands will improve the bids but increase computation and memory requirements. This study used the values listed in Table 2; narrower bands near the extreme values were used to guard against infeasible schedules early in the day.

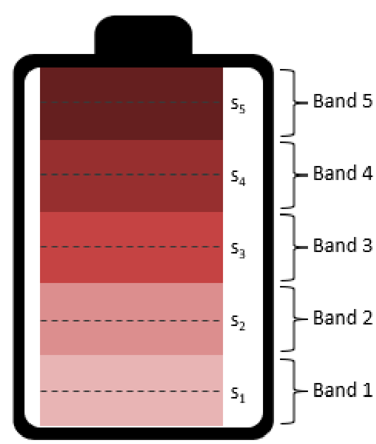


Figure 3. Illustration of solution to initial SoC

Table 2. Values used to define and select state-of-charge dependent bidding curve sets

Initial SoC (%)	2.5	12.5	30	50	70	87.5	97.5
Band	[0, 5]	(5, 20]	(20, 40]	(40, 60]	(60, 80]	(80, 95]	(95, 100]

Lastly, we implemented a heuristic to reflect the hybrid operator's interest in capitalizing on unexpectedly high and low prices—a key advantage of bidding curves over self-scheduled bids. The day-ahead price scenarios developed above allow for elasticity over a range of probable prices, as determined by the prices observed in recent weeks and state-of-the-art forecasting. However, it is feasible that prices may spike outside of this scenario range, for example if there is a line fault or unplanned generator outage. With these low-probability events in mind, we designed a heuristic which extends the bids determined by the optimization model to offer more power when prices are exceptionally high and offer to charge the ESR when prices are exceptionally low, while reflecting the generator's cost of operation. Details are available in Mulvaney Kemp (2022).

3.4 Market Simulations Setup

This subsection includes a detailed description of the established baseline market operational procedures to enable the market simulations. The market operations simulations reflect state-of-the-art operations in RTO/ISO regions and include two specific market timelines. In this case, the planned multi-cycle simulation approach includes a day-ahead market (DAM) and a real-time market (RTM), with forecast errors occurring between the two markets.

Day-ahead Market Structure. The DAM structure includes a day-ahead unit commitment and economic dispatch model, which commits the long-lead resources, schedules the hybrids based on the submitted offer strategies, and uses day-ahead forecasts. The day-ahead scheduling cycle has a three-day optimization horizon, which includes a 24-hour binding window and a 48-hour look-ahead or advisory window at a 1-hour time-resolution.

Real-time Market Structure. NYISO's real-time scheduling process includes both a longer-term real-time unit commitment (RTUC) model and a shorter-term real-time economic dispatch (RTED) model. However, for the purpose of this study, the RTM structure included a single real-time unit commitment and economic dispatch model with a one-hour optimization horizon at a one-hour time resolution for simplicity and ease of implementation and interpretation. It allowed for the commitment of quick-start resources and the re-dispatch of committed resources to address real-time imbalances. Furthermore, in the context of hybrid resources, the real-time scheduling cycle was structured to demonstrate the effectiveness of the participation models based on physical capabilities and limitations, such as:

1. VER forecast errors
2. ESR minimum and maximum SoC limitations, and
3. Hybrid resource interconnection limitations (e.g., restricted grid charging and point of interconnection [POI] capacity constraints).

Real time was represented as real-time operation (and not as a separate RTM with updated hybrid resource bids), which allowed for a better understanding of the isolated impacts from hybrid participation in the DAM. In this phase of the study, the focus was on the impact of hybrid resource participation models in the day-ahead time frame. This assisted in separating out the impacts from real-time re-optimization that could be evaluated in a future phase of the study, as well as potentially separating out the challenges associated with ancillary services impacts on participation models. Thus, the different suggested participation options were applied to the DAM only. Moreover, in this study, real-time operation of hybrid resources was represented by two different operational plans of the hybrid resource's day-ahead schedule as detailed below. In this context, the real-time operational plans were essentially used to mimic possible behavior when forecasted conditions change from day-ahead conditions.

1. **Storage Follow (SF):** Schedules for the storage component of the hybrid resource will be interpolated from its day-ahead market schedules as long as the SoC of the storage component is at a level that it can do so.
2. **Hybrid Balance (HB):** Allow for the storage component of the hybrid resource to do whatever it needs to do to meet the day-ahead hybrid resource schedule when there are VER forecast errors.

There will still be load and VER forecast error (including VER from the hybrid facility) between the day-ahead and real-time scheduling cycles in both real-time operational plans. Each option is an approximated RTM strategy that allows for the team to have more confidence in the study on day-ahead participation. Updating hybrid storage resource bids in real time or utilizing real-time re-optimized SoC management are both complex and out of scope for this study, which focuses on day-ahead participation. In reality, forecast deviations may not necessarily be an issue as such, depending on the resource mix. Other system resources might be able to manage the imbalances across the system (e.g., if wind were reduced in real time but load was also reduced simultaneously it may not be necessary for the storage component to make up for the lost wind to meet the hybrid day-ahead schedule as indicated by the HB real-time operational plan). However, this gives a directional assessment on the future cases where we look at real time. The next phase of the study will potentially allow for updates to hybrid resource day-ahead offers to allow for re-optimization of hybrids in real time and better accommodate the impacts from forecast deviations, for instance.

3.4.1 Software Adaptations to Facilitate Market Simulations

One of the key contributions of this study is to develop the capability in state-of-the-art software to simulate different hybrid participation models within wholesale electricity markets. To enable running the planned market operations simulations effectively, the study team made several software adaptations to state-of-the-art production cost modeling software, as detailed below.

1. Incorporated a modeling feature to allow for a SoC-dependent offer curve set (i.e., set of offers/bids for each hour of the next day) for the hybrid plant in the day-ahead time frame under the 1R self-managed hybrid participation modeling option.
2. Developed the capability within the software to select the appropriate offer curve set for the

parent hybrid plant[1] based on the observed SoC of the child storage resource under the 1R self-managed hybrid participation modeling option. The implementation of the 1R self-managed hybrid participation modeling option requires the incorporation of pseudo-2R modeling in the DAM and the RTM, which includes representation of both the child injectors to allow for monitoring of the SoC of the child storage resource. The end goal of this software modification is to mimic contemporary DAM structures that allow for offer/bid updates each day, whereas in typical PCM simulations such bids/offers will need to be submitted all at once for a longer study time frame.

3. Developed the ability to utilize the observed SoC of the child storage resource from the end of the previous binding horizon of the day-ahead optimization run to update the bid/offers for the parent hybrid plant for the upcoming optimization horizon of the day-ahead optimization run under the 1R self-managed hybrid participation modeling option.
4. Implemented logic to accommodate dummy child storage injectors, which are not directly linked to the grid but instead connected indirectly through a nomogram constraint that associates them with their parent hybrid plant. These child storage injectors were modeled with distinct physical and operational characteristics, such as varying SoC limits, across different timeframes, including day-ahead and real-time. Additionally, the minimum SoC constraint was relaxed to permit negative SoC values, enabling the evaluation of schedule feasibility under the 1R self-managed hybrid participation model and within different real-time operational plans.
5. Established a consistent preferred violation sequence in the market clearing software. The implemented simulation approach in the PSO software tool incorporates a logic to support a specific preferred violation sequence, i.e., based on the physical capabilities and limitations of a hybrid resource. This is accomplished by adjusting the penalties for violation variables in real time with the priority sequence as follows: (i) to violate the storage real-time operational plan, i.e., SF & HB, constraints; (ii) to curtail the VER component in real time; (iii) to violate power balance constraints; (iv) to violate hybrid interconnection (or inverter) constraints; and (v) to violate SoC feasibility restrictions for the ESR component. Penalty prices are set to guide the optimization model to follow this preferred sequence (but are not factored into pricing/costs).
6. Incorporated modeling aspects to avoid simultaneous storage charge and discharge schedules.
7. Incorporated logic to ensure appropriate resetting of storage SoC through different market simulation days.

[1] In the context of this study, the hybrid facility is commonly referred to as the parent, while the storage and renewable components are often referred to as its offspring or children.

4. Analysis and Simulation Results

4.1 Case Study Scenario Matrix

To enable a comprehensive understanding of the several issues of interest in the study, a case study matrix (Table 3) was developed in consultation with technical advisors and industry experts. Different cases were prioritized based on the sensitivities that had the most interest and relevance to the impact of participation options for hybrid storage resources, ways to model the different participation options and real-time operations, and ways to provide for insights of how the system and asset owner implications compare under different operating conditions. To provide insight into the future implications of different participation options, the case scenarios consider levels of hybrid resource deployment that go beyond the level expected in the near term and levels of VER that consider existing regional goals for future resource mixes.

Table 3. Case study matrix

	NYISO	
Sensitivity Type	**Current VER Resource Mix**	**High VER Resource Mix: 70% VER with 9 GW offshore wind, 6 GW DPV, and the rest land-based wind and utility-scale PV**
Operational Sensitivities		
Unrestricted Grid Charging	X	X
No Grid Charging	X	
Real-time Operation: Storage Follow (SF)	X	X
Real-time Operation: Hybrid Balance (HB)	X	X
Hybrid Resource Penetration Sensitivities		
Low Hybrid Penetration	X	
High Hybrid Penetration		X
Hybrid Resource Participation Option Sensitivities		
2R ISO-Managed Co-located Participation Model	X	X
1R Self-Managed Hybrid Participation Model	X	X
2R ISO-Managed Linked Co-Located Participation Model	X	

As detailed in Table 3, the planned study scenarios include diverse combinations of:

- two different VER penetration levels (current and high),
- two different hybrid resource penetration levels (low and high),
- two different hybrid operational grid charging sensitivities (no restrictions on grid charging, and storage resource to charge from co-located VER exclusively and avoid grid charging),

- two different hybrid real-time operational strategies (SF and HB), and
- three different hybrid resource participation option sensitivities (2R ISO-Managed, 1R Self-Managed, and 2R ISO-Managed Linked).

As described earlier, the composition of the resource mix for the low renewable penetration sensitivity is based upon a historical NYISO base case that was benchmarked for 2019. Furthermore, the low hybrid resource penetration scenario incorporates about 473 MW of new battery storage additions to hybridize about 973 MW of existing VER facilities, i.e., 57 MW utility-scale PV and 916 MW of wind. The composition of the resource mix for the high renewable penetration sensitivity includes about 70% VER penetration based upon near-term VER targets in the NY Region. This includes about 9 GW of offshore wind generation and 6 GW of distributed photovoltaic (DPV) solar generation, with the remainder from land-based wind generation and utility-scale photovoltaic (UPV) solar generation. The high VER mix also includes about 3,000 MW of storage, of which about 1,500 MW of storage is hybridized with co-located VER, i.e., about 2,084 MW of utility-scale PV and 916 MW of wind, for the high hybrid penetration scenario. Note that the duration of energy storage is not specified in NYISO planning documents, but this study assumes four-hour duration and 85% roundtrip efficiency for all storage.

It is important to note that this is *not* a NYISO study, and that the objective is *not* to design the future system scenario specific to NYISO future plans. The choice of a New York system was based on availability of a realistic dataset, state goals that aligned with the study's needs, and existing hybrid interest. The high VER mix was designed using the New York Climate Leadership and Community Protection Act (CLCPA) near-term VER mandates as a starting point to plausible goals in the New York region. These sensitivity inputs included capacity informed by CLCPA's target of 70% of New York's power generation from renewable energy by 2030. Specific near-term targets for resource technologies were used to make informed decisions while changing the resource mix, within reason (e.g., retirement of some nuclear, CT, IC, and ST resources). Additionally, long-term forecasts for coal, fuel oil, and natural gas fuel prices were obtained from the EIA annual energy outlook for the year 2030.

The proposed renewable buildout and location to fulfil the high VER target mandated by the NY CLCPA is outlined in Table 4. All resource additions are allocated among the different NYISO zones based on the NYISO Congestion Assessment and Resource Integration Study (CARIS) 70 x 30 scenario assumptions. Furthermore, additional onshore (or land-based) wind and utility-scale solar capacity was added in a 1:1 ratio until the 70% renewable energy goal was reached. Table 4 shows the capacity additions by zone and by resource type. The proposed allocation of VER and storage resources, as identified in the NYISO CARIS 70x30 scenario, was further modified in this study to enable suitable placement of hybrid storage resources (particularly solar hybrid storage in lieu of their significant penetration in ISO/RTO interconnection queues when compared to wind hybrid storage) in zones with potentially greater energy arbitrage opportunities (for the assumed system conditions) and larger regional loads, and to enable an enhanced understanding of the study's various issues of interest. This study's proposed modified high VER sensitivity capacity buildouts by resource type and zone is detailed in Table 5.

Table 4. High VER sensitivity capacity buildouts by resource type and zone

Zone	Offshore Wind Additions (MW)	Land-Based Wind Additions (MW)	Distributed PV Additions (MW)	Utility PV Additions (MW)	4-Hour Storage Additions (MW)
A	0	1,470	558	2,249	150
B	0	1,282	391	251	90
C	0	1,568	825	1,675	120
D	0	821	137	0	180
E	0	985	774	858	120
F	0	0	932	2,067	240
G	0	0	685	1,227	90
H	0	0	71	0	90
I	0	0	88	0	90
J	6,300	0	518	0	1,350
K	2,700	0	904	0	480
Total	**9,000**	**6,126**	**5,883**	**8,327**	**3,000**

Table 5. Modified high VER sensitivity capacity buildouts by resource type and zone

Zone	Offshore Wind Additions (MW)	Land-Based Wind Additions (MW)	Distributed PV Additions (MW)	Utility PV Additions (MW)	4-Hour Storage Additions (MW)
A	460	1,470	558	1,609	200
B	0	1,282	391	251	90
C	450	1,568	825	1,225	300
D	0	821	137	0	280
E	0	985	774	858	235
F	0	0	932	2,067	240
G	460	0	685	767	190
H	0	0	71	0	190
I	0	0	88	180	90
J	5,390	0	518	910	725
K	2,240	0	904	460	508
Total	**9,000**	**6,126**	**5,883**	**8,327**	**3,048**

The last subsection provides detailed results for each case and then draws conclusions based on a comparison of the results across the different cases with differing participation options, real-time operational strategies for hybrid storage resources, grid charging restrictions, and resource mixes.

4.2 Hybrid Technical Configurations

The technical configurations of the hybrid resources, i.e., generator and battery sizing, were based on insights from other studies, commercial activity, and alignment with other ongoing projects. Specific parameters were chosen for each participation option to be comparably represented in the tool for analysis in simulations.

All hybrids were AC-coupled with a battery that has a power capacity equal to *half* of the paired generation capacity, a duration of four hours, and a round-trip efficiency of 85%. AC-coupled configurations are most common today, including those among greenfield plants (Bolinger et al. 2022), and they allow for the same model used for wind hybrids, which are always AC-coupled, to also be used for solar hybrids. The 0.5 storage-to-generation capacity ratio is consistent with a survey of developers and utilities in MISO, which reported an expected ratio of 0.25–0.75 for 67% of planned hybrids (Kristian and Prorok 2021), and the ratio of ~0.65 based on all proposed hybrid storage, solar, and wind capacity in interconnection queues (Joseph et al. 2022). The survey results in Kristian and Prorok (2021) also support a choice of four-hour duration, with 86% of respondents planning 2–4 hours of storage. At the end of 2021, operational solar hybrids had a weighted average duration of 3.2 hours, while wind hybrids averaged just 0.6 hours (Bolinger et al. 2022). However, wind-plus-storage hybrids are still nascent, therefore we did not rely on this value in our forward-looking model. Each point of interconnection has the same power capacity as the wind or solar generation behind it, consistent with the finding in Bolinger et al. (2022) that proposed hybrid plants "expect to dispatch the battery only when the generator is operating at less than full output." Battery cycle limits and degradation costs were not imposed within the scope of this study. Finally, all hybrid batteries were assumed to begin the time horizon with a 50% SoC.

The scenarios used in the simulations to analyze the impacts of the participation models are described below. To provide into the future implications of different participation models, the scenarios should consider levels of hybrid resource deployment that go beyond the level expected in the near term.

4.3 Case Study Scenario Definitions

The main goal of this study was to implement and analyze the impacts of different market participation options for hybrid storage resources on key metrics including, but not restricted to, economic efficiency, reliability, and asset profitability through modeling, simulation, and analysis. In this study, simulations across different timescales, dispatch strategies, and hybrid configurations, and under different potential resource mix scenarios, were conducted and analyzed to better understand the impact of hybrid resource participation options on operations, particularly with an increased penetration of VER and hybrid resources.

Table 6 provides an exhaustive summary of the study case scenarios, including combinations of:

- two VER penetration levels (current and high),
- two hybrid resource penetration levels (low and high),

- two hybrid resource grid charging sensitivities (that is, *unrestricted grid charging* [no restrictions on grid charging], and *no grid charging* [storage resource to charge from co-located VER exclusively and avoid charging from the grid]),
- two hybrid resource real-time operational strategies (SF and HB), and
- three hybrid resource participation option sensitivities.

Each case scenario was simulated for two separate one-month simulation periods characterizing two different representative NYISO system operating conditions in a year: April (which typically experiences minimum instantaneous demand) and July (which often represents its maximum instantaneous demand). Market performance was simulated with a realistic NYISO dataset and its existing operational procedures for the cases described below, both in the absence and in the presence of hybrid storage resources with the suggested participation options. The central goal was to compare and contrast all sensitivities for the differing participation models, system scenarios, and real-time options.

The high VER penetration cases were run to assess whether changes in resource mix would impact results and to also understand the different impacts that VERs can have on the impacts of hybrid resources and hybrid resource participation options. The low VER penetration cases may be closer to existing conditions, but the high VER penetration cases may result in greater energy arbitrage opportunities due to potentially higher price volatility and an increased reliance on emerging technologies such as storage and hybrid storage.

Analogously, the high hybrid penetration cases were run to evaluate the expected differences in comparisons when increasingly a greater number of hybrid resources are built and participating in wholesale electricity markets, as well as to analyze whether the number of hybrids will impact results. Higher hybrid penetration levels may show different impacts, as there is potential for greater imbalances and increased occurrences of infeasible dispatch schedules when more hybrids are self-managed simultaneously. The low hybrid penetration levels, while still high compared to existing systems in many cases, may show closer conditions to what may be expected on the existing system or in the near future.

The different participation option cases were run to explore and compare the anticipated benefits and impacts of moving towards more advanced participation models for hybrid resources in market clearing software. The “no hybrid” cases were simulated for validation and benchmarking purposes and to design a base case to be used for assessing the impact of participation options.

The “no grid charging” (denoted as NoGC) cases were run for the low VER sensitivity to compare the results against the corresponding “unconstrained grid charging” (denoted as UnGC) cases. When avoiding grid charging, the hybrid resources may run into SoC limitations less often since it is expected that they may only charge otherwise clipped energy from the on-site VER. Furthermore, the “no grid charging” sensitivity was not conducted for the high VER penetration cases since it is anticipated that the commercial stand-alone storage ITC provision under the IRA might make the linking constraint (that restricts grid charging) irrelevant and dated for a future resource mix. The different UnGC cases were run to explore and compare the anticipated benefits and impacts of the chosen advanced participation models for hybrid resources.

The different real-time operational strategies of the hybrid resource's day-ahead schedule were run to understand how variations in realistic operating principles that still respect physical limitations in real time may influence results. Considering these strategies allowed the team to have more confidence in the study on day-ahead participation, and to obtain a directional assessment on the future research focused on real time participation. Additionally, the HB real-time operational strategy was run to better understand and clarify whether and how hybrid resources could be potentially beneficial by behaving analogously to base-load resources, i.e., by firming up its on-site renewable resource's day-ahead schedule. In other words, the HB option allowed for the hybrid resource output to be more consistent and predictable, despite renewable forecast errors. Lastly, as mentioned earlier, in this phase of the study, real time was represented as real-time operation (and not as a separate RTM with updated bids from the hybrid resources), which enabled the team to understand the isolated impacts from hybrid participation in the DAM.

Table 6. Simulation case scenarios

Simulation Case/ Period	VER Penetration	Hybrid Resource Penetration	Participation Option	Grid Charging Option	RTM Operation Strategy
1: April, July	Low VER	No Hybrid	n/a	n/a	n/a
2: April, July	Low VER	Low Hybrid	2R ISO-Managed, Linked	No Grid Charging	Storage Follow
3: April, July	Low VER	Low Hybrid	1R Self-Managed	No Grid Charging	Storage Follow
4: April, July	Low VER	Low Hybrid	2R ISO-Managed	Unconstrained Grid Charging	Storage Follow
5: April, July	Low VER	Low Hybrid	1R Self-Managed	Unconstrained Grid Charging	Storage Follow
6: April, July	Low VER	Low Hybrid	2R ISO-Managed, Linked	No Grid Charging	Hybrid Balance
7: April, July	Low VER	Low Hybrid	1R Self-Managed	No Grid Charging	Hybrid Balance
8: April, July	Low VER	Low Hybrid	2R ISO-Managed	Unconstrained Grid Charging	Hybrid Balance
9: April, July	Low VER	Low Hybrid	1R Self-Managed	Unconstrained Grid Charging	Hybrid Balance
10: April, July	High VER	No Hybrid	n/a	n/a	n/a
11: April, July	High VER	High Hybrid	2R ISO-Managed	Unconstrained Grid Charging	Storage Follow
12: April, July	High VER	High Hybrid	1R Self-Managed	Unconstrained Grid Charging	Storage Follow
13: April, July	High VER	High Hybrid	2R ISO-Managed	Unconstrained Grid Charging	Hybrid Balance
14: April, July	High VER	High Hybrid	1R Self-Managed	Unconstrained Grid Charging	Hybrid Balance

4.4 Key Metrics and Results

This subsection first provides a detailed description of the study's established key metrics that were used to evaluate the different participation options, and then summarizes the simulation results for the different case study scenarios defined above for each of the established metrics. Consideration of metrics that examine impacts from both system operator and asset owner perspectives for a large suite of scenarios is important to improve understanding of the implications on different power systems with different resource mixes. The main goal was to understand how the established metrics differ based on participation model, real-time operation, and hybrid resource sizing, and at different hybrid penetration levels, VER penetration levels, resource mixes, and ITC charging strategies.

Economic efficiency. Economic efficiency implications are explained through social welfare or operating costs (for a cost minimization problem). It is useful to evaluate the economics from a societal benefit perspective, e.g., which participation modeling option leads to the least production costs and why? Operating costs can be summarized as production costs only (i.e., the sum of fuel costs, no-load costs, and startup/shutdown costs) or also can include the costs of balancing violations. The latter are also referred to as "penalty costs" that are included in an optimization problem's objective function to ensure solution feasibility. They are typically reported as part of the total costs. In all the simulation case results that follow, the reported results for production costs, violations (if any), and the ability of hybrid resources to follow a real-time operational strategy are all based on the real-time scheduling cycle unless explicitly mentioned to be otherwise. The day-ahead costs are usually not as significant for conducting comparisons since the day-ahead costs are not necessarily realized. Additionally, the real-time production cost metric that is of focus here to better understand the economic efficiency implications of hybrid resource participation options does not include the costs of violations, since such violation costs are subjective to the choice of penalty factors ($/MWh) for the different violations.

Table 7 summarizes the production costs and production cost differences across the different case scenarios from the real-time scheduling cycle as described above. For the low VER penetration cases, delta operating cost demonstrates the percentage difference in real-time system operating costs when comparing a specific low VER, low hybrid case scenario against a base-case low VER, no hybrid case scenario (case 1) without hybrid resources. Analogously, for the high VER penetration cases, delta operating cost demonstrates the percentage difference in real-time system operating costs when comparing a specific high VER, high hybrid case scenario against the base-case high VER, no hybrid case scenario (case 10) that does not have any hybrid resources. Additionally, for all the case scenarios, each day-ahead security-constrained unit commitment (DASCUC) and real-time security-constrained unit commitment (RTSCUC) solution used a MIP Gap of 0.01%.

Table 7. Production cost results

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Operating Cost ($M)	Delta Operating Cost (%)
Low VER, April	No Hybrid	n/a	n/a	Case 1: Base	131.37	n/a
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	131.30	-0.05
				Case 3: 1R, NoGC	131.45	0.06
			Unconstrained Grid Charging	Case 4: 2R, UnGC	131.25	-0.10
				Case 5: 1R, UnGC	131.52	0.11
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	131.40	0.02
				Case 7: 1R, NoGC	131.41	0.03
			Unconstrained Grid Charging	Case 8: 2R, UnGC	131.47	0.07
				Case 9: 1R, UnGC	131.58	0.15
Low VER, July	No Hybrid	n/a	n/a	Case 1: Base	271.66	n/a
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	271.49	-0.06
				Case 3: 1R, NoGC	271.63	-0.01
			Unconstrained Grid Charging	Case 4: 2R, UnGC	271.38	-0.11
				Case 5: 1R, UnGC	271.67	0.00
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	271.60	-0.02
				Case 7: 1R, NoGC	271.69	0.01
			Unconstrained Grid Charging	Case 8: 2R, UnGC	271.52	-0.05
				Case 9: 1R, UnGC	271.72	0.02
High VER, April	No Hybrid	n/a	n/a	Case 10: Base	90.41	n/a
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	90.32	-0.10
				Case 12: 1R, UnGC	90.34	-0.08
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	90.30	-0.13
				Case 14: 1R, UnGC	90.28	-0.14
High VER, July	No Hybrid	n/a	n/a	Case 10: Base	242.67	n/a
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	242.33	-0.14
				Case 12: 1R, UnGC	242.73	0.02
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	242.45	-0.09
				Case 14: 1R, UnGC	242.45	-0.09

A few interpretations can be gained from the production cost results. First, the *2R ISO-Managed Co-located Participation* option seemed to perform better than the *1R Self-Managed Hybrid Participation* option by bringing about greater reductions in operating costs when compared to the base case scenario without any hybrids for the UnGC, SF cases in both April and July. This was observed to be true for both the low VER and high VER penetration cases. In fact, the *1R Self-Managed Hybrid Participation* option seems to have had a negative impact by increasing the operating costs when compared to the base case scenario for the UnGC, SF case in April for the low VER penetration case, and the July high VER penetration case. In these case scenarios, it was observed in the 1R option that the dependence of the hybrid facilities on the developed bidding strategies in the DAM resulted in infeasible day-ahead hybrid resource schedules in real time. That leads to increased reliance on more expensive quick-start generation resources (such as gas turbines [GTs] and internal combustion engines [ICs]) that must be used to replace the generation that is not available from the hybrid facilities in the RTM to ensure power balance. Moreover, the 2R option was better at scheduling the cheaper traditional thermal resources (such as combined cycle plants) that require day-ahead start-up notification while considering SoC feasibility of the storage component of the hybrid facilities; consequently, leading to lesser reliance on the more expensive resources (such as GTs and ICs) in real time. Given that the 2R option explicitly considered SoC, it also resulted in better utilization of the hybrid facilities in real time.

Analogously, for the low VER penetration scenario, the *2R ISO-Managed Linked Co-Located Participation* option (also referred to as 2R, NoGC) resulted in greater production cost savings when compared to the associated *1R Self-Managed Hybrid Participation* option (also referred to as 1R, NoGC) for the NoGC, SF cases. Similar to the UnGC, SF case, the *1R Self-Managed Hybrid Participation* option increased the operating costs when compared to the base case scenario for the NoGC, SF case in April due to an increase in reliance on the more expensive quick-start generation (such as GTs and ICs) that must be used to replace the generation that is not available from the hybrid facilities in the RTM in order to ensure power balance. However, the increase in operating costs when compared to the base case scenario for the 1R, UnGC, SF case in April was greater when compared to the 1R, NoGC, SF case in April. The capability to charge from the grid in the UnGC option resulted in the hybrid facilities being cleared to dispatch at their maximum charge and maximum discharge capacities more frequently in the DAM (due to the developed bidding strategies that eventually resulted in infeasible day-ahead schedules in real time) than the NoGC option (with less aggressive offers due to the dependence on the co-located VER component for charging). This resulted in an increased need to rely on more expensive quick-start generation to replace the infeasible generation from the hybrid facilities in real time for the 1R, UnGC option when compared to the 1R, NoGC option under SF.

Alternatively, the *2R ISO-Managed Co-located Participation* option seemed to perform better than the *2R ISO-Managed Linked Co-Located Participation* option. The ability of the hybrid facility to draw power (or charge) from the grid enabled more efficient resource scheduling within the system. For example, for the 2R case with UnGC, the hybrid facility could charge during periods of low-cost electricity, allowing for the provision of additional stored energy during peak hours when compared to the 2R case with NoGC. As a result, this approach yielded greater cost savings for the UnGC option when compared to the NoGC option in the 2R model, where grid charging was not available.

For the low VER penetration case scenario, the UnGC, HB real-time operational strategy cases also seemed to exhibit a similar trend to the UnGC, SF real-time operational strategy cases, wherein the *2R ISO-Managed Co-located Participation* option seemed to generally perform better than the *1R Self-Managed Hybrid Participation* option. For the month of April, although the *2R ISO-Managed Co-located Participation* option still seemed to perform better than the *1R Self-Managed Hybrid Participation* option for the UnGC, HB real-time operational strategy, both options increased operating costs when compared to the base case scenario without any hybrids. However, the increase in operating costs with the *2R ISO-Managed Co-located Participation* option (i.e., 0.07%) was lower than the *1R Self-Managed Hybrid Participation* option (i.e., 0.15%). In the low VER penetration scenario for April, for the UnGC, HB real-time operational strategy, in general for both 2R and 1R participation options, the simulations indicated that it might not always be advantageous for hybrid storage facilities to align their entire day-ahead schedule for every hour, particularly when there is a possibility of imbalance arising from errors in VER forecasts, since balancing the hybrid schedule for the present time period could hinder its ability to fulfill its day-ahead schedule later in the day, which could prove to be more advantageous for the system. This results in greater production costs when compared to the base-case scenario for both options. However, even in this case, the greater increases in real-time production costs under the 1R option are attributed to increased reliance on more expensive quick-start generation resources (such as GTs and ICs) that must be used to replace the generation that is not available from the hybrid facilities in the RTM to ensure power balance.

Moreover, in the low VER penetration scenario during the peak load month of July, it is important to acknowledge that the reduction in operating costs for the HB real-time operational strategy with 2R and UnGC was not as significant as the reduction observed in the SF case. Specifically, the operating cost reduction was lower for the former, with a difference of -0.05% compared to -0.11% in the latter. This disparity can be attributed to the nature of the HB real-time operational strategy, as previously mentioned. Furthermore, even in this case, the *2R ISO-Managed Co-located Participation* option still outperformed the *1R Self-Managed Hybrid Participation* option in terms of operating cost reduction. The latter option, in fact, increased the operating costs by 0.02% compared to the base case scenario, specifically for the HB case with UnGC in July. Given the peak load conditions in July and the nature of the HB real-time operational strategy, there is a need to either commit and dispatch additional capacity from combined cycle resources (CCs) or steam turbines (STs) for the two alternate participation options to satisfy the increase in demand—and replace the generation that is not available from the hybrid facilities due to violations of the HB real-time operational strategy when compared to April. For the low VER, July simulation period, under the HB real-time operational strategy, for both unconstrained and no grid charging cases, the 2R option generally performed better than the 1R option and resulted in greater cost savings due to the more efficient scheduling of CCs and lesser generation from the more expensive STs in 2R when compared to 1R. In general, CCs tend to be more efficient when operating at higher generation levels and do not need to decrease generation to provide flexibility.

Finally, for the high VER penetration case scenario, for the UnGC, HB real-time operational strategy cases, both the participation options had similar impacts on the real-time production costs when compared to the base case scenario without any hybrids, with differences, if any, either being within or at the MIP gap of 0.01%.

Reliability. When introducing changes to the market clearing software, it is prudent to assess their reliability implications under differing resource mixes. For instance, is it possible for certain scenarios, particularly with elevated levels of hybrid resource penetrations, to lead to infeasible hybrid resource schedules awarded that can have reliability implications owing to the changes that were introduced? How often may this happen and what is the reasoning for its occurrence? Are there any immediate enhancements to consider, including those to prevent it from happening?

For the most part, economic implications are the key results, but other results such as reliability challenges were also examined in this study, since system operators and balancing authorities are primarily concerned with maintaining system reliability while doing so at the lowest cost possible. Steady-state reliability metrics such as power imbalances and reserve shortages that may be observed in real-time operations are used to understand the reliability implications of the suggested hybrid resource participation options. The comprehensive PCM used in this study included the simulation of both DA and RT scheduling cycles. This allowed for the identification and reporting of scenarios in which there is an imbalance between supply and demand in the RT cycle, which is expected to occur infrequently but may become more common in future systems due to greater uncertainty between DA and RT. Additionally, this modeling approach enables the detection of situations in which the reserve capacity is inadequate to meet existing regulation or contingency reserve requirements in the RT cycle.

For the test system under consideration, no reliability concerns were observed for the simulated case scenarios. For example, no instances of violations of the storage SoC constraints, or hybrid resource inverter/ interconnection constraints, or power imbalances (such as load-shedding or over-generation) and reserve shortages were observed in the real-time scheduling cycle across all the simulated case scenarios. However, it is important to note that this outcome may not be applicable to alternative test systems featuring dissimilar resource mixes, such as a scenario characterized by restricted quick-start or ramping capabilities, limited transmission capacity, or more significant integration of hybrid and renewable energy resources that may yield different reliability conclusions.

Profits and incentives. Evaluating the profitability and incentives is crucial when determining the most advantageous participation option for a hybrid resource asset owner, assuming truthful cost-based offer strategies. This assessment helps to identify which option provides the highest benefits and why. Typically, in wholesale electricity markets, short-run profits are calculated using a two-settlement system considering the two sequences of periods (day-ahead and real time) for financial settlements. In this context, the *day-ahead revenue* takes the sum of the product of the day-ahead schedules and the day-ahead LMPs for each hour of the simulation. The *real-time revenue* only takes the sum of the product of the deviation of real-time schedules from the day-ahead schedules and the real-time LMPs for each one-hour real-time period of the simulation. It essentially ignores the day-ahead schedules. The “two-settlement profit” is the closest to a realistic profit that may be gained by a hybrid storage resource, given existing market designs. It takes the day-ahead revenue and then adds (subtracts) the product of positive (negative) deviation from the day-ahead schedules based on real-time schedule and the real-time LMP. While the two-settlement profit result gives a good indication of actual profits received, the day-ahead and real-time revenues provide insights on what may be occurring in all the simulation cases.

Table 8 shows the total short-run profits (also referred to as the *two-settlement profit*) for all the hybrid storage resources within each simulation. It also includes the delta profit for each of the case scenarios, which denotes the percentage difference in two-settlement profits when comparing the 2R participation option against the corresponding 1R participation option. These results do not include any make-whole payment settlements and are purely based on schedules and LMPs. They also do not reflect any ITC benefits and do not factor in any additional costs of the storage component of the hybrid resource beyond the costs to charge energy (e.g., cycling/ degradation, and operation and maintenance costs are ignored and would essentially lower any profits further). A few interpretations can be obtained from the aggregate hybrid resource revenue and short-run profit results, as detailed below.

First, during the April simulation period, it is observed in both the low VER and high VER penetration scenarios that the *1R Self-Managed Hybrid Participation* option generally resulted in higher revenues from the DAM compared to the *2R ISO-Managed Co-located Participation* option (2R, UnGC) and the *2R ISO-Managed Linked Co-Located Participation* option (2R, NoGC) in both SF and HB real-time operational strategies. This is mainly because the developed bidding strategies for the 1R option generally result in higher cleared day-ahead hybrid resource schedules compared to the 2R cases that explicitly consider SoC. However, due to physical and operational limitations, such as SoC restrictions, the hybrid storage resources often need to buy back or repurchase a significant portion of the energy that they cannot provide in real time, typically at real-time LMPs that are higher than the LMPs paid in the DAM. This can be observed from the larger amounts of energy buybacks in real time for the 1R option when compared to the 2R options. In general, the *1R Self-Managed Hybrid Participation* option has an increased likelihood for not being able to provide what was cleared in the DAM in real time, due to the aggressive hybrid resource bidding strategies and the absence of explicit SoC consideration in the market clearing software when determining the cleared day-ahead hybrid resource schedules to begin with. This results in discrepancies and SoC infeasibilities that are further aggravated by hybrid resource forecast errors and cannot be used as-is in real time, hence the energy buybacks in real time to respect physical limitations. Consequently, the two-settlement short-run profits are consistently greater for the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option under both SF and HB real-time operational strategies, despite the day-ahead revenues being greater for the *1R Self-Managed Hybrid Participation* option.

One exception for the month of April is the high VER penetration, UnGC case scenario under the HB real-time operational strategy, where the two-settlement profit for the *2R ISO-Managed Co-located Participation* option was lower than the *1R Self-Managed Hybrid Participation* option by a mere 0.77%. As mentioned earlier, for this specific case, the results for the real-time production cost impacts for the two alternate participation options were comparable, with differences being within the optimality gap of 0.01%, so the slight differences in the profit results may also be attributed to effectively obtaining different optimal solutions with the established MIP gap. In other words, the differences in the real-time revenues for the two alternate participation options for this specific case might be further impacted if a different solution were to be obtained for either of the participation options that is within the duality gap. This then impacts the two-settlement profit as well.

Second, for the July simulation period, for both the low VER and the high VER penetration case scenarios, the *1R Self-Managed Hybrid Participation* option typically resulted in lower revenues from the DAM when compared to the *2R ISO-Managed Co-located Participation* option (2R, UnGC) and the *2R ISO-Managed Linked Co-Located Participation* option (2R, NoGC) under both SF and HB real-time operational strategies, since the cleared day-ahead hybrid resource schedules were generally lower with the developed bidding strategies when compared to the 2R cases that explicitly considered SoC. Furthermore, the hybrid storage resources were then also required to buy back much of the energy that they could not provide in real time due to SoC restrictions or otherwise, typically at real-time LMPs that were greater than the LMP that was paid in the DAM.

In general, the *1R Self-Managed Hybrid Participation* option has an increased likelihood of not being able to provide what was cleared in the DAM in real time due to the absence of explicit SoC consideration in the market clearing software when determining the cleared day-ahead hybrid resource schedules to begin with. This results in discrepancies and SoC infeasibilities that are further aggravated by hybrid resource forecast errors and cannot be used as-is in real time; hence the energy buy-backs in real time to respect physical limitations. For July, the energy buybacks in real time were generally greater for the 1R participation option when compared to the 2R participation options, apart from the UnGC case under the HB real-time operational strategy for both the low and high VER penetration scenarios. It is projected that *the HB real-time operational strategy can potentially result in comparable or greater real-time buybacks for the 2R participation option in some cases. This is because it is entirely possible for the storage component's SoC to unpredictably run low or high from trying to balance out forecast errors from the renewable component in a previous interval under the HB operational strategy*. This trend was observed in the UnGC case under the HB real-time operational strategy for both the low and high VER penetration scenarios for the July simulation period. Nevertheless, overall, for the July simulation period, the two-settlement short-run profits were consistently greater for the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option under both SF and HB real-time operational strategies when compared to the *1R Self-Managed Hybrid Participation* option.

Table 8. Aggregate hybrid resource revenue and short-run profit results

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Day-ahead Revenue ($k)	Real-time Revenue Only ($k)	Two-settlement Profit ($k)	Delta Profit (%)
Low VER, April	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	2,932.58	(113.59)	2,818.99	5.64
				Case 3: 1R, NoGC	3,228.42	(559.88)	2,668.54	n/a
			Unconstrained Grid Charging	Case 4: 2R, UnGC	2,939.02	(119.99)	2,819.04	9.00
				Case 5: 1R, UnGC	3,245.51	(659.13)	2,586.38	n/a
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	2,933.04	(197.75)	2,735.29	4.29
				Case 7: 1R, NoGC	3,223.37	(600.60)	2,622.77	n/a
			Unconstrained Grid Charging	Case 8: 2R, UnGC	2,942.13	(204.94)	2,737.20	7.27
				Case 9: 1R, UnGC	3,270.86	(719.27)	2,551.59	n/a
Low VER, July	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	2,671.95	(198.66)	2,473.30	6.65
				Case 3: 1R, NoGC	2,657.21	(338.23)	2,318.98	n/a
			Unconstrained Grid Charging	Case 4: 2R, UnGC	2,721.60	(145.67)	2,575.94	10.61
				Case 5: 1R, UnGC	2,566.81	(237.95)	2,328.86	n/a
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	2,676.81	(296.03)	2,380.78	4.46
				Case 7: 1R, NoGC	2,641.98	(362.76)	2,279.22	n/a
			Unconstrained Grid Charging	Case 8: 2R, UnGC	2,725.38	(336.82)	2,388.56	3.82
				Case 9: 1R, UnGC	2,569.35	(268.67)	2,300.68	n/a
High VER, April	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	1,546.85	(143.92)	1,402.93	5.27
				Case 12: 1R, UnGC	1,836.70	(503.97)	1,332.73	n/a
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	1,545.26	(137.77)	1,407.49	-0.77
				Case 14: 1R, UnGC	1,835.05	(416.65)	1,418.41	n/a
High VER, July	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	13,238.84	(247.71)	12,991.14	3.72
				Case 12: 1R, UnGC	13,019.23	(493.81)	12,525.42	n/a
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	13,247.32	(539.36)	12,707.96	1.69
				Case 14: 1R, UnGC	12,990.87	(494.00)	12,496.88	n/a

As an example, the above discussion is further demonstrated in
Figure 4 in the context of a single wind hybrid facility in Area E (i.e., New York Control Area Load Zone E – Mohawk Valley) for the July simulation period for the low VER penetration scenario. Only the UnGC case scenario under the *SF real-time operational strategy* was demonstrated for the sake of simplicity and ease of understanding. The plots on the left correspond to the *2R ISO-Managed Co-located Participation* option, whereas the plots on the right correspond to the *1R Self-Managed Hybrid Participation* option.

Figure 4(a) illustrates the day-ahead schedules, actual output in real-time, and minimum and maximum dispatch limits for the wind hybrid facility in Area E for both the 2R (left) and 1R (right) participation options under the SF real-time operational strategy. Analogously,
Figure 4(b) illustrates the day-ahead forecast and actual realization for the wind component of the hybrid facility.
Figure 4(c) illustrates the day-ahead schedules, actual output in real-time, maximum charge, and discharge limits for the storage component of the hybrid facility.
Figure 4(d) shows the stored energy level of the storage component in the day-ahead and real-time scheduling stages, and the minimum and maximum SoC limits for the storage component of the hybrid facility; and
Figure 4(e) the day-ahead and real-time market clearing prices at the location of the hybrid facility.

As mentioned before, in July, under the *SF real-time operational plan*, the 1R option usually results in lower day-ahead revenues than the 2R option since the cleared day-ahead hybrid resource schedules are generally lower with the economics of the developed bidding strategies when compared to the 2R cases that explicitly consider SoC. This can be confirmed from
Figure 4(a) as well. Moreover, the hybrid facility is then also required to buy back much of the energy that it cannot provide in real time due to SoC restrictions or VER forecast errors, typically at real-time LMPs that are greater than the LMP that was paid in the DAM. This can be confirmed from
Figure 4(c) and
Figure 4(d), which shows that the ESR component under the 1R option was unable to follow its day-ahead schedule in several real-time intervals due to infeasible day-ahead schedules resulting from the bidding strategies. This is also evident from the SoC levels observed in the day-ahead stage that were outside the feasible bounds, indicating that there is a greater likelihood for SoC violations under the 1R option. Finally, it can also be confirmed from
Figure 4(e) that the buybacks of much of the energy that the hybrid facility could not provide in real time due to SoC restrictions or VER forecast errors was mostly at real-time LMPs that were greater than the LMP that was paid in the DAM. Hence, for this hybrid facility, the short-run profits under the 2R option are greater than the 1R option.

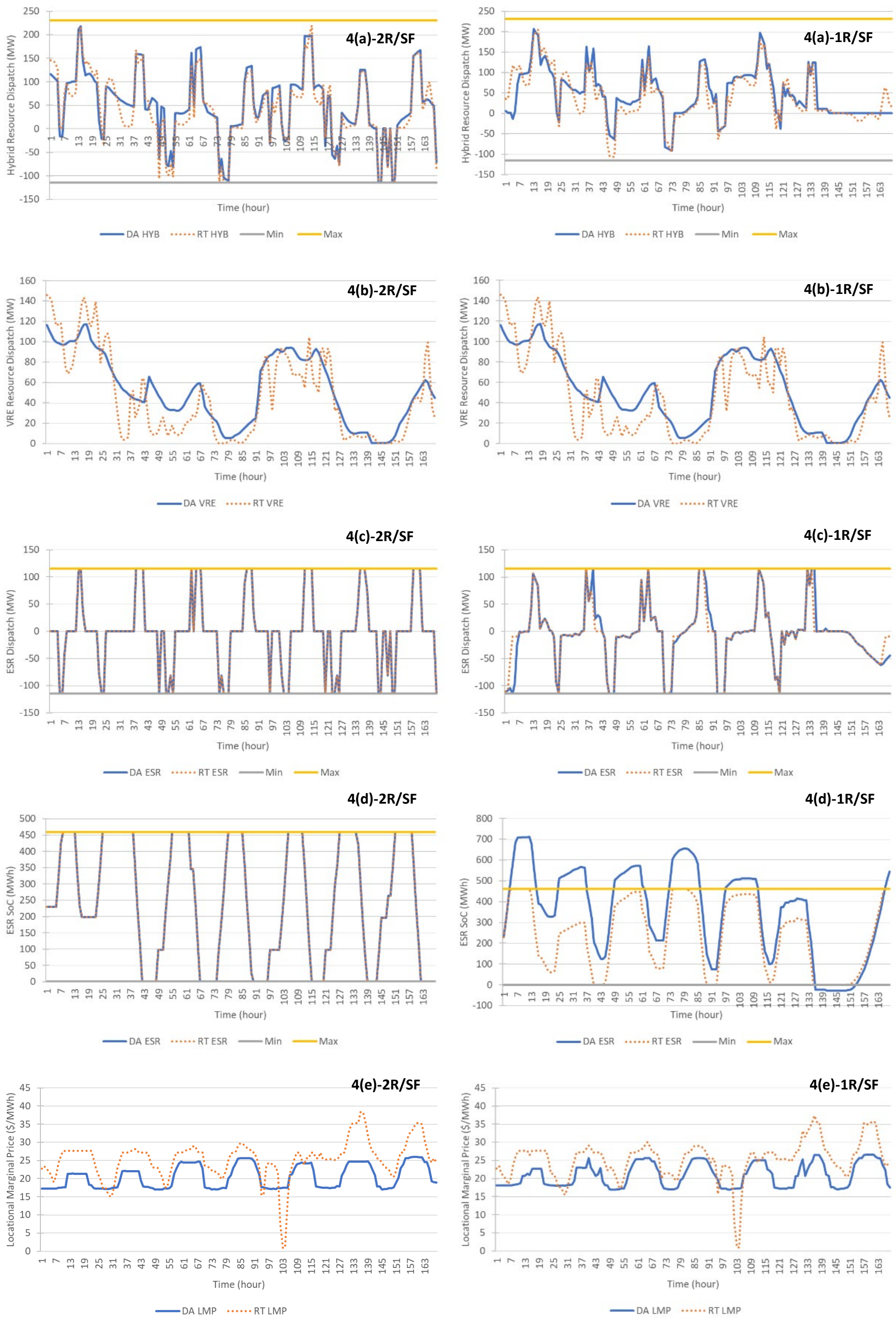


Figure 4. Area E wind hybrid facility for the low VER, July simulation period (one sample week), UnGC option, 2R/SF (left) and 1R/SF (right): (a) Hybrid resource dispatch, (b) VER dispatch, (c) ESR dispatch, (d) ESR SoC level, (e) LMP.

In a similar fashion, Figure 5 demonstrates the scheduled dispatch of a single solar hybrid facility in Area J (i.e., New York Control Area Load Zone J – New York City), in addition to the solar component dispatch, ESR component dispatch, ESR stored energy level, and market clearing prices at the location of the solar hybrid facility for both the day-ahead and real-time stages. This information pertains to the July simulation period for the high VER penetration scenario. Only the UnGC case scenario under the *HB real-time operational strategy* was demonstrated for the sake of simplicity and ease of understanding. The plots on the left correspond to the *2R ISO-Managed Co-located Participation* option, whereas the plots on the right correspond to the *1R Self-Managed Hybrid Participation* option.

In July, analogous to the SF real-time operational strategy, the 1R option usually generates lower day-ahead revenues compared to the 2R option in the *HB real-time operational plan*. This is because the cleared day-ahead hybrid resource schedules in the 1R cases are generally lower with the economics of the developed bidding strategies when compared to the 2R cases that explicitly consider SoC. Moreover, the hybrid facility is then also required to buy back much of the energy that it cannot provide in real time due to SoC restrictions or VER forecast errors, typically at real-time LMPs that are greater than the LMP that was paid in the DAM. However, as previously mentioned, it is expected that the *HB real-time operational strategy* can potentially result in comparable or greater real-time buybacks for the 2R option in some cases. This can be confirmed from Figure 5(a), which shows that the solar hybrid facility under the 2R option was unable to follow its day-ahead schedule in several real-time intervals (refer to hours 7-13 and hours 65-70), whereas the 1R option had fewer such occurrences. This is due to the ESR component's SoC running unpredictably low or high from trying to balance out forecast errors from the solar component in a previous interval under the HB operational strategy. This can be seen in (d), where the real-time SoC under the 2R option unpredictably runs low in hours 65 through 67 from trying to balance out forecast errors from the solar component in previous intervals. It can also be seen from Figure 5(c) that the storage component of this specific solar hybrid facility had significant real-time deviations to balance the solar forecast errors under both the 1R and 2R options for the HB real-time operational strategy. It can also be confirmed from Figure 5(e) that the buybacks of much of the energy that the hybrid facility could not provide in real time due to SoC restrictions or VER forecast errors was mostly at real-time LMPs that were greater than the LMP that was paid in the DAM.

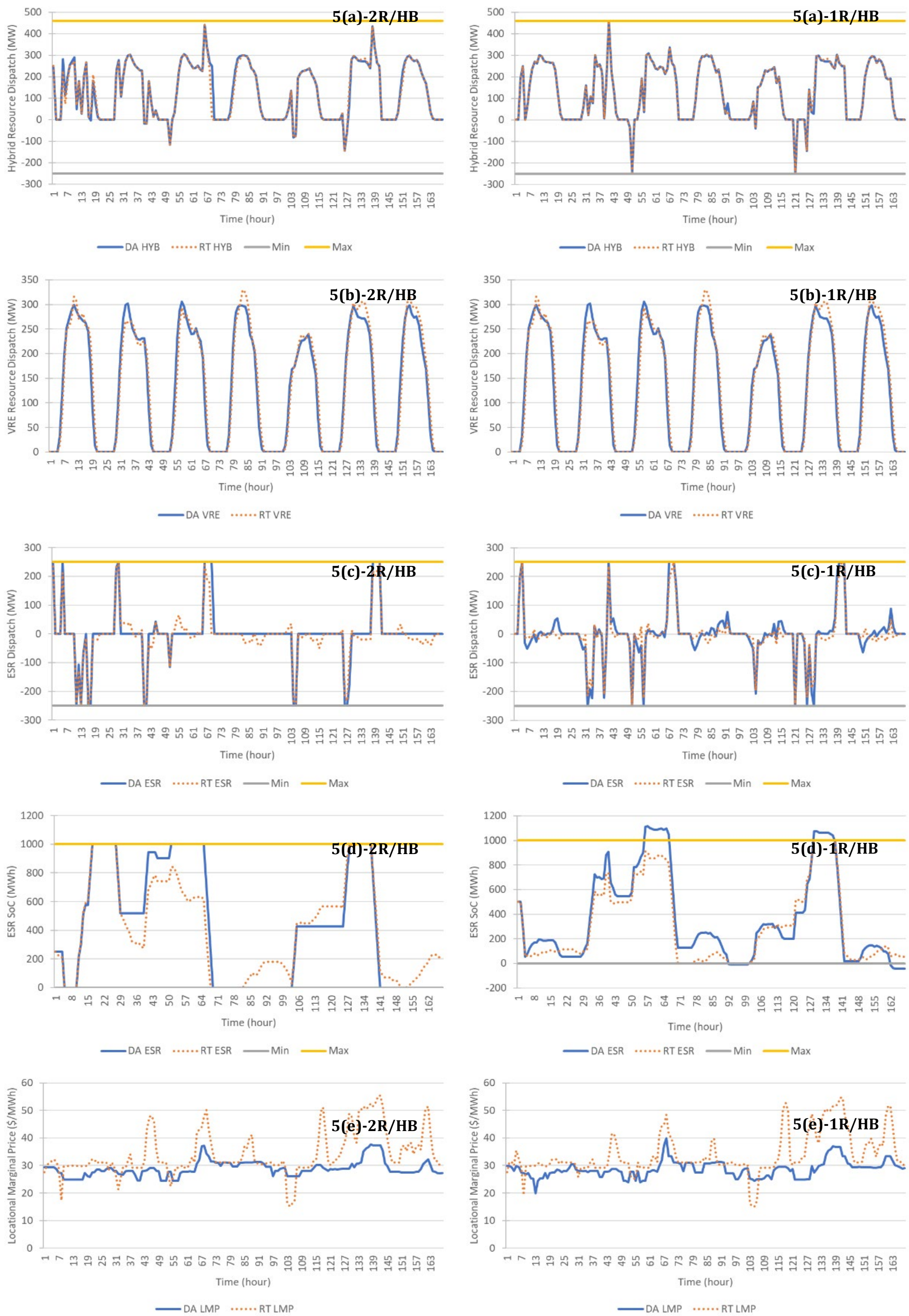


Figure 5. Area J solar hybrid facility for the high VER, July simulation period (one sample week), UnGC option, 2R/HB (left) and 1R/HB (right): (a) Hybrid resource dispatch, (b) VER dispatch, (c) ESR dispatch, (d) ESR SoC level, (e) LMP.

Third, negative (or imbalance) payments were observed in all the cases in real time. There can be specific situations that can result in such imbalance payments in real time. For instance, the SF real-time operational strategy will have an imbalance payment in any period that has a renewable forecast error from the VER component. Alternately, the HB real-time operational strategy will have an imbalance payment in a period when the storage component's SoC unexpectedly runs low or high from trying to balance out renewable forecast errors earlier in time. Moreover, both SF and HB operational strategies for the 1R self-managed hybrid participation option will have imbalance payments from any infeasible day-ahead schedules. This is also evident from the real-time revenue results summarized in Table 8. It was also observed that the imbalance payments are generally higher in the HB real-time operational strategy when compared to the SF real-time operational strategy, owing to the nature of its design structure. Consequently, as evident from the short-run profit results detailed above, the SF real-time operational strategy generally results in greater two-settlement profits when compared to the HB real-time operational strategy.

Fourth, in the April simulation period, the absolute difference in two-settlement profits (in $) between the 2R and 1R participation options is higher for scenarios with low VER penetration, compared to scenarios with high VER penetration. However, in the July simulation period the opposite trend was observed, where the absolute difference in two-settlement profits (in $) between the 2R and 1R participation options is higher for scenarios with high VER penetration compared to scenarios with low VER penetration. To put it simply, in this particular test case, during low load conditions like those in April, using the 2R option led to more significant differences in profits in the short term (with the current resource mix), compared to the future resource mix with higher levels of renewable and hybrid resources. This can be attributed to the lower energy prices expected in future power systems with a greater share of zero marginal cost resources and marginal cost pricing, which then impacts revenue and profit results. This is particularly the case for low load conditions observed in April. However, during peak load conditions like those in July, using the 2R option led to more significant differences in profits in the future resource mix with higher penetration of VER and hybrids compared to the current resource mix with fewer renewables and hybrids. This is because, in this test case, for scenarios with low VER and hybrid penetration, hybrids were not utilized as much during peak load conditions in July despite being economical since there is a greater need to have other more traditional resources online and producing at minimum generation levels to be able to meet the peak demand or ramping needs in future intervals of the optimization horizon. The low utilization of hybrids then impacts revenue and profits. Additionally, for scenarios with high VER and hybrid penetration, the peak load conditions in July resulted in higher energy prices than the low load conditions in April, which then impacted revenue and profits. It is important to note that these results depend on the specific resource mix and how hybrid resources are utilized under different system conditions.

Finally, for the low VER penetration scenario, it was observed that the *2R ISO-Managed Co-located Participation* option (2R, UnGC) consistently resulted in greater short-run profits than the *2R ISO-Managed Linked Co-Located Participation* option (2R, NoGC) under both SF and HB real-time operational strategies for both the simulation periods of April and July. This potentially implies that it might be beneficial for the hybrid resource to opt for the former participation option. However, it is crucial to note that these results do not include any ITC benefits that may also be obtained from charging solely from the co-located VER in the *2R ISO-Managed Linked Co-Located Participation* option cases. A similar trend was observed for the *1R Self-Managed Hybrid Participation* option for the peak load simulation period of July under both SF and HB real-time operational strategies where the UnGC cases resulted in greater short-run profits than the NoGC cases; however, this trend does not hold true for the low load simulation period of April due to the aggressive hybrid resource bidding strategies, the absence of explicit SoC consideration in the market clearing software when determining the cleared day-ahead hybrid resource schedules, and greater buybacks of energy in real time for the UnGC cases when compared to the NoGC cases.

Hybrid resource capability to follow real-time operational strategy. This metric demonstrates the ability of hybrid resources to adhere to either the storage follow (SF) or the hybrid balance (HB) real-time operational strategies. It provides an indication of the feasibility of day-ahead dispatch schedules, i.e., for the storage component (under SF) and the hybrid facility (under HB), in real time while considering renewable component forecast errors and the physical restrictions for the storage and renewable components as well as the hybrid facility. As described earlier, the SF real-time operational strategy requires that the storage component of the hybrid resource follow its day-ahead storage schedule, regardless of the renewable component variation. Additionally, the HB real-time operational strategy requires that the hybrid resource follow its day-ahead hybrid schedule and use its storage component to balance out renewable component variation. These operational strategies are not always feasible to follow in real time due to the application of the physical and operating limitations of the child components (e.g., minimum and maximum SoC restrictions, minimum and maximum charge and discharge restrictions, efficiency losses, minimum and maximum generation limits) and the parent hybrid resource (e.g., facility inverter limit). Hence, feasibility is observed through whether a violation of the real-time operational plan under consideration occurs due to any of the following reasons:

1. **The storage component has *insufficient discharge capacity* and cannot increase power output.** This suggested metric counts the number of intervals that are limited by insufficient discharge capacity. In other words, this metric counts the number of intervals in which storage is unable to follow its real-time operational strategy due to a physical restriction that has to do with its maximum discharge limit. Overcast error from the renewable component may result in the storage component having insufficient discharge capacity to further increase power output to balance out the renewable variation, leading to a violation of the real-time operational strategy. For instance, as shown in Figure 6(a), at hour 29 in July, the hybrid facility in Area J had a day-ahead dispatch schedule of 250.85 MW (i.e., 25.85 MW from the VER component and 225 MW from the ESR component). A lower VER component realization of 16.36 MW meant that storage component needed to increase its real-time dispatch to 234.49 MW to adhere to the HB real-time operational plan, i.e., that the hybrid facility follows its day-ahead schedule. However, the storage component had a maximum discharge limit of 225 MW and could not increase its power output, resulting in a violation of the HB real-time operational plan.
2. **The storage component has *insufficient charge capacity* and cannot decrease power output.** This suggested metric counts the number of intervals that are limited by insufficient charge capacity. In other words, this metric counts the number of intervals in which storage is unable to follow its real-time operational strategy due to a physical restriction that has to do with its

maximum charge limit. An under forecast error from the renewable component may result in the storage component having insufficient charge capacity to further decrease power output to balance out the renewable variation, leading to a violation of the real-time operational strategy. For instance, as shown in Figure 6(b), at hour 11 in July, the hybrid facility in Area J had a day-ahead dispatch schedule of 67.82 MW (i.e., 292.82 MW generation from the VER component and -225 MW charging from the ESR component). A higher VER component realization of 308.90 MW meant that storage component needed to increase its real-time consumption to -241.08 MW to adhere to the HB real-time operational plan, i.e., that the hybrid facility follows its day-ahead schedule. However, the storage component had a maximum charge limit of -225 MW and could not decrease its power output (or increase its power consumption), resulting in a violation of the HB real-time operational plan.

3. **The storage component has *insufficient SoC* or no available energy and cannot increase power output.** This suggested metric counts the number of intervals that are limited by insufficient SoC. In other words, this metric counts the number of intervals in which storage is unable to follow its real-time operational strategy due to a physical restriction that has to do with its minimum SoC limit or minimum level of stored energy. Forecast error from the renewable component or infeasible day-ahead schedules may result in the storage component having insufficient SoC to further increase power output to balance out the renewable variation (under HB) or to continue discharging and follow its day-ahead storage schedule (under SF), leading to a violation of the real-time operational strategy. For instance, as shown in Figure 6(c), at hour 39 in July, the storage component of a hybrid facility in Area E (i.e., modeled using the 1R option) had 318.80 MWh of stored energy in the DAM and a day-ahead dispatch schedule of 115 MW. However, the day-ahead dispatch schedule was infeasible to begin with, given that SoC is not considered in this option. The SF real-time operational strategy requires that storage continues to dispatch 115 MW in real time as well. However, due to the RTM respecting SoC limitations, there was only 52.19 MWh of stored energy left in the battery at hour 39 based on the real-time dispatch from prior intervals. Hence, the stored energy level was only able to allow for a maximum dispatch or discharge of 52.19 MW in real time due to insufficient SoC, resulting in a violation of the SF real-time operational strategy.
4. **The storage component has *maxed out SoC* or no available storage and cannot decrease power output.** This suggested metric counts the number of intervals that are limited by maximum SoC. In other words, this metric counts the number of intervals in which storage is unable to follow its real-time operational strategy due to a physical restriction that has to do with its maximum SoC limit or maximum level of stored energy. Forecast error from the renewable component or infeasible day-ahead schedules may result in the storage component having no available storage to further increase consumption to balance out the renewable variation (under HB) or to continue charging and follow its day-ahead storage schedule (under SF), leading to a violation of the real-time operational strategy. For instance, as shown in Figure 6(d), at hour 3 in July, the storage component of a hybrid facility in Area E (i.e., modeled using the 1R option) had 416.85 MWh of stored energy and a day-ahead dispatch schedule of -104.58 MW, which resulted in the stored energy level increasing to 505.74 MWh with 85% charging efficiency. However, the day-ahead dispatch schedule is infeasible to begin with, given that the

maximum SoC limit is 460 MWh but is not imposed as a constraint under this participation option. Now, the SF real-time operational strategy requires that the storage component continue to charge -104.58 MW in real time as well. However, due to the RTM respecting SoC limitations, there was only 43.15 MWh of available storage left in the battery at hour 3. Hence, the available storage level was only able to allow for a maximum consumption or charge of -50.76 MW in real time, while accounting for charging efficiency due to the maxed out SoC, resulting in a violation of the SF real-time operational strategy.

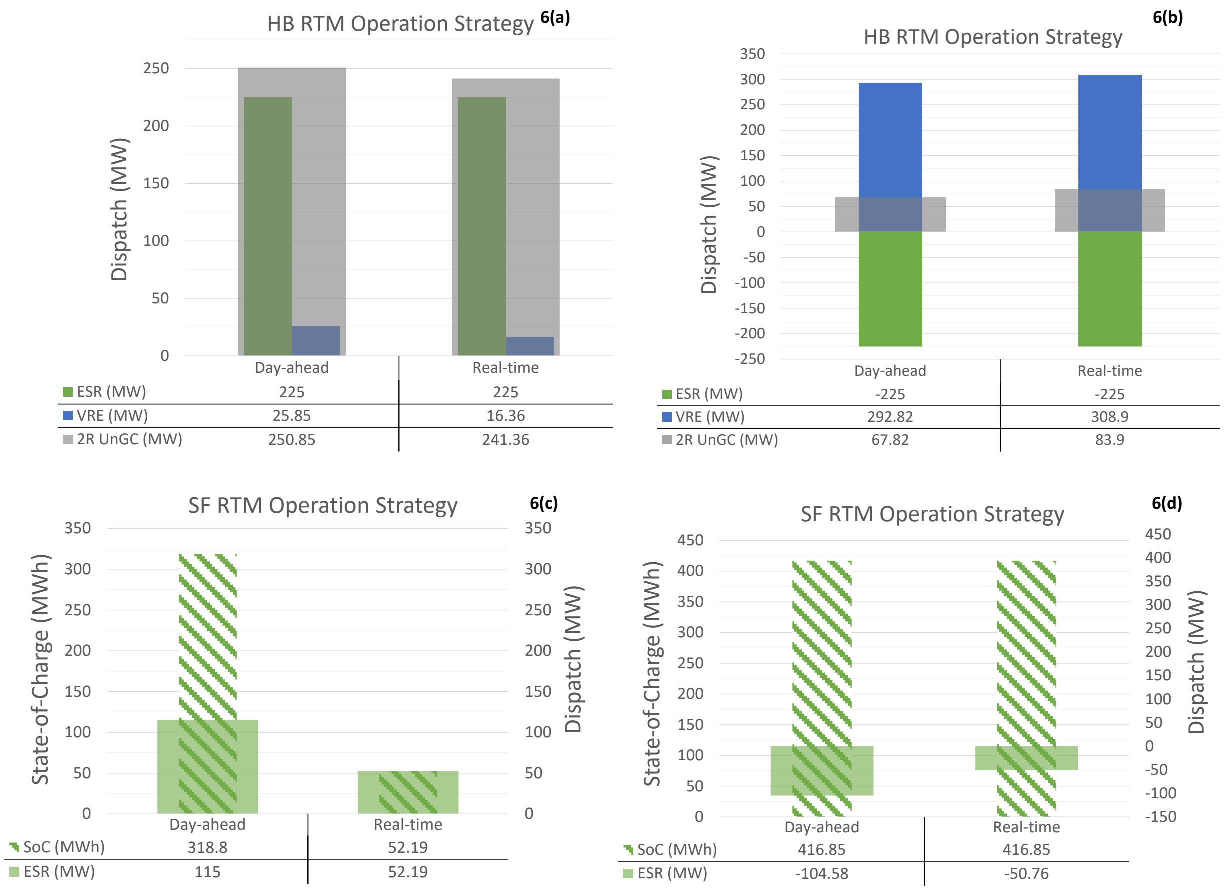


Figure 6. Illustration of violation of real-time operational plan under consideration: (a) Storage constituent of Area J hybrid facility has insufficient discharge capacity under 2R/HB option, (b) Storage constituent of Area J hybrid facility has insufficient charge capacity under 2R/HB option, (c) Storage constituent of Area E hybrid facility has insufficient SoC capacity under 1R/SF option, (d) Storage constituent of Area E hybrid facility has maxed out SoC capacity under 1R/SF option.

These four metrics can help anticipate how well a hybrid resource will be able to meet the needs of the system in real time. Table 9 summarizes the simulation results that demonstrate the ability of hybrid resources to adhere to either the SF or the HB real-time operational strategies. It is crucial to note that while violations of physical parameters of the storage component (e.g., minimum, and maximum SoC) and hybrid resource (e.g., interconnection limit) are not present in the results detailed below, their enforcement may lead to a real-time plan that does not follow the desired strategy, i.e., SF or HB. For instance, there may be occurrences where the storage component has an infeasible day-ahead schedule in real time under SF due to a combination of the VER component forecast error and the hybrid resource interconnection limitation. In such cases, if the storage component were to follow its day-ahead storage schedule exactly, the interconnection constraint would be violated. Given the established preferred violation sequence in the market clearing software, where the priority is to first violate the storage real-time operational plan, the interconnection constraint is always met in the said situation.

Furthermore, temporal coupling of the stored energy in the storage component due to the SoC constraint may exacerbate the count of the intervals that are limited from charging or discharging due to the physical restrictions mentioned above. For instance, the *1R Self-Managed Hybrid Participation* option that does not consider SoC and instead uses bidding strategies may result in a day-ahead schedule that consistently schedules the hybrid facility to charge in the early morning hours. However, as mentioned in the example above, in real time, upon reaching the maximum stored energy limit in hour 3 in July, the storage component of the hybrid facility in Area E was no longer able to continue charging, resulting in a violation of the SF real-time operational strategy in subsequent real-time intervals.

Additionally, there may be occurrences where the intervals limited by insufficient discharge capacity coincide with the intervals limited by insufficient SoC, or where the intervals limited by insufficient charge capacity coincide with the intervals limited by maximum SoC restrictions. For instance, at hour 6 in July, the hybrid facility in Area E had a day-ahead dispatch schedule of -16.48 MW (i.e., 98.52 MW generation from the VER component and -115 MW charging from the ESR component). A higher VER component realization of 117.48 MW meant that the storage component needed to increase its real-time consumption to -133.96 MW to adhere to the HB real-time operational plan, i.e., the hybrid facility follows its day-ahead schedule. However, the storage component had a maximum charge limit of -115 MW and could not further decrease its power output (or increase its power consumption), which indicates an instance of insufficient charge capacity. Additionally, at hour 6 in real time, the storage component had a stored energy level of 431.72 MWh and a maximum SoC limit of 460 MWh, which imposed additional restrictions on how much power the storage component could consume that was then limited to -33.27 MW, indicating an instance of maxed out SoC. The results detailed below avoid such instances of double counting by only including such occurrences either in the count of the intervals limited by insufficient charge capacity or in the count of the intervals limited by maxed out SoC, but not both.

Table 9. Hybrid resource capability to follow real-time operational strategy

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Intervals limited by insufficient discharge capacity (#)	Intervals limited by insufficient charge capacity (#)	Intervals limited by insufficient SoC (#)	Intervals limited by Max SoC (#)
Low VER, April	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	0	0	39	0
				Case 3: 1R, NoGC	0	0	865	102
			Unconstrained Grid Charging	Case 4: 2R, UnGC	0	0	28	3
				Case 5: 1R, UnGC	0	0	999	64
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	37	38	757	327
				Case 7: 1R, NoGC	22	11	930	262
			Unconstrained Grid Charging	Case 8: 2R, UnGC	33	66	880	311
				Case 9: 1R, UnGC	41	23	1224	171
Low VER, July	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	0	0	235	2
				Case 3: 1R, NoGC	0	0	684	573
			Unconstrained Grid Charging	Case 4: 2R, UnGC	0	0	73	48
				Case 5: 1R, UnGC	0	0	733	1044
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	149	75	652	434
				Case 7: 1R, NoGC	93	60	741	742
			Unconstrained Grid Charging	Case 8: 2R, UnGC	241	252	908	397
				Case 9: 1R, UnGC	170	203	920	809
High VER, April	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	0	0	130	31
				Case 12: 1R, UnGC	0	0	690	3347
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	150	314	1270	320
				Case 14: 1R, UnGC	58	128	564	3110
High VER, July	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	0	0	155	22
				Case 12: 1R, UnGC	0	0	600	623
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	166	240	1082	571
				Case 14: 1R, UnGC	125	129	871	724

A few interpretations can be made from the SoC feasibility results detailed in Table 9. First, in both April and July simulation periods, as well as in scenarios with both low and high VER penetration, the SF real-time operational strategy consistently led to no intervals where there is insufficient capacity for discharge or charge in both the 1R and 2R participation options. This result is expected for the 2R option since the modeling assumptions in this option ensured that maximum discharge and maximum charge restrictions for both the storage component as well as the hybrid facility were respected at all stages of the market simulations, but several factors contributed to this outcome for the 1R option. The *1R Self-Managed Hybrid Participation* option did not consider SoC restrictions in the DAM. Instead, it relied on bidding strategies that are restricted by the maximum discharge and maximum charge limitations of the hybrid facility in both the day-ahead and real-time stages. Additionally, to implement the 1R option within the market clearing software, the team used a pseudo-2R modeling approach that involves representing both the child injectors to be able to monitor the SoC of the child storage resource and accordingly update the bids each day. This pseudo-2R modeling approach was incorporated into both the DAM and the RTM, ensuring that the maximum discharge and maximum charge restrictions of the storage component were also respected in both the stages. Moreover, when developing bidding strategies for DA participation under the 1R option, both the maximum charge and maximum discharge capacity limitations for the individual components and the hybrid facility were taken into account. Thus, for reasons mentioned above, it is expected that there will be no real-time intervals where charge and discharge capacity is insufficient under the SF real-time operational strategy for the 1R option since the storage component simply follows its day-ahead schedule, which already respected these limitations.

However, intervals limited by insufficient SoC or max SoC may still exist under the SF real-time operational plan. Alternately, forecast error from the VER component, or a day-ahead dispatch schedule that is based on bidding strategies that is infeasible to follow in real time could potentially result in intervals with insufficient or max SoC. For instance, the *1R Self-Managed Hybrid Participation* option that does not consider SoC and instead uses bidding strategies may result in a day-ahead schedule that consistently schedules the hybrid facility to charge in the early morning hours. However, in real time, upon reaching the maximum stored energy limit in hour 3 in July, the storage component of the hybrid facility in Area E was no longer able to continue charging, resulting in a violation of the SF real-time operational strategy in subsequent real-time intervals. Such occurrences count as intervals limited by max SoC. Analogously, there can also be similar intervals where the storage component is no longer able to continue to discharge due to insufficient SoC, resulting in a violation of the SF real-time operational plan.

Second, for both April and July simulation periods, and for both low and high VER penetration scenarios, the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option appear to have consistently performed significantly better than the *1R Self-Managed Hybrid Participation* option under the SF real-time operational strategy. For instance, for the low VER penetration, NoGC option, the April simulation period case scenario under the SF real-time operational plan, the 2R linked option registered 39 intervals with insufficient SoC compared to the 1R option, with 865 intervals of insufficient SoC. The number of intervals that are limited by insufficient

SoC or maxed out SoC are consistently lower in the 2R options than in the 1R option since SoC feasibility is explicitly considered in the DAM for the 2R options.

In the case of the 2R options, forecast error of the VER component may result in deviations from the day-ahead storage schedule in one real-time interval that then impacts its ability to adhere to the SF real-time operational strategy in subsequent intervals due to the temporal coupling of the stored energy. For instance, in hour 421 in July, as shown in Figure 7(b), the VER component of a hybrid facility in Area E had an increase in its real-time realization to 145.87 MW from its day-ahead forecast of 115.66 MW. This restricted the storage component from following its day-ahead dispatch schedule of 115 MW in real time and instead only allowed for a discharge of 85.13 MW (see Figure 7(c)) to respect the hybrid inverter limit of 231 MW (as shown in Figure 7(a)). Such a deviation in the storage real-time schedule implies that its stored energy levels differ between the day-ahead and real time scheduling stages, which in this case resulted in a subsequent interval being limited by its maximum SoC. For the same hybrid facility, in hour 438 in July, the storage component had a dispatch of -115 MW in day-ahead but was only able to dispatch -23.94 MW in real time (as shown in Figure 7(c)) due to being limited by its maximum SoC (see Figure 7(d)). Moreover, in contrast to the 2R options, the 1R option lacks the ability to adapt the charge or discharge schedule of the storage component based on SoC considerations. This is because the 1R option does not account for SoC limitations explicitly and instead establishes the day-ahead dispatch schedules based on the developed bidding strategies, which results in an infeasible real-time dispatch schedule. Hence, overall, the 1R participation option registers an increased count of intervals that are limited by insufficient SoC or maximum SoC under the SF real-time operational strategy.

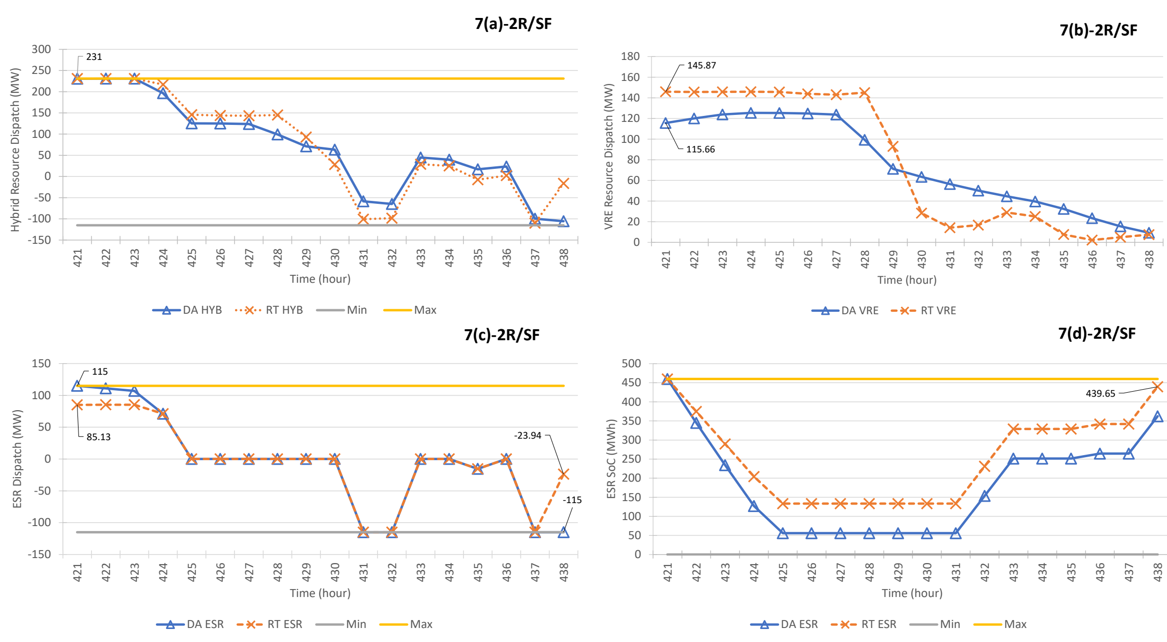


Figure 7. Illustration of the inability of an Area E hybrid facility to adhere to the SF real-time operational strategies under the 2R option: (a) Hybrid resource dispatch, (b) VER dispatch, (c) ESR dispatch, (d) ESR SoC level.

Third, for the low VER penetration scenario, for both April and July simulation periods, under the SF real-time operational strategy, the *2R ISO-Managed Co-located Participation* option (2R, UnGC) seems to perform better than the *2R ISO-Managed Linked Co-Located Participation* option (2R, NoGC) with a lower count of intervals limited by insufficient SoC. For example, 2R, UnGC registered 73 intervals limited by insufficient SoC compared to 235 for 2R, NoGC. Now, since the storage component in the NoGC cases charges solely from the VER component, forecast error from the VER component results in deviations in the stored energy levels of the storage component. The mismatch of stored energy levels in the day-ahead and real-time scheduling stages contributes to the higher number of intervals limited by insufficient SoC. For instance, for a hybrid facility in Area E, lower VER realizations in multiple real-time intervals between hours 45 and 78 in July, when compared to the day-ahead forecasts combined with the restriction to disallow grid charging, resulted in reduced stored energy levels in the storage component during the corresponding hours in real time. This eventually resulted in the storage component not being able to follow its day-ahead dispatch schedule of 115 MW in hour 86 in real time and instead only discharging 62.5 MW because it was limited by insufficient SoC. On the contrary, the *1R Self-Managed Hybrid Participation* option exhibited an opposite trend, with a higher count of intervals limited by insufficient SoC for the UnGC option compared to the NoGC option for the low VER penetration scenario, for both April and July simulation periods, under the SF real-time operational strategy. In the 1R option, when the storage component has the flexibility to charge from the grid (i.e., the unconstrained grid charging option: 1R, UnGC), it often schedules relatively more aggressively in the DAM with a greater number of intervals cleared at maximum charging or maximum discharging dispatch limits when compared to the no grid charging option (1R, NoGC). This results in excessive replenishment or depletion of the stored energy in the storage component at the day-ahead stage that becomes infeasible to follow in the real-time stage due to the SoC restrictions being respected in real time. Alternatively, when the storage component does not have the flexibility to charge from the grid (i.e., the no grid charging option: 1R, NoGC), it is not dispatched at maximum charge or maximum discharge dispatch limits as often. This is due to its complete dependence on renewable generation, which results in a reduced number of intervals that are limited by insufficient SoC.

Fourth, contrary to the SF real-time operational strategy, the HB real-time operational strategy results in non-zero intervals that are limited by insufficient discharge capacity or insufficient charge capacity for both the 1R and 2R participation options for both April and July simulation periods and for both low and high VER penetration scenarios. Under the HB real-time operational strategy, there can be occurrences of forecast error from the VER component of the hybrid facility that can result in an infeasible real-time deviation for the storage component from its day-ahead dispatch schedule (i.e., due to its maximum discharge capacity or maximum charge capacity restrictions) if it were to adhere to the hybrid resource day-ahead schedule. For instance, at hour 29 in July, the hybrid facility in Area J had a day-ahead dispatch schedule of 250.85 MW (i.e., 25.85 MW generation from the VER component and 225 MW discharge from the ESR component). A lower VER component realization of 16.36 MW meant that the storage component needed to increase its real-time dispatch to 234.49 MW to adhere to the HB real-time operational strategy, i.e., the hybrid facility follows its day-ahead schedule. However, storage had a maximum discharge limit of 225 MW and could not further increase its power output.

This resulted in a violation of the HB real-time operational plan and indicates an instance of insufficient discharge capacity.

Furthermore, in the HB real-time operational strategy, there are occurrences where the intervals are limited by both insufficient charge capacity and maximum SoC simultaneously. However, as stated before, the results included in this subsection avoid such instances of double counting by only including such occurrences either in the count of the intervals limited by insufficient charge capacity or in the count of the intervals limited by maxed out SoC, but not both. Table 10 summarizes the simulation results that demonstrate the ability of hybrid resources to adhere to either the SF or the HB real-time operational strategies on a *cumulative* basis. In this context, real-time feasibility is observed through the following metrics that are calculated on a cumulative basis.

1. **The storage component has insufficient discharge capacity and/or insufficient SoC and cannot increase power output.** This suggested metric counts the number of intervals (also referred to as *total discharge intervals*) in which storage is unable to follow its real-time operational strategy due to its physical restrictions that have to do with either its maximum discharge limit or its minimum SoC limit.
2. **The storage component has insufficient charge capacity and/or max SoC and cannot decrease its power output.** This suggested metric counts the total number of intervals (also referred to as *total charge intervals*) in which storage is unable to follow its real-time operational strategy due to its physical restrictions that have to do with either its maximum charge limit or its maximum SoC limit.

Fifth, when comparing the cumulative count of intervals limited by insufficient discharge capacity, insufficient charge capacity, insufficient SoC capacity, and maximum SoC, it appears that the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option generally perform better than the *1R Self-Managed Hybrid Participation* option under the HB real-time operational plan for both April and July simulation periods for both low and high VER penetration scenarios. However, there is one exception: the high VER penetration in the July simulation period, where the 1R option performed better than the 2R option for HB. In general, if individual metrics are compared against each other across the different participation options, it is hard to predict which participation option may perform better under the HB real-time operational plan. This is due to its design and the temporal nature of the SoC constraint, where an action in one real-time interval can ripple through time and impact subsequent real-time intervals.

Finally, the HB real-time operational strategy generally tends to encounter a higher occurrence of limitations related to insufficient discharge capacity, insufficient charge capacity, insufficient SoC capacity, and maximum SoC on a cumulative basis compared to the corresponding SF real-time strategy. This observation holds true across all case scenarios, primarily due to the presence of a limited energy storage resource and the need for it to deviate from its day-ahead schedule to firm-up its co-located renewable component in real time under the HB operational strategy.

Table 10. Hybrid resource capability to follow real-time operational strategy on a cumulative basis

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Total discharge intervals (limited by insufficient discharge capacity & SoC) (#)	Total charge intervals (limited by insufficient charge capacity and Max SoC) (#)	Cumulative intervals limited by insufficient discharge, charge & SoC capacity & Max SoC (#)
Low VER, April	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	39	0	39
				Case 3: 1R, NoGC	865	102	967
			Unconstrained Grid Charging	Case 4: 2R, UnGC	28	3	31
				Case 5: 1R, UnGC	999	64	1063
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	794	365	1159
				Case 7: 1R, NoGC	952	273	1225
			Unconstrained Grid Charging	Case 8: 2R, UnGC	913	377	1290
				Case 9: 1R, UnGC	1265	194	1459
Low VER, July	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	235	2	237
				Case 3: 1R, NoGC	684	573	1257
			Unconstrained Grid Charging	Case 4: 2R, UnGC	73	48	121
				Case 5: 1R, UnGC	733	1044	1777
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	801	509	1310
				Case 7: 1R, NoGC	834	802	1636
			Unconstrained Grid Charging	Case 8: 2R, UnGC	1149	649	1798
				Case 9: 1R, UnGC	1090	1012	2102
High VER, April	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	130	31	161
				Case 12: 1R, UnGC	690	3347	4037
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	1420	634	2054
				Case 14: 1R, UnGC	622	3238	3860
High VER, July	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	155	22	177
				Case 12: 1R, UnGC	600	623	1223
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	1248	811	2059
				Case 14: 1R, UnGC	996	853	1849

Load payments. Energy is bought and sold in the ISO markets through a sequence of auctions differentiated by time. Each seller and buyer that clears the DAM receives an hourly schedule and is financially settled at market clearing prices at the locations where they transact. Any deviations from day-ahead schedules are settled in the RTM at the RTM price. In the United States ISO markets, the market clearing price for energy is referred to as the LMP, which is also typically known as the *nodal price.* Supplier LMPs are usually calculated at the points of connections of the suppliers or resources to the transmission system (i.e., at their nodes or points of injections). However, typically, aggregated LMPs are used for loads and are calculated using the load-weighted average corresponding to a zone that is generally defined by electrical or utility boundaries and is used to settle load. Although the practice of using aggregated locational prices for loads prevents excessive locational volatility to the loads, it might not incentivize load response adequately to avoid high prices during intra-zonal congestion. Accordingly, day-ahead load payment is calculated as the product of the day-ahead load quantity (in MW) per hour and the day-ahead LMP in its zone; real-time load payment is calculated as the product of the deviation from the day-ahead load schedules (in MW) per hour and the real-time LMP in its zone; and the two-settlement load payment is calculated as the sum of the day-ahead and real-time load payments.

Table 11 first provides the day-ahead and real-time load payments individually, and then provides the two-settlement load payment for the New York ISO footprint (NYISO FP) across the difference case scenarios. A few interpretations can be obtained from the systemwide load payment results, as detailed below. First, for this test system, given the absence of any power imbalances or reserve shortages that may impact the volatility of market clearing prices in real-time operations, a majority of the differences in the two-settlement load payments stem from the component that has to do with the day-ahead load payment. Since the day-ahead system load is much larger than the real-time deviations from the day-ahead load, any small difference in DAM clearing prices between different case scenarios can bring about major differences between the day-ahead load payments, which then impacts the two-settlement load payments more significantly than real-time load payments. This can be observed in Table 11 below as well. Consequently, this study deems it crucial to better understand the impact of the different participation options on price formation in future work.

Second, for the low-load April simulation period, the two-settlement load payment for the NYISO FP is consistently greater for the *2R ISO-Managed Co-located Participation* option (2R, UnGC) when compared to the *1R Self-Managed Hybrid Participation* option (1R, UnGC) under both SF and HB real-time operational strategies for both low and high VER penetration levels. Now, both the day-ahead load quantity per hour and the real-time deviations from the day-ahead load schedules per hour are each consistently the same across all the case scenarios for the April simulation period. This is true be it the base case, the 2R or 1R participation option cases, the SF or HB real-time operational strategies, or the low or high VER penetration cases. The only difference among these cases is the day-ahead and real-time NYISO FP load price, which is impacted by the choice of the participation modeling option. For instance, Figure 8 shows the day-ahead and real-time load price for the NYISO FP for the low VER, April simulation period, for the UnGC cases. For April, as mentioned before under profits and incentives, the cleared day-ahead hybrid resource schedules are generally higher for the 1R cases with the developed bidding strategies when compared to the 2R cases that explicitly consider SoC, which results in flatter day-ahead load prices for the 1R cases due to the energy shifting nature of the storage component. Consequently, the day-ahead load payments are consistently lower for the 1R cases, which reduces the two-settlement load payments significantly. The opposite is true for the real-time hybrid resource schedules and load prices for the 1R cases, since the hybrid facilities must buy back much of the energy that they cannot provide in real time due to SoC restrictions or for other reasons.

On the contrary, for the peak load July simulation period, the two-settlement load payment for the NYISO FP is generally lower for the *2R ISO-Managed Co-located Participation* option (2R, UnGC) when compared to the *1R Self-Managed Hybrid Participation* option (1R, UnGC) under both SF and HB real-time operational strategies for both low and high VER penetration levels. Both the day-ahead load quantity per hour and the real-time deviations from the day-ahead load schedules per hour are each consistently the same across all the case scenarios for the July simulation period. This is true be it the base case, the 2R or 1R participation option cases, the SF or HB real-time operational strategies, or the low or high VER penetration cases. The only difference among these cases is the day-ahead and real-time NYISO FP load price, which is impacted by the choice of the participation modeling option. For instance, Figure 9 shows the day-ahead and real-time load price for the NYISO FP for the low VER, July simulation period, for the UnGC cases. For July, as mentioned before under profits and incentives, the cleared day-ahead hybrid resource schedules are generally lower with the developed bidding strategies for the 1R cases when compared to the 2R cases that explicitly consider SoC. As a result of the lower cleared awards for hybrid facilities under the 1R option, the day-ahead load prices are less flat when compared to the 2R option. Consequently, the day-ahead load payments are higher for the 1R cases, which increases the two-settlement load payments.

Overall, the implications on the load payments are decidedly dependent on the cleared energy awards for the hybrid storage facilities that can differ based on the submitted bidding strategies or the explicit SoC consideration under the alternate participation options, since the cleared awards then impact the market clearing prices and the calculated load payments. This is observed when comparing the 2R and 1R participation options for the low VER, NoGC cases as well.

Third, as apparent, the two-settlement load payment for the low load April simulation period is consistently lower than the peak load July simulation period for both the low VER and the high VER penetration case scenarios individually. Regardless of the VER penetration levels, the peak demand conditions that the test system experiences in July requires additional supply resources (that are higher on the merit order stack of resources when compared to April) to be online and producing to balance the peak demand, which increases the market clearing prices and impacts the load payments. Lastly, the real-time load payment for the SF real-time operational strategy is mostly lower than the accompanying HB real-time operational strategy across the different case scenarios, but this really depends on the impact of the deviation of storage from its day-ahead schedule under the HB real-time operational strategy on the market clearing price at its location which for this test system seems to be generally increasing the RTM clearing prices more than SF.

Table 11. System-wide load payment results

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Day-ahead Load Payment ($M)	Real-time Load Payment Only ($M)	Two-settlement Load Payment ($M)
Low VER, April	No Hybrid	n/a	n/a	Case 1: Base	167.66	6.82	174.48
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	165.42	6.82	172.24
				Case 3: 1R, NoGC	166.06	6.83	172.89
			Unconstrained Grid Charging	Case 4: 2R, UnGC	165.73	6.76	172.48
				Case 5: 1R, UnGC	165.40	6.76	172.16
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	165.45	6.80	172.25
				Case 7: 1R, NoGC	166.10	6.76	172.86
			Unconstrained Grid Charging	Case 8: 2R, UnGC	165.97	6.82	172.79
				Case 9: 1R, UnGC	165.56	6.84	172.40
Low VER, July	No Hybrid	n/a	n/a	Case 1: Base	391.75	10.91	402.66
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	392.17	10.88	403.05
				Case 3: 1R, NoGC	391.96	10.87	402.84
			Unconstrained Grid Charging	Case 4: 2R, UnGC	391.05	10.86	401.91
				Case 5: 1R, UnGC	391.86	10.85	402.72
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	392.49	10.91	403.41
				Case 7: 1R, NoGC	392.09	10.91	403.00
			Unconstrained Grid Charging	Case 8: 2R, UnGC	391.17	10.91	402.09
				Case 9: 1R, UnGC	392.14	10.90	403.03
High VER, April	No Hybrid	n/a	n/a	Case 10: Base	37.74	2.08	39.82
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	37.68	2.01	39.68
			Unconstrained Grid Charging	Case 12: 1R, UnGC	36.97	2.05	39.02
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	37.66	2.09	39.75
			Unconstrained Grid Charging	Case 14: 1R, UnGC	36.95	2.05	39.00
High VER, July	No Hybrid	n/a	n/a	Case 10: Base	436.06	14.01	450.08
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	430.72	13.92	444.64
			Unconstrained Grid Charging	Case 12: 1R, UnGC	432.59	13.79	446.38
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	431.19	14.15	445.34
			Unconstrained Grid Charging	Case 14: 1R, UnGC	430.96	13.92	444.87

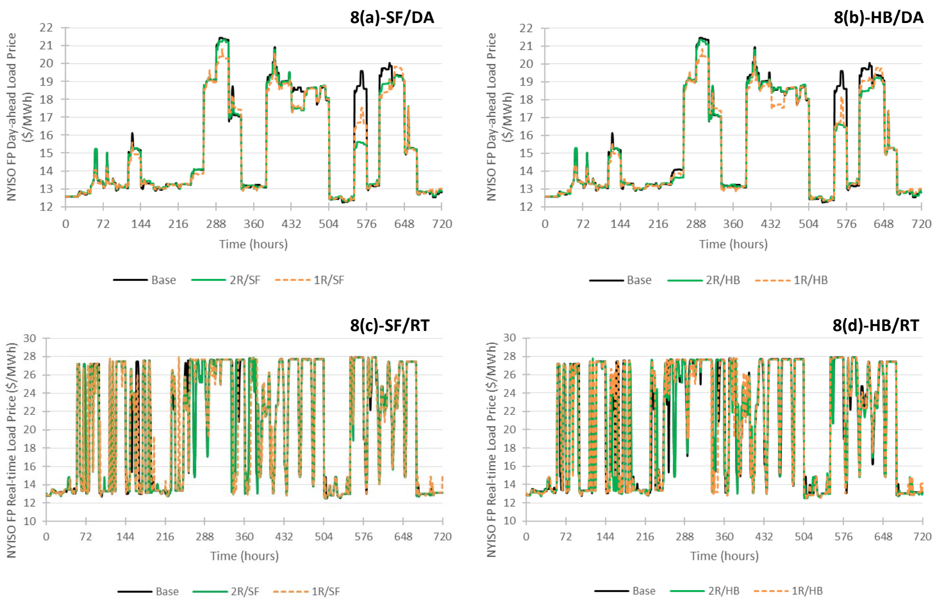


Figure 8. NYISO footprint load price ($/MWh) for the low VER, April simulation period, for the unconstrained grid charging option, under the SF operation strategy (left) and the HB operation strategy (right), for day-ahead (top) and real time (bottom).

Figure 9. NYISO footprint load price ($/MWh) for the low VER, July simulation period, for the unconstrained grid charging option, under the SF operational strategy (left) and the HB operational strategy (right), for day-ahead (top) and real time (bottom).

Computational efficiency. When introducing new modifications to the market clearing software, it is critical to assess what computational issues may result due to the introduced modifications. Table 12 summarizes the total solve time (in seconds) for the day-ahead and real-time scheduling stages of the market simulations across the different case scenarios. Solve time denotes the CPU time to solve the math problem, i.e., the DASCUC and RTSCUC problems. The total solve time is the summation of the solve time for all horizons in the simulation period, i.e., 30 days in April and 31 days in July, respectively. In general, it is expected that explicit modeling of the hour-to-hour chronology for the storage component of the hybrid facility under the *2R ISO-Managed Co-located* and *2R ISO-Managed Linked Co-Located* participation options will impact the computational efficiency of the DASCUC problem.

As anticipated, given the meticulous consideration of the SoC constraints in the DAM under the *2R ISO-Managed Co-located Participation* option (2R, UnGC) and the *2R ISO-Managed Linked Co-Located Participation* option (2R, NoGC), the total solve time is mostly greater than the *1R Self-Managed Hybrid Participation* option across the majority of the case scenarios for the different simulation periods, VER and hybrid penetration levels, real-time operational strategies, and grid charging restrictions. One exception to this wide-ranging result is the peak load simulation period in July for the high VER, high hybrid penetration level under the HB real-time operational strategy, where the day-ahead solve time for the *1R Self-Managed Hybrid Participation* option is greater than the *2R ISO-Managed Co-located Participation* option. In fact, this is the one counterintuitive case scenario where the base case without any hybrid resources results in the largest solve time for the DASCUC stage. Now, this is potentially possible especially under stressed system conditions such as the peak load conditions observed in July for a future resource mix with limited flexible resources, where interaction with other constraints such as unit commitment and inter-temporal ramp-rate constraints can potentially impact the feasibility space and consecutively the solve times unpredictably, so it is difficult to draw any conclusions as such. For all other VER penetration scenarios and simulation periods, as envisaged, the base case without any hybrid resources results in the lowest solve times for the DASCUC stage given fewer constraints and variables in the absence of hybrid facilities.

In general, the July simulation period has higher solve times when compared to the low load April simulation period for both low and high VER penetration levels. Furthermore, for the low VER penetration case scenarios, the day-ahead solve time for the NoGC cases are mostly greater than the UnGC cases for both 2R and 1R participation options under both SF and HB real-time operational strategies. Finally, since the RTM is structured in the same manner across the different participation options to conduct a fair comparison, the total solve times for the real-time stage are comparable, as presumed.

Table 12. Computational efficiency results

VER Penetration, Simulation Period	Hybrid Penetration	RTM Operation Strategy	Grid Charging Option	Case	Day-ahead Solve Time (seconds)	Real-time Solve Time (seconds)
Low VER, April	No Hybrid	n/a	n/a	Case 1: Base	164.70	32.34
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	184.94	34.26
				Case 3: 1R, NoGC	171.25	31.48
			Unconstrained Grid Charging	Case 4: 2R, UnGC	185.41	35.25
				Case 5: 1R, UnGC	162.96	31.78
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	192.32	36.70
				Case 7: 1R, NoGC	179.32	34.74
			Unconstrained Grid Charging	Case 8: 2R, UnGC	181.56	31.77
				Case 9: 1R, UnGC	172.59	36.33
Low VER, July	No Hybrid	n/a	n/a	Case 1: Base	242.79	37.12
	Low Hybrid	Storage Follow	No Grid Charging	Case 2: 2R, NoGC	304.28	44.73
				Case 3: 1R, NoGC	273.86	40.04
			Unconstrained Grid Charging	Case 4: 2R, UnGC	292.40	41.56
				Case 5: 1R, UnGC	261.84	42.68
		Hybrid Balance	No Grid Charging	Case 6: 2R, NoGC	302.59	43.44
				Case 7: 1R, NoGC	283.41	43.06
			Unconstrained Grid Charging	Case 8: 2R, UnGC	278.91	40.42
				Case 9: 1R, UnGC	264.12	39.99
High VER, April	No Hybrid	n/a	n/a	Case 10: Base	70.67	30.85
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	89.67	32.32
				Case 12: 1R, UnGC	87.32	32.43
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	94.99	41.43
				Case 14: 1R, UnGC	87.94	34.37
High VER, July	No Hybrid	n/a	n/a	Case 10: Base	596.73	37.70
	High Hybrid	Storage Follow	Unconstrained Grid Charging	Case 11: 2R, UnGC	516.83	45.44
				Case 12: 1R, UnGC	488.11	46.84
		Hybrid Balance	Unconstrained Grid Charging	Case 13: 2R, UnGC	523.08	50.29
				Case 14: 1R, UnGC	531.84	47.09

Overall, granular models such as the 2R participation options tend to provide theoretical efficiency gains, but they also add computational complexity to the market clearing software compared to the 1R participation model and may not be desired by all participants. This is evident from Table 12 above, where the granular models have resulted in greater DA solve times given that explicit SoC management adds complexity to the market clearing software.

It is anticipated that the participation of storage-based resources in electricity markets will dramatically increase in the near future but may not be able to scale with ideal market modeling under the 2R participation options due to computational limitations. Future work will investigate the computational efficiency implications of replacing the explicit modeling of hour-to-hour chronology under the 2R participation options with an implicit modeling of chronology through fewer wrapper constraints for storage. This will allow for massive integration of storage-based resources without adverse computational or reliability and economic impacts.

Other anticipated impacts of the proposed hybrid resource participation options such as price formation, price setting, market settlements, make-whole payments, and market mitigation are out of scope for this phase of the study and will potentially be examined in future research. Finally, it is important to be cognizant that if the location of hybrid storage resources on the test grid were to be modified, then it is likely to impact the results presented above, but the general comparative conclusions should still hold.

5. Conclusions and Future Work

System operators across North America are presently evaluating ways in which hybrid storage resources can participate in wholesale electricity markets. A resource's "participation model" encompasses various aspects, such as how the resource interacts with the market operator, its bidding and physical parameters, and how it is represented in the market clearing software. This project assessed the impacts of different hybrid storage resource participation models using realistic power market simulations to provide the industry with metrics that quantify their potential advantages and disadvantages. Thorough resource modeling was performed, with developments recognized on how to enhance the capability of state-of-the-art commercial-grade production cost modeling and market clearing software to better incorporate the proposed participation modeling options for hybrid storage resources.

Several software adaptations were suggested to enable running the market operations simulations effectively. Moreover, several case scenarios were run to evaluate the impact of detailed market participation modeling options for hybrid storage resources on economic efficiency (or system costs), system reliability, asset profits and incentives, hybrid resource capability to follow different real-time operational strategies, load payments, and computational efficiency under different system conditions. The system conditions that were examined in this study include different assumptions on system resource mixes (with differing penetrations of VER and hybrid storage resources), simulation periods (e.g., low load versus peak load), real-time operational strategies (such as storage follow or hybrid balance), and grid charging restrictions (i.e., unconstrained grid charging versus no grid charging). Comparative descriptions across different case scenarios were also provided at a high level for illustration, but it should be emphasized that different assumptions were made in each of the sensitivities, so the results are not directly comparable. Some of the key takeaways from this study are summarized below. It is worthwhile to note that the key takeaways are based on the assumptions mentioned in the report around the approach adopted to develop, implement, and incorporate the offer/bid curves in the market clearing software for the 1R option. They are for the realistic test system under consideration while focusing mostly on hybrid storage resource participation in the DAM without allowing for updates of offers in the RTM.

Economic efficiency. Granular models such as the 2R participation options generally provide greater savings in system operating costs. However, the magnitude of savings is contingent upon the system operating conditions under consideration, magnitude of forecast errors, resource mix, and potentially the location of the hybrid facilities as well. By explicitly incorporating SoC within the market clearing software, the 2R options enable a more efficient operation of the hybrid storage facilities. Moreover, the 2R participation option is better at scheduling the cheaper traditional resources (such as combined cycle plants) that require day-ahead start-up notification in the DAM while considering SoC feasibility of the storage component of the hybrid facilities, consequently, leading to lesser reliance on the more expensive resources (such as GTs and ICs) in real time. The dependence of the hybrid facilities on the developed bidding strategies in the DAM under the 1R option results in infeasible day-ahead hybrid resource schedules in real time, which leads to increased reliance on more expensive quick-start generation resources (such as GTs and ICs) that must be used to replace the generation that is not available from the hybrid facilities in the RTM to ensure power balance.

In the 1R option, the NoGC scenario tends to outperform the UnGC scenario. The ability to charge from the grid in the UnGC option leads to more frequent dispatches of the hybrid facilities at their maximum charge and discharge capacities in the DAM. This is due to the developed bidding strategies that ultimately yield infeasible day-ahead schedules in real-time operations. In contrast, the NoGC option relies on the co-located VER component for charging, resulting in less aggressive offers and fewer instances of infeasible day-ahead schedules in real-time operations. Consequently, the UnGC option requires a greater reliance on expensive quick-start generation to compensate for the infeasible generation from the hybrid facilities in real-time operations.

Alternatively, for the 2R option, the UnGC scenario seems to perform better than the NoGC scenario. The ability of the hybrid facility to charge from the grid results in more efficient scheduling of the system's resources, e.g., hybrid facilities charge when the costs are the lowest. This requires more load to be served than in a case with NoGC, but then it also potentially provides that additional stored energy during the peak hours (which a case with NoGC does not), consequently resulting in greater cost savings when compared to the NoGC option for the 2R model.

In some scenarios, for both 2R and 1R participation options, the simulations indicate that it might not always be advantageous for hybrid storage facilities to align their entire day-ahead schedule for every hour. This is particularly true when there is a possibility of imbalance arising from errors in VER forecasts, since balancing the hybrid schedule for the present time period can hinder its ability to fulfill its day-ahead schedule later in the day, which could prove to be more advantageous for the system. This results in greater production costs when compared to the base-case scenario for both options. However, even in this case, the greater increases in real-time production costs are observed under the 1R option due to increased reliance on more expensive quick-start generation resources.

System reliability. For the test system under consideration, and for the case scenarios analyzed in this study, no instances of power imbalances (such as load-shedding or over-generation), reserve shortages, violations of the storage SoC constraints, or hybrid facility interconnection constraints are observed in the real-time scheduling cycle under either of the hybrid resource participation options at their stipulated levels. However, it is important to note that this outcome may not be applicable to alternative test systems featuring dissimilar resource mixes, such as a scenario characterized by restricted quick-start or ramping capabilities, limited transmission capacity, or more significant integration of hybrid and renewable energy resources that may yield different reliability conclusions.

Asset profits and incentives. Granular models such as the 2R participation options provide greater short-run profits. This is primarily due to fewer buyback purchases in the RTM when compared to the 1R option (that had infeasible day-ahead schedules cleared in the DAM based on the offers/bids being too aggressive), or greater revenues from the DAM when compared to the 1R option, due to the economics of the developed bidding strategies based on the simulation period under consideration. In general, the 1R option has an increased likelihood of not being able to provide what was cleared in the DAM in real time. This is due to the aggressive hybrid resource bidding strategies and the absence of explicit SoC consideration in the market clearing software when determining the cleared day-ahead hybrid resource schedules to begin with. This limitation results in discrepancies and SoC infeasibilities that are further aggravated by hybrid resource forecast errors and cannot be used as-is in real time; hence the energy buybacks in real time to respect physical limitations. Alternatively, in some simulation periods, the 1R option might result in lower revenues from the DAM since the cleared day-ahead hybrid resource schedules are lower due to the economics of the developed bidding strategies when compared to the 2R cases that explicitly consider SoC.

For this test case, for periods with low load conditions such as in April, there are more significant differences in two-settlement profits from using the 2R participation option in the near-term with the current resource mix when compared to the future resource mix with a higher penetration of renewables and hybrids. This can generally be attributed to the depressed energy prices (with marginal cost pricing) in future systems with deeper penetrations of zero marginal cost resources. However, for periods with peak load conditions, such as July, there are more significant differences in two-settlement profits from using the 2R participation option in the future resource mix with higher penetration levels of VER and hybrids, when compared to the current resource mix with relatively lower penetration of renewables and hybrids. Irrespective of the VER penetration, given the peak load conditions in July, there is the potential for a greater need to have more traditional resources online to meet system peak demand needs. This typically results in higher energy prices than low load conditions and consecutively impacts revenue and short-run profit results. This result really depends on the system resource mix and how the hybrid resources are utilized under different system conditions. For this test case, for the low VER, low hybrid penetration scenario, although economical, hybrids are not utilized as much for the peak load conditions in July. This is because there is a need to have other more traditional resources (i.e., with commitment constraints) online and potentially producing at minimum generation (or otherwise) to either meet the peak demand needs or the ramping needs in future intervals in the horizon.

Hybrid resource capability to follow different real-time operational strategies. The 1R participation option generally observes a greater number of occurrences, where the hybrid storage resources are unable to adhere to the different real-time operational strategies since there is a greater likelihood for SoC violations under this option with the developed bidding strategies.

For both April and July simulation periods, and for both low and high VER penetration scenarios, the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option appear to consistently perform significantly better than the *1R Self-Managed Hybrid Participation* option under the SF real-time operational strategy. In the SF real-time operational strategy, the 2R participation options have fewer number of intervals that are limited by insufficient SoC or maximum SoC when compared to the 1R participation option due to the granular representation of SoC in the DAM. In the case of the 2R options, forecast error of the renewable component may result in deviations from the day-ahead storage schedule in one real-time interval despite the SF strategy in order to be able to respect the hybrid inverter limit. That then impacts its ability to adhere to the SF real-time operational strategy in subsequent intervals due to the temporal coupling of the stored energy.

For the low VER penetration scenario, for both the April and July simulation periods, under the SF real-time operational strategy, the *2R ISO-Managed Co-located Participation* option seems to perform better than the *2R ISO-Managed Linked Co-Located Participation* option with a lower count of intervals limited by insufficient SoC. Now, since the storage component in the NoGC cases charges solely from the VER component, forecast error from the VER component results in deviations in the stored energy levels of the storage component. The mismatch of stored energy levels in day-ahead and real-time scheduling stages contributes to the higher number of intervals limited by insufficient SoC. On the contrary, the *1R Self-Managed Hybrid Participation* option exhibits an opposite trend, with a higher count of intervals limited by insufficient SoC for the UnGC option compared to the NoGC option for the low VER penetration scenario, for both April and July simulation periods, under the SF real-time operational strategy. In the 1R option, when the storage component has the flexibility to charge from the grid, it often schedules relatively more aggressively in the DAM with a greater number of intervals cleared at maximum charging or maximum discharging dispatch limits when compared to the NoGC option. This results in excessive replenishment or depletion of the stored energy in the storage component at the day-ahead stage that becomes infeasible to follow in the real-time stage due to the SoC restrictions being respected in real time. Alternatively, when the storage component does not have the flexibility to charge from the grid, it is not dispatched at maximum charge or maximum discharge dispatch limits as often. This is because of its complete dependence on the renewable generation, which results in a reduced number of intervals that are limited by insufficient SoC.

In the HB real-time operational strategy, despite the consideration of the SoC in the DAM under the 2R participation options, there can still be a greater number of intervals that are limited by insufficient SoC or maxed out SoC capacity when compared to SF real-time operational strategy. This is true because HB aims to balance out the current issues such as forecast deviations from the renewable component, which is likely to lead to SoC issues later on for the ESR component of the facility. Furthermore, in the HB real-time operational strategy, there are occurrences where the intervals are limited by both insufficient charge capacity and max SoC simultaneously. However, as mentioned in the Results section, the included results avoid such instances of double counting by only including such occurrences either in the count of the intervals limited by insufficient charge capacity or in the count of the intervals limited by maxed out SoC, but not both. Finally, when comparing the cumulative count of intervals limited by insufficient discharge capacity, insufficient charge capacity, insufficient SoC capacity, and maximum SoC, it appears that the *2R ISO-Managed Co-located Participation* option and the *2R ISO-Managed Linked Co-Located Participation* option generally performs better than the *1R Self-Managed Hybrid Participation* option under the HB real-time operational plan for both April and July simulation periods for both low and high VER penetration scenarios. However, if individual metrics are compared against each other across the different participation options, it is hard to predict which participation option may perform better under the HB real-time operational plan owing to its design and the temporal nature of the SoC constraint, where an action in one real-time interval can ripple through time and impact subsequent real-time intervals.

Although real-time bidding is expected to become more advanced in practical implementation, the simulations indicate that it might not always be advantageous for hybrid storage facilities to align their entire day-ahead schedule for every hour, particularly when there is a possibility of imbalance arising from errors in VER forecasts. Balancing the hybrid schedule for the present time period could hinder its ability to fulfill its day-ahead schedule later in the day, which could prove to be more advantageous for the system.

Load payments. For this test system, given the absence of any power imbalances or reserve shortages that may impact the volatility of market clearing prices in real-time operations, a majority of the differences in the two-settlement load payments stem from the component that has to do with the day-ahead load payment. Since the day-ahead system load is much larger than the real-time deviations from day-ahead load, any small difference in DAM clearing prices between the different case scenarios can bring about major differences between the day-ahead load payments, which then impacts the two-settlement load payments more significantly than real-time load payments. Consequently, this study deems it crucial to better understand the impact of the different participation options on price formation in future work. The implications on the load payments are decidedly dependent on the cleared energy awards for the hybrid storage facilities that can differ based on the submitted bidding strategies or the explicit SoC consideration under the alternate participation options, since the cleared awards then impact the market clearing prices and the calculated load payments.

For the low-load April simulation period, the two-settlement load payment for the NYISO FP is consistently greater for the *2R ISO-Managed Co-located Participation* option (2R, UnGC) when compared to the *1R Self-Managed Hybrid Participation* option (1R, UnGC) under both SF and HB real-time operational strategies for both low and high VER penetration levels. For April, the cleared day-ahead hybrid resource schedules are generally higher for the 1R cases with the developed bidding strategies when compared to the 2R cases that explicitly consider SoC. This results in flatter day-ahead load prices for the 1R cases due to the energy shifting nature of the storage component. Consequently, the day-ahead load payments are consistently lower for the 1R cases, which reduces the two-settlement load payments significantly. The opposite is true for the real-time hybrid resource schedules and load prices for the 1R cases, since the hybrid facilities must buy back much of the energy that they cannot provide in real time due to SoC restrictions. On the contrary, for the peak load July simulation period, the two-settlement load payment for the NYISO FP is generally lower for the *2R ISO-Managed Co-located Participation* option (2R, UnGC) when compared to the *1R Self-Managed Hybrid Participation* option (1R, UnGC) under both SF and HB real-time operational strategies for both low and high VER penetration levels. For July, the cleared day-ahead hybrid resource schedules are generally lower with the developed bidding strategies for the 1R cases when compared to the 2R cases that explicitly consider SoC. As a result of the lower cleared awards for hybrid facilities under the 1R option, the day-ahead load prices are less flat when compared to the 2R option. Consequently, the day-ahead load payments are higher for the 1R cases, which increases the two-settlement load payments.

Computational efficiency. Granular models such as the 2R participation options tend to provide theoretical efficiency gains, but they also add computational complexity to the market clearing software (observed through greater day-ahead solve times) compared to the 1R participation model. This is primarily due to explicit consideration of SoC management that requires explicit modeling of the hour-to-hour chronology for the storage component. The solve times were observed to be greater for the peak-load simulation periods when compared to the low-load simulation periods for both 2R and 1R participation options, given the interaction with other constraints (such as unit commitment constraints) under stressed system conditions. Analogously, the day-ahead solve times for the NoGC cases are mostly greater than the UnGC cases for both 2R and 1R participation options. In general, it can be inferred from the simulation results that although the 2R participation options may be potentially advantageous for both the asset owner and the ISO/RTO, they may be too computationally intensive to enable, especially when larger amounts of these emerging resources integrate into the grid.

5.1 Recommendations for Further Examination

Participation in the real-time energy market. This study phase primarily focused on evaluating the key differences that alternative market designs for hybrid storage resources have on key metrics through modeling, simulation, and analysis, while focusing impacts on the DA and RT energy markets. However, the developed bidding strategies under the 1R option were considered only in the day-ahead energy market. Offers/bids were not used in the RTM, but instead real-time operation was represented by using two different operational strategies of the hybrid resource's day-ahead schedule (i.e., SF and HB). This allowed the study team to have more confidence in the study on day-ahead participation of hybrid storage resources. Future work should investigate real-time re-optimization of hybrid storage resources using updated offers/bids in real time under the 1R option rather than the realistic operational strategies considered in this phase of the study. This will also allow for better accommodating the impacts from forecast deviations for instance. However, it is worth emphasizing that updating bids in real time, or utilizing real-time reoptimized SoC management, is very complex.

Other scenarios and valuation sensitivities. It would be valuable to assess how variations of the technology could impact the simulation results of this study. These variations encompass several factors, such as:

- Composition of the hybrid facility, including thermal hybrid storage resources, nuclear hybrid storage resources, hydropower hybrid storage resources, etc. Other sensitivities include different hybrid sizing, varying storage-to-generation capacity ratio, point of interconnection capacity, hybrid location, and storage duration.
- Fluctuations in natural gas prices.
- Examination of the effects of electrification on load.
- Analysis of interchange impacts with neighboring regions that are also undergoing significant changes in their resource mix.
- Consideration of network factors, such as intra-zonal congestion.
- Evaluation of changes in capacity build-out and retirements.

- Exploration of other scenarios and sensitivity analyses for valuation purposes.

Studying these factors will provide a comprehensive understanding of how different technological variations can influence the outcomes and implications discussed in the simulation results.

Additional enhancements to the proposed participation options. Further examination of additional enhancements to the proposed participation models for hybrid storage resources is also important. This includes aspects that have to do with potential representation of battery storage degradation costs under the alternate participation options. Moreover, it is expected that the participation of storage-based resources in electricity markets will dramatically increase soon but may not be able to scale with ideal market modeling under the proposed 2R participation options due to computational limitations. Future work also should investigate the computational efficiency implications of replacing the explicit modeling of hour-to-hour chronology under the proposed 2R participation options with an implicit modeling of chronology through fewer wrapper constraints for storage. This will allow for massive integration of storage-based resources without adverse computational or reliability and economic impacts.

Participation in the ancillary services market. The quantitative analysis conducted in this phase of the study included the modeling of ancillary services markets, but the simulation runs did not consider the eligibility of hybrid storage resources to provide such services. It is worth mentioning that this decision was made for modeling purposes only, and not reflective of the actual technical capabilities of these resources. In fact, hybrid resources are capable of providing these services. Moreover, advanced participation models can further enable hybrid facilities to potentially provide such essential reliability services across their charging and discharging dispatch ranges, which will enhance the value stacking opportunities for these emerging technologies. Future work should also investigate the impact of the proposed participation models with hybrid storage resource participation in ancillary services markets.

Participation in the capacity market or resource adequacy. Another impact not covered in this study that is useful to understand is the capacity value of hybrid storage resources with different participation models. The rules for accrediting the capacity of storage and hybrid resources are intricate since they encompass not only forced outage rates but also factors such as interconnection limits and unavailability arising from the uncertainty of wind/solar energy and from the insufficient state of charge. The accreditation process for storage varies across regions, with some utilizing a straightforward approach based on the storage duration, while others rely on the effective load carrying capability (ELCC) metric.

Other considerations. Other future considerations that are more difficult to quantify include impacts on the ease of doing business, energy management system applications (e.g., real-time contingency analysis, state estimation, automatic generation control), and the interconnection process, if any. However, these are still crucial to consider when evaluating the overall benefits of developing and integrating new participation models into wholesale electricity markets. Participation model options can also have different implications for price formation, price setting, market settlements, make-whole payments, and market mitigation procedures that are harder to quantify but are also important to consider in the future. Equally important is understanding the costs of implementing such participation models and determining whether the anticipated benefits outweigh the costs of implementation.

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