State of Charge Management Concepts and Options for Stand-alone Electric Storage Resources

FERC Technical Conference

Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience through Improved Software

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Outline

- FERC Order 841
- State-of-Charge Management (SOCM): Introduction
- SOCM in Day-ahead Markets (DAM): Implications of market clearing software
- SOCM Options: Other market characteristics (or implications)

FERC Order 841[1]: Summary

- ISOs must include a **participation model** for electric storage resources (ESRs) that allows them to participate in energy, ancillary service, and capacity markets when technically capable of doing so
- ESRs must be eligible to **set the wholesale price** as both a buyer and seller when the marginal resource
- ISOs must **account for physical parameters** of ESRs through bidding or otherwise
- ISOs must allow a minimum size requirement that is at most **100 kW**
- Sale of energy that is stored from purchases in the wholesale market must be **sold at wholesale nodal prices**
- ISOs must allow **self-management** of state of charge (SOC)

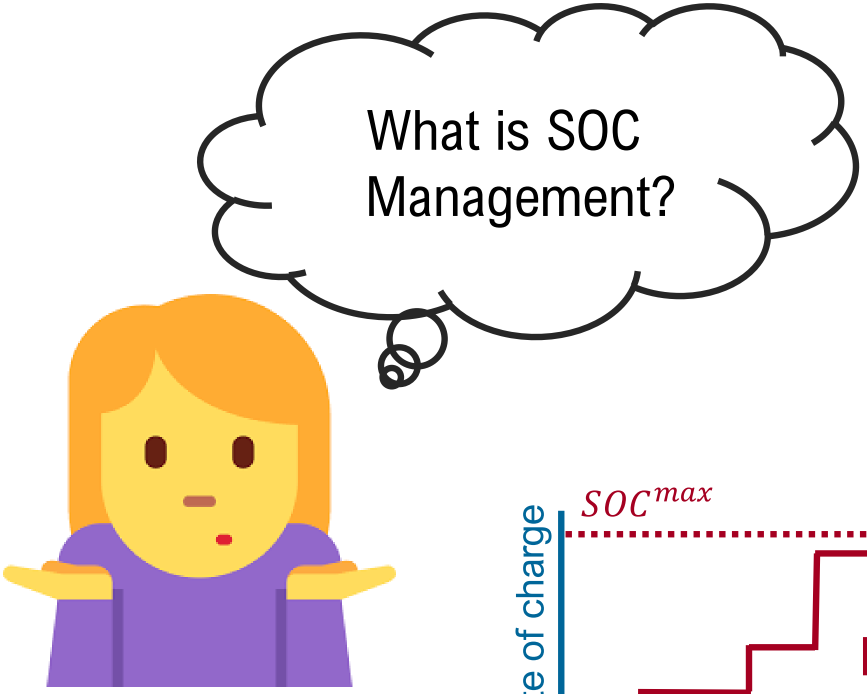
[1] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC Order 841, Final Rule, 162 FERC 61, 127 (February 15, 2018) ("Order No. 841").

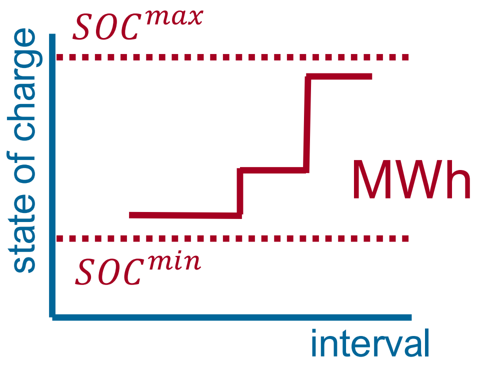
State of Charge Management

[2] *Electricity Market Design Implications for Bulk Energy Storage*. EPRI, Palo Alto, CA: 2019. 3002013865.
[3] *Integrating Electric Storage Resources into Electricity Market Operations: Evaluation of State of Charge Management Options.* EPRI, Palo Alto, CA: 2019. 3002013868.
[4] *Electricity Market Integration of Energy Storage and Hybrid Storage-Plus-Renewables Technologies: 2019 Update.* EPRI, Palo Alto, CA: 2020. 3002016759.
[5] *Integrating Electric Storage Resources into Electricity Market Operations: Evaluation of Day-ahead and Real-time State of Charge Management Options*. EPRI, Palo Alto, CA: 2020. 3002016228.
[6] N. G. Singhal and E. G. Ela, "Incorporating electric storage resources into wholesale electricity markets while considering state of charge management options," in *Proc. CIGRE USNC Grid of the Future Symp.*, https://cigre-usnc.org/2019-grid-of-the-future-papers/, 2019.
[7] N. G. Singhal and E. G. Ela, "Pricing impacts of state of charge management options for electric storage resources," in *Proc. IEEE Power and Energy Soc. Gen. Meeting*, accepted for publication, Aug. 2020.

State of Charge Management: Introduction

- No *definitive* statement within FERC Order 841 on what SOC-Management means resulting in different interpretations and requests for clarifications (does not require ISO-SOC-Management; requires provision of SOC related bid parameters by ESRs and for ISOs to "*consider them*")





State of Charge Management: Options

Self-Schedule

- ESR self-dispatches its output and is insensitive to price.

Allowed by all ISOs/RTOs

Self-SOC-Management

- ESR provides an offer curve analogous to traditional resources.
- ESRs can set offers to ensure desired and feasible SOC.
- ISO schedules without SOC consideration

CAISO, NYISO, ~~PJM ESRs~~

SOC-Management-Lite

- ESR provides offer curve.
- ISO does <u>not</u> schedule ESR if it would lead to infeasible SOC.
- Schedules are <u>not</u> optimized across time to optimize ESR schedules.

SPP, ISO-NE, MISO, PJM ESRs

ISO-SOC-Management

- ESR may or may not provide offer curve.
- ISO ensures SOC feasibility and optimizes ESR schedules across time to minimize cost.

CAISO, NYISO, PJM PSH units

→ ISO Scheduling Responsibility / Theoretical Economic Efficiency and Reliability Benefits / Complexity

← ESR Asset Owner Participation Responsibility and Flexibility / Computational Efficiency

Key ESR Design Topic

Order 841 Aspect	NYISO	PJM	SPP	ISO-NE	MISO	CAISO
State of Charge Management	1. Only a few ISOs are offering both **ISO-SOCM** and **Self-SOCM**. Other ISOs are offering a hybrid **SOCM-Lite** option. 2. **ISO-SOCM**: SOC is a variable in multi-interval optimization; ISO ensures SOC feasibility. 3. **SOCM-Lite**: SOC is a parameter in sequential optimization; ISO ensures SOC feasibility.					
	ISO-SOCM (excludes desired ending SOC level) and **Self-SOCM** (does not ensure SOC feasibility, but ISO will align schedules with telemetered SOC in RTM); ESRs can switch between SOCM modes within RTM, and between DAM and RTM; **PSH plants – Self-SOCM**	**ESRs – Self-SOCM** (current SOC telemetry will not be used to optimize ESRs across intervals; directed by FERC to instead implement **SOCM-Lite**, i.e., ensure SOC feasibility and account for: 1) SOC, and 2) min and max SOC limits in its sequential optimization); **PSH plants – ISO-SOCM**	**SOCM-Lite** (ensures SOC feasibility in sequential optimization); can submit max daily MWh limit	**SOCM-Lite** (includes two new telemetered points in RT, i.e., 15-minute and 1-hour available energy and storage, to ensure SOC feasibility in sequential optimization); ESFs can submit max daily MWh charge and discharge limits in the DAM	**SOCM-Lite** (ensures SOC feasibility in sequential optimization); max daily MWh limit included only for PSH plants	**ISO-SOCM** (excludes desired ending SOC level) and **Self-SOCM** (does not ensure SOC feasibility); can submit daily min and max MWh limits for DAM

- Key questions:
  - Why do the ISOs/RTOs differ in the SOCM option that is being offered to ESRs?
  - How does the market clearing software design impact SOCM?

DAM: Day-ahead Market; **ESFs**: Electric Storage Facilities; **ESR**: Electric Storage Resource; **PSH**: Pumped Storage Hydro; **RTM**: Real-time Market; **SOC**: State of Charge; **SOCM**: SOC Management

State of Charge Management Options: DAM ESR Offer Implications Illustrative Examples

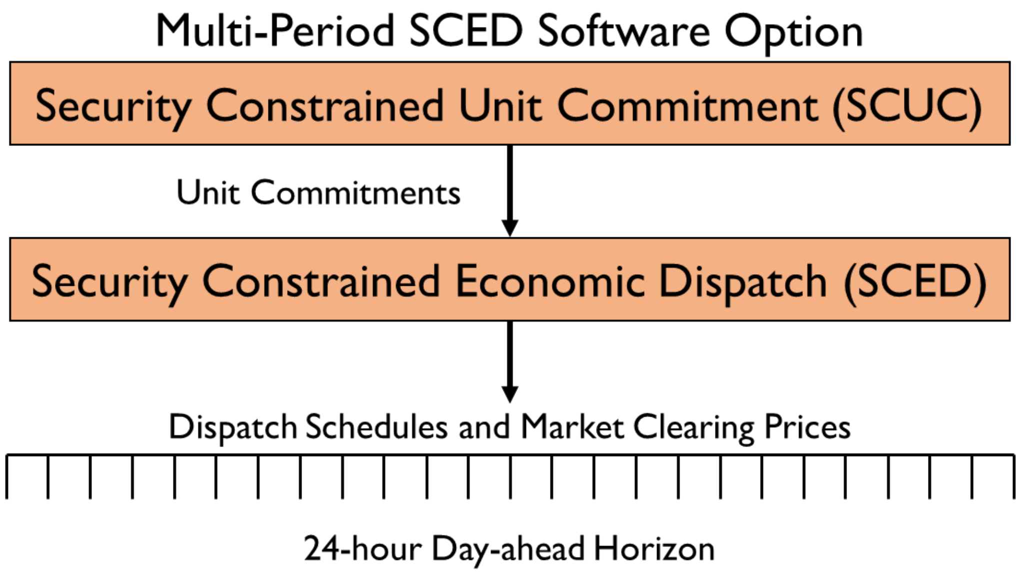
[4] *Electricity Market Integration of Energy Storage and Hybrid Storage-Plus-Renewables Technologies: 2019 Update.* EPRI, Palo Alto, CA: 2020. 3002016759.
[5] *Integrating Electric Storage Resources into Electricity Market Operations: Evaluation of Day-ahead and Real-time State of Charge Management Options*. EPRI, Palo Alto, CA: 2020. 3002016228.

Market Clearing Software Implications

- EPRI research has shown that the SOCM structure for the DAM is partially determined through software subtleties
- Different wholesale electricity markets have different software characteristics for market clearing in the day-ahead
- This can predominantly impact whether the ISO is using ISO-SOC-Management or SOC-Management-Lite

Market Clearing Software Subtleties

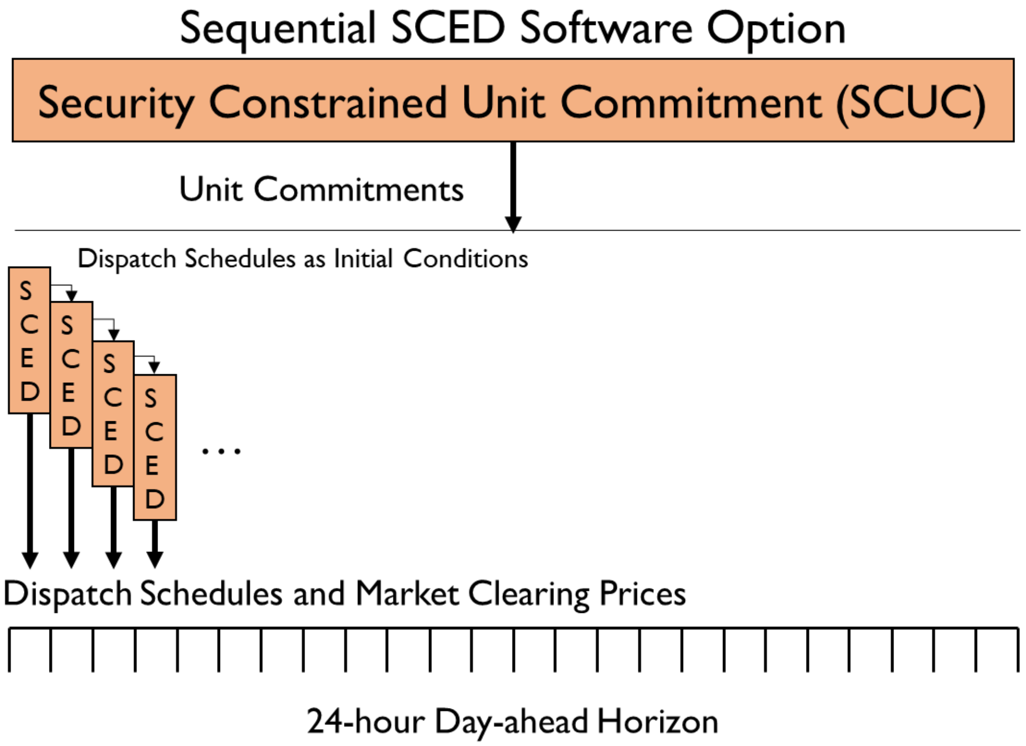
ISO-SOC-Management



CAISO, NYISO

Previous hour's SOC is a variable in dispatch/LMP calculation

SOC-Management-Lite



SPP, ISO-NE, MISO, PJM*

Previous hour's SOC is a parameter in dispatch/LMP calculation

*PJM uses a separate software program, referred to as pumped hydro optimizer, for determining pumped storage hydro (PSH) schedules

State of Charge Management: Options

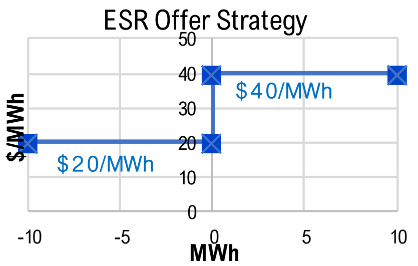
ISO-SOC-Management

1. Multi-interval economic dispatch
2. Previous hour's SOC is a variable in economic dispatch/ LMP calculation
3. SOC is managed across a known horizon to ensure feasibility and optimality
4. Does not require offers, but ESRs can still submit offers, e.g., to account for degradation costs
5. May include an additional feature to avoid myopic decisions, e.g., a desired SOC at the end of the horizon, or a value in $/MWh provided by the ESR to demonstrate the value of keeping energy left over at the end of the day

SOC-Management-Lite

1. Sequential economic dispatch
2. Previous hour's SOC is a parameter in economic dispatch/ LMP calculation
3. SOC is used in each market interval to ensure the ESR's schedule is feasible
4. Requires offers to be submitted by market participants

Illustrative Example: No ESR



Gen A, Gen B and ESR have operating characteristics below:

Generator A

Generating range: 0 to 60 MW

Marginal cost: **$25/MWh**

Generator B

Generating range: 0 to 60 MW

Marginal cost: **$100/MWh**

Electric Storage Resource

Operating range: – 10 MW to 10 MW

Energy capacity: 10 MWh

Round-trip efficiency: 100%

Segmented offers: **$20/MWh charge**

$40/MWh discharge

Case 1: Schedule results with no ESR

Interval	Demand	Gen A Schedule	Gen B Schedule	Price	Cost
Interval 1	50 MWh	50 MWh	0 MWh	$25/MWh	(50 MWh)*($25/MWh) = $1250
Interval 2	100 MWh	60 MWh	40 MWh	$100/MWh	(60 MWh)*($25/MWh) + (40 MWh)*($100/MWh) = $5500

Demand increase in Interval 2 requires energy to be provided by the more expensive Gen B, resulting in higher marginal price and higher generation cost in Interval 2

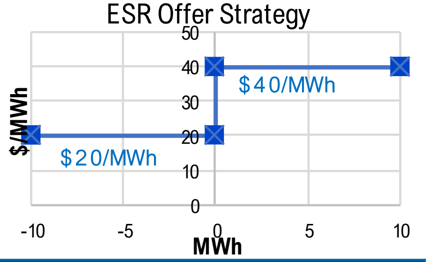
Illustrative Example: With ESR, Sequential Optimization

Gen A, Gen B and ESR have operating characteristics below:

Generator A
Generating range: 0 to 60 MW
Marginal cost: **$25/MWh**

Generator B
Generating range: 0 to 60 MW
Marginal cost: **$100/MWh**

Electric Storage Resource
Operating range: – 10 MW to 10 MW
Energy capacity: 10 MWh
Round-trip efficiency: 100%
Segmented offers: **$20/MWh charge**
$40/MWh discharge



Case 2: Schedule with ESR, starting SOC at **100%, sequential** optimization

Given that the ESR has a starting SOC of 100% and offers to discharge at $40/MWh, which is $60/MWh cheaper than Gen B, the market clearing software reduces the energy needed from Gen B for Interval 2 and saves the system $60/MWh.

Interval	Demand	Gen A Schedule	Gen B Schedule	ESR Schedule	Cost
Interval 1	50 MWh	50 MWh	0 MWh	0 MWh	(50 MWh)*($25/MWh) = $1250
Interval 2	100 MWh	60 MWh	30 MWh	10 MWh	(60 MWh)*($25/MWh) + (30 MWh)*($100/MWh) + (10 MWh)*($40/MWh) = $4900

SOCM-Lite: Incorporates SOC feasibility constraints

ESR participation reduces generation cost in Interval 2 compared to Case 1

Illustrative Example: Market Clearing Software Options

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 3: Schedule with ESR, starting SOC at **0%**, **sequential** optimization

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	50	0	0	$1250
Interval 2	100	60	40	0	$5500

Costs similar to Case 1 without ESR

SOCM-Lite: Incorporates SOC feasibility constraints; ESR cannot be used in Interval 2 as it has no energy to provide

Given that the ESR has a starting SOC of 0% (empty), it has no energy to provide in Interval 2, resulting in generation costs that are similar to the case with no ESR participation (Case 1).

*Note: Exclusion of SOC feasibility constraints can result in ESR discharging in Interval 2, potentially selling energy it cannot produce (**Self-SOCM**)*

Illustrative Example: Market Clearing Software Options

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 3: Schedule with ESR, starting SOC at 0%, **sequential** optimization

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	50	0	0	$1250
Interval 2	100	60	40	0	$5500

Costs similar to Case 1 without ESR

SOCM-Lite: Incorporates SOC feasibility constraints; ESR cannot be used in Interval 2 as it has no energy to provide

Case 4: Schedule with ESR, starting SOC at 0%, **simultaneous** multi-interval optimization

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	60	0	-10	$1300
Interval 2	100	60	30	10	$4900

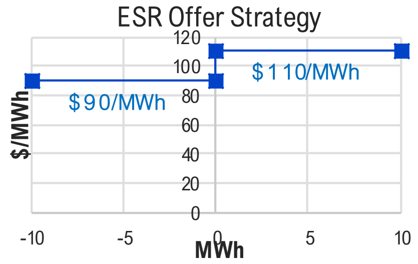
Reduced generation cost in comparison to Case 1 without ESR

ESR is scheduled to charge in Interval 1 in spite of the marginal price ($25/MWh) being higher that its bid to charge ($20/MWh) so that it has energy to discharge in the high priced ($100/MWh) Interval 2, thereby, reducing the costs associated with Gen B in Interval 2 and increasing the profit for the ESR (by $75/MWh).

ISO-SOCM: ESR operated across intervals to minimize costs across the entire horizon, even if it may look uneconomic in an individual interval, i.e., Interval 1

Note: In spite of the ESR using an offer curve for both Cases 3 and 4, Case 4 represents ISO-SOCM whereas Case 3 represents SOCM-Lite based on the market clearing software option (sequential vs. simultaneous optimization)

Illustrative Example: Impact of ESR Offers



Gen A, Gen B and ESR have operating characteristics below:

Generator A

Generating range: 0 to 60 MW

Marginal cost: **$25/MWh**

Generator B

Generating range: 0 to 60 MW

Marginal cost: **$100/MWh**

Electric Storage Resource

Operating range: – 10 MW to 10 MW

Energy capacity: 10 MWh

Round-trip efficiency: 100%

Segmented offers: **$90/MWh charge**
$110/MWh discharge

Example: ESR wants to make a profit of at least $20/MWh

Case 2B: Schedule with ESR, starting SOC at **100%**, **sequential** optimization

Interval	Demand	Gen A Schedule	Gen B Schedule	ESR Schedule	Cost
Interval 1	50 MWh	50 MWh	0 MWh	0 MWh	(50 MWh)*($25/MWh) = $1250
Interval 2	100 MWh	60 MWh	40 MWh	0 MWh	(60 MWh)*($25/MWh) + (40 MWh)*($100/MWh) = $5500

SOCM-Lite: Incorporates SOC feasibility constraints

The ESR does not operate at all since it is already charged to its energy capacity to further charge in Interval 1 (in spite of the low marginal price of $25/MWh) and is too expensive to discharge in Interval 2 (marginal price of $100/MWh is lower than its offer to sell, i.e., $110/MWh)

Market Software Options: Impact of ESR Offers

Case 3B: Schedule with ESR, starting SOC at 0%, **sequential** optimization ($90/$110 ESR Offer)

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	60	0	-10	$600
Interval 2	100	60	40	0	$5500

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$90/MWh charge $110/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

SOCM-Lite: Incorporates SOC feasibility constraints; ESR charges due to low price of Interval 1, but does not clear to discharge in Interval 2 given its offer to sell is not competitive

The ESR charges in Interval 1 since its bid to charge (or buy) is higher than the marginal price in Interval 1; however, the energy charged remains stored in the ESR since its offer to discharge (or sell) is not competitive with Gen B (marginal unit) in Interval 2.

Market Software Options: Impact of ESR Offers

Case 3B: Schedule with ESR, starting SOC at 0%, sequential optimization ($90/$110 ESR Offer)

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	60	0	-10	$600
Interval 2	100	60	40	0	$5500

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$90/MWh charge $110/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

SOCM-Lite: Incorporates SOC feasibility constraints; ESR charges due to low price of Interval 1, but does not clear to discharge in Interval 2 given its offer to sell is not competitive

The ESR charges in Interval 1 since its bid to charge (or buy) is higher than the marginal price in Interval 1; however, the energy charged remains stored in the ESR since its offer to discharge (or sell) is not competitive with Gen B (marginal unit) in Interval 2.

Case 4B: Schedule with ESR, starting SOC at 0%, simultaneous optimization ($90/$110 ESR Offer)

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	60	0	-10	$600
Interval 2	100	60	40	0	$5500

Case 4B mirrors 3B in spite of both the intervals being evaluated together in 4B

ISO-SOCM: ESR operated across intervals to minimize costs across the entire horizon

Challenge*: No value placed on stored energy beyond the two intervals; if a low price were to happen next, i.e., Interval 3, the ESR could not take advantage of buying energy to sell once again to make up its spread.*

Day-ahead SOCM: Offer Implications

- Given the challenge with Case 4B, EPRI research further emphasizes on the benefits of the ISO-SOCM option incorporating a value or constraint to define energy stored at the end of the optimization horizon in addition to the simultaneous multi-interval optimization.
- The ESR can then potentially take advantage of multiple charge/discharge cycles to make up its spread.
- For instance, the ISO can ensure that the SOC at the end of the optimization horizon is equal to the SOC at the beginning of the optimization horizon (e.g., for a day-ahead 24-hour optimization horizon). This assists the ISO in avoiding myopic decisions that may empty out the ESR.
- Case 4C is similar to Case 4B, but with an additional constraint that requires the end of the optimization horizon SOC to equal the beginning SOC, i.e., 0%. Note that, although not ideal, Case 4C considers a two-interval optimization horizon for the day-ahead market for simplicity and illustration purposes.

ISO-SOCM: Importance of End of Horizon Value/Constraint

Case 4C: Schedule with ESR, starting and ending SOC at 0%, simultaneous optimization ($90/$110 ESR Offer)

Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)
Interval 1	50	60	0	-10	$600
Interval 2	100	60	30	10	$5600

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$90/MWh charge $110/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 4C results in identical schedules to Case 4

ISO-SOCM: ESR operated across intervals to minimize costs across the entire horizon

***Note**: End of horizon constraint emphasizes the <u>spread</u> between the charge and discharge bids as compared to the individual bid values.*

The solution involves charging the ESR in Interval 1 and discharging the ESR in Interval 2 since doing the same results in a less costly solution when compared to no ESR participation (Case 2B).

Day-ahead SOC Management: Offer Implications

- The next set of examples are provided to better understand the importance of the software solution, i.e., sequential vs. simultaneous, and the SOCM option.
- The examples in the next few slides assume the same physical characteristics for Gen A, Gen B, and the same physical and offer characteristics for the ESR as Cases 1 and 4; however, the marginal cost for Gen B now reduces from $100/MWh to $44/MWh.
- Case 1D represents the case without ESR participation, and Case 4D represents the case with ESR participation and multi-interval simultaneous optimization that includes an end-of-horizon constraint.

Importance of SOCM Options and Software Solution

	Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)	Total Costs ($)
Case 1 (no ESR)	**Interval 1**	50 MWh	50 MWh	0 MWh	No ESR	$1250	$6750
	Interval 2	100 MWh	60 MWh	40 MWh	No ESR	$5500	
Case 4 (ESR, **starting SOC at 0%**, simultaneous optimization)	**Interval 1**	50 MWh	60 MWh	0 MWh	-10 MWh	$1300	$6200
	Interval 2	100 MWh	60 MWh	30 MWh	10 MWh	$4900	
Case 1D (no ESR)	**Interval 1**	50 MWh	50 MWh	0 MWh	No ESR	$1250	$4510
	Interval 2	100 MWh	60 MWh	40 MWh	No ESR	$3260	
Case 4D (ESR, **starting and ending SOC at 0%**, simultaneous optimization)	**Interval 1**	50 MWh	50 MWh	0 MWh	-0 MWh	$1250	**$4510**
	Interval 2	100 MWh	60 MWh	40 MWh	0 MWh	$3260	

Case 1 and Case 4:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 1D and Case 4D:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$44/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

The results are now the same across Case 1D and Case 4D. Although discharging the ESR appears to be competitive in comparison to Gen B in Interval 2 (since the ESR has a lower discharge offer of $40/MWh in comparison to $44/MWh for Gen B), the price spread between the two intervals is not sufficient to justify the ESR operation in Case 4D. This costlier alternative to Case 4D (that is sub-optimal) is shown on the next slide for illustration purposes.

Importance of SOCM Options and Software Solution

	Interval	Demand (MWh)	Gen A Schedule (MWh)	Gen B Schedule (MWh)	ESR Schedule (MWh)	Cost ($)	Total Costs ($)
Case 1 (no ESR)	**Interval 1**	50 MWh	50 MWh	0 MWh	No ESR	$1250	$6750
	Interval 2	100 MWh	60 MWh	40 MWh	No ESR	$5500	
Case 4 (ESR, starting SOC at 0%, simultaneous optimization)	**Interval 1**	50 MWh	60 MWh	0 MWh	-10 MWh	$1300	$6200
	Interval 2	100 MWh	60 MWh	30 MWh	10 MWh	$4900	
Case 1D (no ESR)	**Interval 1**	50 MWh	50 MWh	0 MWh	No ESR	$1250	$4510
	Interval 2	100 MWh	60 MWh	40 MWh	No ESR	$3260	
Case 4D (ESR, starting and ending SOC at 0%, simultaneous optimization)	**Interval 1**	50 MWh	50 MWh	0 MWh	-0 MWh	$1250	$4510
	Interval 2	100 MWh	60 MWh	40 MWh	0 MWh	$3260	

Case 1 and Case 4:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 1D and Case 4D:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$44/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case 4D: If the ESR were to charge in Interval 1 and discharge in Interval 2, the total costs over both the intervals would be higher than no ESR operation in 4D.

Alternative for Case 4D:	Demand (MWh)	Gen 1 Schedule (MWh)	Gen 2 Schedule (MWh)	ESR Schedule (MWh)	Cost ($)	Total Cost ($)
Interval 1	50	60	0	-10	$1300	$4520
Interval 2	100	60	30	10	$3220	

Price spread between the intervals is no longer enough to justify ESR operation

Case Summary[1]

Cases 1 – 4:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Cases 2B, 3B, 4B, 4C:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$100/MWh	60 MW
ESR	$90/MWh charge $110/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Cases 1D, 4D:

	Cost	Capacity
G1	$25/MWh	60 MW
G2	$44/MWh	60 MW
ESR	$20/MWh charge $40/MWh discharge	10 MW +/- 10 MWh / 100% efficiency

Case	Description: ESR	Description: SOC	Description: Software	Description: ESR Offer	Interval	Demand (MWh)	Gen 1 Schedule (MWh)	Gen 2 Schedule (MWh)	ESR Schedule (MWh)	Cost ($)	Total Costs ($)	
Case 1	×		Either		Interval 1	50	50	0	No ESR	$1250	$6750	
					Interval 2	100	60	40	No ESR	$5500		
Case 2	√	100%	Sequential SOCM-Lite	$20/MWh charge $40/MWh discharge	Interval 1	50	50	0	0	$1250	$6150	Low costs since ESR starts at 100% SOC
					Interval 2	100	60	30	10	$4900		
Case 3	√	0%	Sequential SOCM-Lite	$20/MWh charge $40/MWh discharge	Interval 1	50	50	0	0	$1250	$6750	Schedules same as Case 1 (no ESRs)
					Interval 2	100	60	40	0	$5500		
Case 4	√	0%	Simultaneous	$20/MWh charge $40/MWh discharge	Interval 1	50	60	0	-10	$1300	$6200	Avoids myopic decisions
					Interval 2	100	60	30	10	$4900		
Case 2B	√	100%	Sequential SOCM-Lite	$90/MWh charge $110/MWh discharge	Interval 1	50	50	0	0	$1250	$6750	Discharge offer not economically competitive
					Interval 2	100	60	40	0	$5500		
Case 3B	√	0%	Sequential SOCM-Lite	$90/MWh charge $110/MWh discharge	Interval 1	50	60	0	-10	$600	$6100	Economically competitive charge bid
					Interval 2	100	60	40	0	$5500		
Case 4B	√	0%	Simultaneous	$90/MWh charge $110/MWh discharge	Interval 1	50	60	0	-10	$600	$6100	Absence of end-of-horizon constraint/ value
					Interval 2	100	60	40	0	$5500		
Case 4C	√	start 0% end 0%	Simultaneous	$90/MWh charge $110/MWh discharge	Interval 1	50	60	0	-10	$600	$6200	Emphasis on price spread
					Interval 2	100	60	30	10	$5600		
Case 1D	×		Either		Interval 1	50	50	0	No ESR	$1250	$4510	
					Interval 2	100	60	40	No ESR	$3260		
Case 4D	√	start 0% end 0%	Simultaneous	$20/MWh charge $40/MWh discharge	Interval 1	50	50	0	0	$1250	$4510	Price spread not enough
					Interval 2	100	60	40	0	$3260		

[1] *Electricity Market Integration of Energy Storage and Hybrid Storage-Plus-Renewables Technologies: 2019 Update.* EPRI, Palo Alto, CA: 2020. 3002016759.

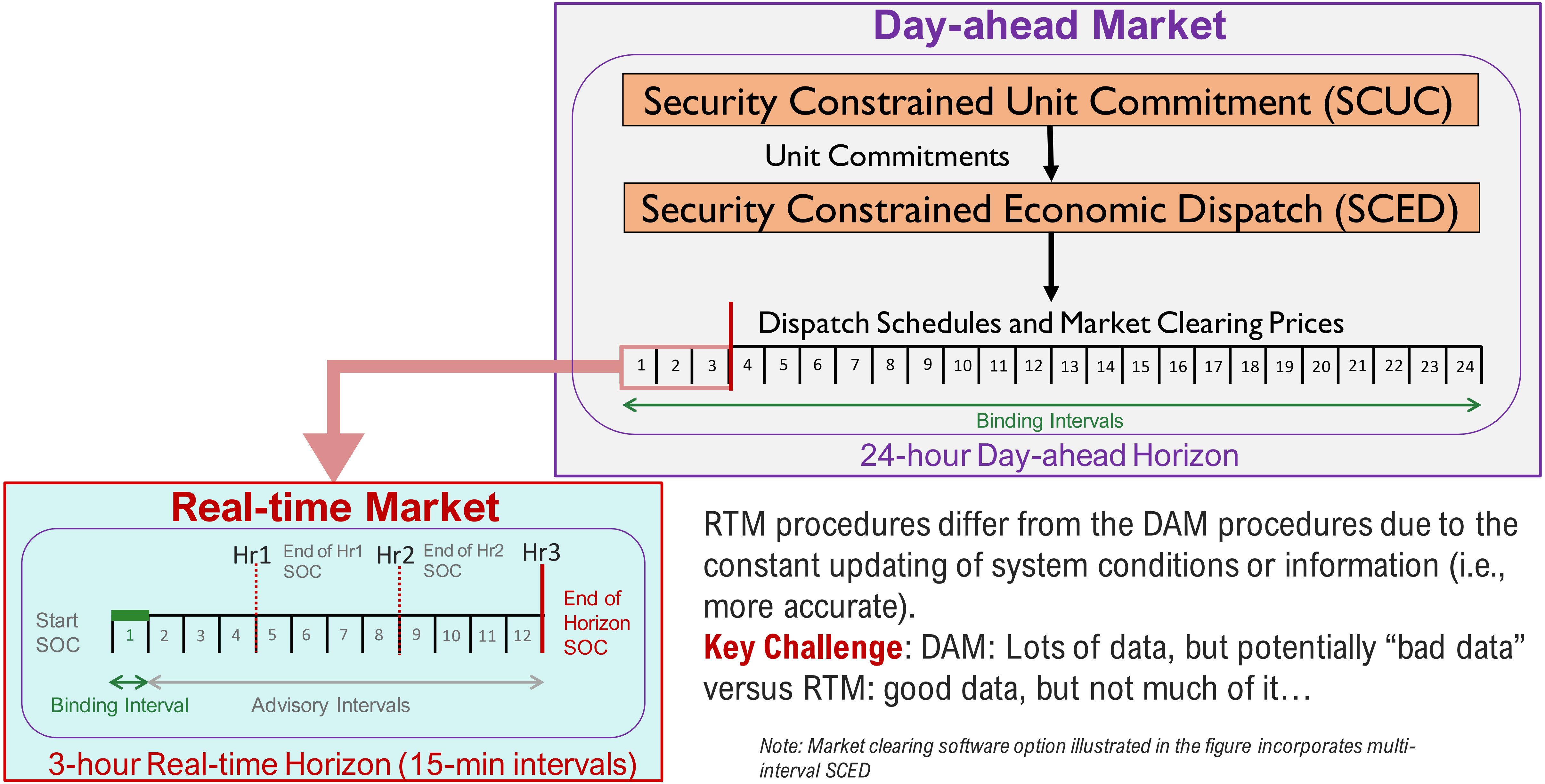
Conclusions: SOCM Implications for the DAM

- Offer strategy of ESRs depends upon the SOCM option and characteristics of the market clearing software used by the ISO
  - Some ISOs solve the DAM across all hours simultaneously while others solve each hour sequentially
- SOCM-Lite, sequential optimization: ESR offers are used on an interval by interval basis by evaluating its competitiveness against the marginal costs of each individual interval
- ISO-SOCM, simultaneous optimization:
  - ESR offers are used as a spread across its charging and discharging values, and are evaluated across all the intervals being considered; i.e., the spread between charging and discharging offers are more important than the individual offer values
  - End-of-horizon constraint or value emphasizes the use of the spread bid
  - May potentially be analogous to the SOCM-Lite option without the end-of-horizon constraint, particularly for short optimization horizons and single cycle ESR operation

SOC Management Options: Market Characteristics[3]

Physical or Operational Characteristic	Self-SOC-Management	SOC-Management-Lite	ISO-SOC-Management
Economic Efficiency (theoretical)	Dependent on ESR offer curves. Infeasible schedules can lead to reliance on more expensive resources.	Dependent on ESR offer curve.	Improved economic efficiency in theory, schedules used to provide overall system-wide least cost based on offers.
SOC Feasibility	Feasibility cannot be guaranteed.	Excepting unforeseen conditions, feasibility can be guaranteed.	Excepting unforeseen conditions, feasibility can be guaranteed.
ESR Asset Owner Responsibility	Provide an offer that maximizes its profit and ensures feasibility. Subject to real-time imbalance payments and/or uninstructed deviation penalties if SOC violated.	Provide an offer that maximizes profit; must have some indication of what prices will potentially be to make most profit. SOC forecast, SOC limits and roundtrip efficiency used by the ISO.	Offer can be used to achieve a minimum profit based on anticipated costs beyond charging. Desired SOC level, SOC forecast and other operating parameters are used by the ISO.
ISO Responsibility	Schedule ESR like a traditional generator but that can be negative injection or positive injection.	Schedule ESR like a traditional generator with two additional SOC feasibility constraints (maximum and minimum SOC) and SOC calculation.	Schedule ESR to meet desired (or optimal) SOC point, aim to provide a price profit/spread, and ensure SOC feasibility constraints.
Optimization in Real-time	Same as day-ahead with offer curve.	Same as day-ahead with offer curve.	Complex. Shorter horizon with updated (more accurate) information. Need to know whether to overwrite day-ahead solution.

The Forecast Dilemma[5][8]



RTM procedures differ from the DAM procedures due to the constant updating of system conditions or information (i.e., more accurate).

Key Challenge: DAM: Lots of data, but potentially "bad data" versus RTM: good data, but not much of it…

Note: Market clearing software option illustrated in the figure incorporates multi-interval SCED

SOC Management Options: Market Characteristics[3]

Physical or Operational Characteristic	Self-SOC-Management	SOC-Management-Lite	ISO-SOC-Management
Price Setting [7]	ESRs can set price equal to offer curve value when marginal.	ESRs can set price equal to a combination of the offer curve value and the shadow price of the SOC constraint when marginal. SOC limit similar to maximum capacity limit in that ESR cannot be marginal if binding SOC constraint.	Complex. ESR can be marginal throughout time period. Price can be based on various dual values (i.e., shadow prices) of several SOC constraints and influence by offers if provided.
Make-Whole Payments	ESR can earn make-whole payments based on offered costs if either revenue less than offer costs when injecting, or greater than bids when withdrawing.	ESR can earn make-whole payments based on offered costs, but not when SOC limits binding.	Complex. ESR can earn make-whole payments if total revenue (payments to minus payments from) is negative. If desired SOC is less than starting SOC, additional modifications to calculation may be warranted.
Market Mitigation and Withholding	Complex. Must distinguish between high prices used to avoid SOC infeasibility with high prices or de-rated range used for withholding.	Fairly straightforward. Higher prices than expected may be mitigated.	If no offers, fairly straightforward. No offers to mitigate. If offer, may need verifiable spread costs.
Computational Efficiency	Fairly straightforward, just additional resources. No additional variables or constraints needed.	Moderate complexity. Requires separate charging and discharging variables, and additional constraints per ESR. Single economic dispatch still limited computation need.	More complexity. All variables and constraints from SOCM-Lite plus additional time-coupling constraints to respect desired SOC limitations.

[7] N. G. Singhal and E. G. Ela, “Pricing impacts of state of charge management options for electric storage resources,” in *Proc. IEEE Power and Energy Soc. Gen. Meeting*, accepted for publication, Aug. 2020.

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