Spring 5-18-2019

# Enabling Electric Storage Participation in Wholesale Markets: An Analysis of FERC Order No. 841

Glenn A. Smith
*University of San Francisco*, gasmith235@gmail.com

This Capstone Project

**Enabling Electric Storage Participation in Wholesale Markets:**
**An Analysis of FERC Order No. 841**

by

**Glenn Smith**

is submitted in partial fulfillment of the requirements
for the degree of:

**Master of Science**
**in**
**Energy Systems Management**

at the

**University of San Francisco**

# Table of Contents

# Abstract

This study has been performed to understand the potential impact that the Federal Energy Regulatory Commission's (FERC) Order No. 841 will have on the adoption of energy storage resources (ESR). This analysis looked at: (1) the Order's requirements, (2) FERC's exercise of its authorized jurisdiction within the Order, and (3) actions taken by the Regional Transmission Organizations (RTO), Independent System Operators (ISO) and FERC to demonstrate compliance with the Order's requirements:

Order No. 841 utilizes a participation model to ensure ESR's are able to participate in wholesale electricity markets to an extent that is reflective of a resource's physical and operation characteristics. The model's effect on market competition will be achieved primarily through a greater realization of merchant value by ESR owners. However, economically optimal levels of ESR capacity and service provision will likely not be achieved through exclusive use of participation models.

Realization of ESR benefits will be heavily dependent on the long-term resilience of the market changes implemented by the Order. FERC's reliance on a conventional exercise of its jurisdiction over interstate wholesale markets can creating unnecessary regulatory uncertainty, or miss opportunities for State-level engagement to maintain the momentum that Order No. 841 provides to ESR participation.

Key aspects of the RTO/ISO's compliance plans were tabulated and analyzed. RTO/ISO's may need to further justify the use of proposed indirect controls to manage ESR physical parameters. Additionally, the widespread use of "dispatch-only" participation models may present participation barriers for some storage technologies.

# List of Figures

# List of Tables

# List of Acronyms and Abbreviations

| Acronym/ Abbreviation | Definition | Acronym/ Abbreviation | Definition |
|---|---|---|---|
| **APPA** | American Public Power Association | **ISO** | Independent System Operator |
| **ATRR** | Alternative Technology Regulation Resource | **ISO-NE** | ISO New England |
| **ATWACC** | After-Tax Weighted-Average Cost of Capital | **LMP** | Locational Marginal Price |
| **BTM** | Behind-the-meter | **MISO** | Midcontinent Independent System Operator |
| **CAISO** | California Independent System Operator | **MSR** | Market Storage Resource |
| **CPUC** | California Public Utilities Commission | **NGR** | Non-Generator Resource |
| **CSF** | Continuous Storage Facility | **NOPR** | Notice of Proposed Rulemaking |
| **DA** | Day Ahead | **NRECA** | National Rural Electric Cooperative Association |
| **DARD** | Dispatchable Asset-Related Demand | **NYISO** | New York Independent System Operator |
| **DER** | Distributed Energy Resources | **OEPI** | Office of Energy Policy and Innovation |
| **EIA** | Energy Information Administration | **PHES** | Pumped Hydroelectric Storage |
| **ERCOT** | Electric Reliability Council | **RMI** | Rocky Mountain Institute |
| **ESR** | Electric Storage Resource | **RT** | Real Time |
| **FCM** | Forward Capacity Market | **RTO** | Regional Transmission Organization |
| **FERC** | Federal Energy Regulatory Commission | **RUC** | Reliability Unit Commitment |
| **FPA** | Federal Power Act | **SPP** | Southwest Power Pool |
| **GA** | Generator Asset | **RTBM** | Real Time Balancing Market |

# Chapter 1 Electricity Storage and Wholesale Electricity Markets

## 1.1 Early Federal Regulatory Considerations

In June, 2010, the Director of the Office of Energy Policy and Innovation (OEPI) opened Docket No. AD10-13-000 to gather comments pertinent to rates, accounting and financial reporting for new electric storage technologies. The OEPI, an office within the Federal Energy Regulatory Commission (FERC), is tasked with coordinating "the development of policies and rules that address emerging challenges" relevant to the electric industry (FERC, 2019a). Aspects of this coordination include provision of policy recommendations derived from energy market analysis, as well as identification of regulatory barriers to greater implementation of innovations in the electric industry. In this docket, OEPI and, by extension, FERC acknowledged the growing technological maturity and commercial operation of newer storage technologies, and sought to understand how to "develop rates and categorize electric storage costs for rate purposes" (FERC, 2010).

Participation of these new storage technologies in electric markets within the scope of FERC's jurisdiction (i.e., interstate wholesale markets), was not viewed as a simple exercise of mimicking the treatment of existing electric system elements (FERC, 2010). For example, pumped hydroelectric storage (PHES), had provided energy storage within the US electric system for approximately 80 years by the time Docket No. AD10-13-000 was opened. For much of this time, PHES resources did not represent a novel component of the grid or require innovative compensation methods for provision of services. In fact, this class of storage resources was primarily developed to occupy the traditional role of a transmission-level interconnected energy generation asset. As illustrated in Figure 1-1, most of the current US PHES capacity was commissioned in the 1960's and 1970's in order to provide peak energy in place of fossil fuel generation as a response to energy shortages that occurred starting in the 1960's (Barbour, Wilson, Radcliffe, Ding, & Li, 2016; Uria-Martinez, Johnson, & O'Connor, 2018; Yang & Jackson, 2011).

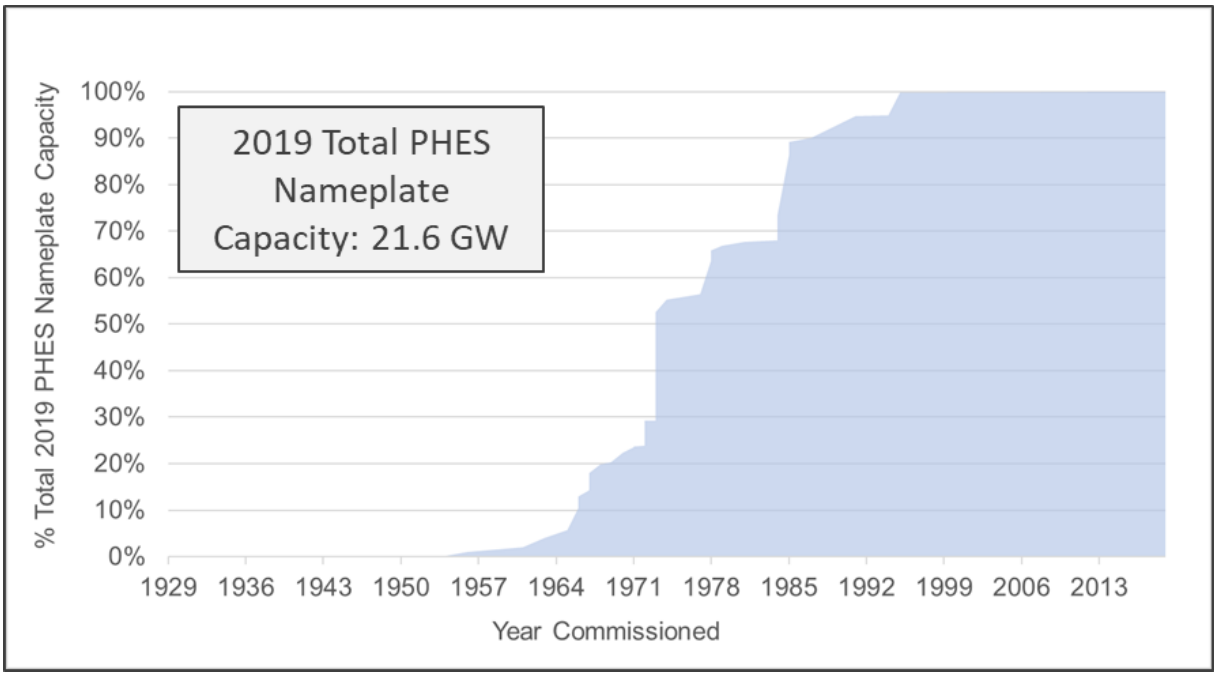


**Figure 1-1:** Growth of US PHES Capacity (USDOE, 2018)[1]

With the PHES capacity owned and operated under the vertically integrated utility model dominant at the time, mechanisms beyond the standard cost-of-service model were also not needed to compensate PHES participation in wholesale markets (FERC, 2010). The size, capacity and siting flexibility provided by newer storage technologies, in

[1] Commissioning dates for the Hiwassee Dam and the Rocky Mountain Hydroelectric Plant were not included in (USDOE, 2018), and were separately obtained (EIA, 2019b).

addition to lower capital costs, allowed these new storage classes to potentially inhabit any of the traditional electric system asset categories (i.e., generation-, transmission-, and distribution-level) in addition to serving in roles usually attributed to system loads.

The Commission subsequently undertook several rule making efforts impacting electric storage resource participation in wholesale markets, presumably informed by the insights gleaned from the 2010 Request for Comments. These efforts, while steps in the right direction to removing barriers to such participation, essentially nibbled around the edges of the physical and operational capabilities of electric storage resources. Specifically, two resulting final rules addressed storage resource compensation (FERC, 2011c, 2013a) for ancillary services only. A third rule was limited to including electric storage devices in the *pro forma* interconnection agreements and procedures for Small Generators (FERC, 2013b), defined as “devices used for the production of electricity having a capacity of no more than 20 megawatts” (FERC, 2005).

### 1.2 Intervening Energy Storage Innovations and Evolution: 2010 – 2016

The intervening years had seen continued changes related to electric storage: (1) a range of cost-effective electric storage projects became operational from 2010-2016 leveraging a variety of storage technologies, (2) state-level mandates for storage procurement had been implemented in various states, and (3) an evolving realization of electric storage’s capability to facilitate increased renewable energy penetration. Specific examples of these changes are further detailed below.

Commissioning of New Commercial Storage Technologies

Figure 1-2 provides an overview of evolving distribution of storage technologies that was being commissioned in the US between 2010 and 2016. The total nameplate storage capacity only increased by approximately 10% over this period. At the same time, new categories of storage technologies, as well as new variants of existing storage technology categories became sufficiently mature to achieve commercialization.

While each still represented less than 1% of the nation's 2016 electric storage capacity, flywheel (mechanical and concentrated solar generation coupled with molten salt storage projects both moved from demonstration stages into the realm of larger-scale commercialized assets. Advances in materials science (e.g., carbon fiber rotor fabrication) and flywheel design enabled the commissioning of flywheel facilities with up to 20 MW capacity in New York and Pennsylvania starting in 2011. Only two years later, new heat transfer fluids (i.e., molten salts) were deployed in 2013 in the first operational US commercial concentrated solar facility to be coupled with storage in order to provide more reliable energy supply through all hours of the day.

Introduction of battery storage followed a somewhat different path, but the maturing of relevant technologies still resulting in the converging introduction of new commercial storage resources during the early 2010's. Batteries providing storage in the form of electrochemical energy were available prior to the creation of the US electric grid in the late nineteenth century; rechargeable lead-acid batteries were first invented in 1859, whereas Edison's Pearl Street Station, the first commercial central power state in the US, began generation in 1882. However, there are limited examples prior to 2010 where such batteries were used in larger-scale generator-type roles. In such cases,

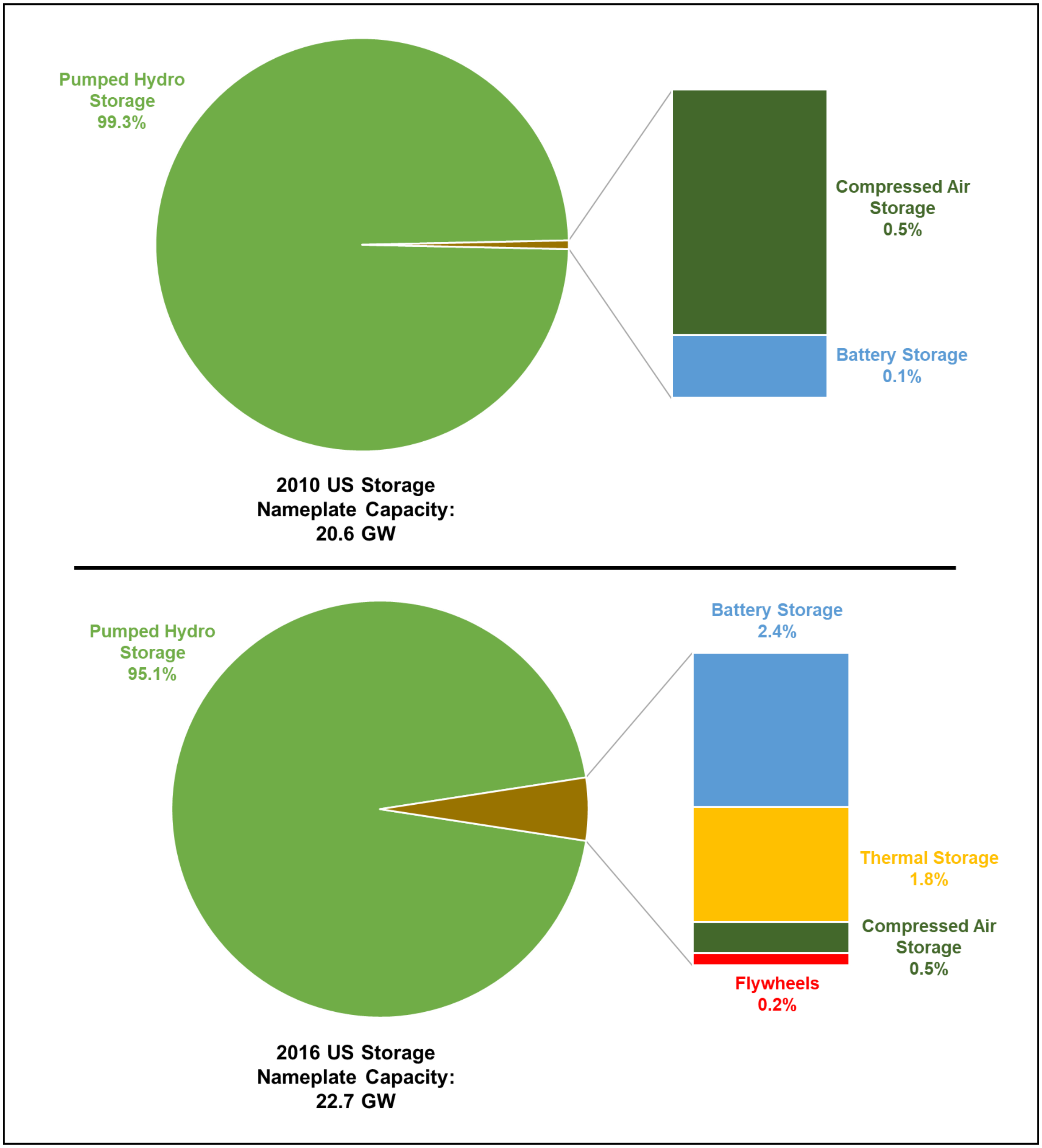


**Figure 1-2:** Comparison of 2010 and 2016 Operational US Storage Capacity (EIA, 2010, 2016b)

storage media based on lead-acid and sodium-sulfur chemistries were the primary type of battery technology employed. With the maturity of lithium-based batteries after 2010, the majority of new storage resource installations in the US, covering a wide range of facility capacities, have utilized a variety of lithium-based technologies. Other battery storage technologies have also been commercialized (e.g., flow batteries), but lithium-based batteries have truly come to dominate the battery storage landscape, representing almost two-thirds of current operational battery installations (DOE database).

State-Level Storage Mandates

From 2010 through early 2018, state-level legislative action began to focus on the introduction of storage procurement targets. These legislative efforts were aimed at state entities authorized to regulate aspects of the state electricity markets, and typically took the form of directives to assess the benefit of storage procurement mandates, and where deemed necessary, to establish specific target procurement levels and timelines. As detailed in Table 1-1, by the end of 2017, five states had either tasked their state regulatory boards with assessing procurement targets or targets had been established, with achievement of the targets occurring no later than 2020.

Facilitation of Higher Renewable Energy Penetration Levels

During this period, a variety of real-world experiences provided a window into the needs of an electric grid attempting to achieve high levels of renewable energy penetration. Renewable generation resources such as wind and solar generation require the introduction of additional levels of system flexibility to counterbalance the intermittent nature of the associated generation (Kristov, 2015). Conventional electric grid elements

**Table 1-1:** State-Level Electric Storage Legislation and Mandates Enacted Prior to 2018

| State | Legislative Bill | Effective Date | Mandate Details | Reference |
|---|---|---|---|---|
| California | AB2514 | Sept 29, 2010 | California Public Utilities Commission (CPUC) is directed to determine appropriate targets for each load-serving entity to procure energy storage systems to be achieved by 2015 and 2020<br>CPUC set procurement target of 1325 MW by 2020 | (AB2514, 2010)<br>(CPUC, 2013) |
| | AB2868 | Sept 26, 2016 | The CPUC can approve up to 500 MW of distribution-connected or behind-the-meter (BTM) energy storage.<br>No more than 25% of energy storage capacity can be provided by BTM energy storage | (AB2868, 2016) |
| Oregon | HB2193 | Jun 10, 2015 | Electric companies with at least 25000 retail customers to procure one or more energy storage system with a capacity of at least 5MWh energy by Jan, 2020 | (HB 2193, 2015) |
| Massachusetts | H.4568 | Aug 8, 2016 | Department of Energy Resources is directed to determine whether to set January, 2020 procurement targets for energy storage systems | (H. 4568, 2016) |
| Nevada | SB204 | Jul 1, 2017 | Nevada Public Utilities Commission is directed to determine, on or before October 1, 2018, whether to establish biennial energy storage procurement targets | (SB204, 2017) |
| New York | AB6571 | Mar 9, 2017 | New York Public Service Commission is directed to set a 2030 target for storage procurement<br>Set a target of 1325 GW by 2020. | (A6571, 2017)<br>(NYDPS, 2018) |

can be leveraged to provide generation- or transmission-related flexibility. For example, Germany’s energy transition efforts (i.e., Energiewende) enable generation of 27% of all electricity from renewable sources by 2014, while continuing to work towards supplying 80% of electricity from renewable sources (Pollitt & Anaya, 2016). In this case, system flexibility was provided by leveraging existing robust transmission capacity to neighboring countries that accommodated export of excess generation and reduced the need to curtail wind and solar generation.

Conversely, regions with existing constraints preventing over-reliance on such conventional solutions must instead seek alternate approaches to ensuring sufficient grid flexibility is maintained as the transition to greater renewable energy occurs. Introduction of electric storage resources is one path that can be taken to provide sufficient system flexibility. New York State’s launch the Reforming the Energy Vision in 2014 (New York State, 2019) provides such an example. Seeking to create a cleaner, more resilient and affordable energy system for New York, the program has established a target to obtain 50% of all electricity from renewable energy sources by 2030. However, significant transmission constraints exist within the state, preventing the abundant upstate, zero-emission resources from being available for use in the downstate region where fossil fuels generation provided close to three quarters of all electricity generation in 2016 (NYISO, 2017). One approach that New York taken to address reliability concerns associated with high renewable energy penetration was to explicitly include energy storage procurement targets in their planning to achieve the 2030 renewable energy goals.

### 1.3 Issuance of Order No. 841

The Commission found itself concurrently engaged in issuing orders on a case-by-case basis that impacted aspects of electric storage wholesale market participation (FERC, 2016)[2]. The final rules pertaining to storage resource compensation for ancillary services mentioned above are two such examples (FERC, 2011c, 2013a). Also, some Independent System Operators (ISO's) and Regional Transmission Organizations (RTO's) had independently begun work on wholesale market tariff updates that would permit broader electric storage resources to provide a broad range of grid services[3]. In whole, these technical, regulatory and economic developments caused concern within FERC that storage resources were facing "barriers that limit them from participating in organized wholesale electric markets" (FERC, 2016)[4].

Moving forward to November 2016, FERC issued a Notice for Proposed Rulemaking (NOPR) seeking to address a broader, more ambitious goal; a general effort to remove barriers to participation of electric storage resources in organized wholesale electric markets (FERC, 2016)[5]. Following receipt of stakeholder comments on the proposed rule elements in the NOPR and the subsequent rule draft, the Final Rule, as detailed in Order No. 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators), was published in the

[2] At Paragraph 6

[3] As will be discussed in Chapter 4, the California Independent System Operator (CAISO) had worked for a number of years on developing the new Non-Generator Resource (NGR), which was designed specifically for energy storage resources.

[4] At Paragraph 7

[5] The 2016 Notice of Proposed Rulemaking also sought to remove barriers to wholesale electricity market participation of distributed energy resource aggregations. FERC indicated in the Final Rule for Order No. 841 that further efforts to define rules for aggregations would be moved to a separate docket, as discussed in Section 2.4: Key Out-of-Scope Topics

Federal Register on March 6, 2018, and became effective on June 4, 2018 (FERC, 2018). In line with the compliance requirements, RTO/ISO's were required to submit compliance plan six months after the Final Rule's effective date to demonstrate that their proposal will satisfy the associated requirements. RTO/ISO's are then permitted twelve months after the compliance plan filing to implement their respective proposed market reforms detailed in the plans.

### 1.4 Research Topic Overview

The goal of this project is to begin to develop an understanding of the potential impact that Order No. 841's Final Rule will have on the participation of electric storage resources (ESR) in US wholesale electricity markets. This is a timely topic, given that the Order only became effective within the past year, and RTO/ISO's have yet to receive approval of the compliance plans submitted in early December, 2018.

The method by which this understanding can begin to be established will consist of analyzing the components of the Order, the Commission's exercise of its authorized jurisdiction within the Order, and the actions taken by the RTO/ISO's and FERC to demonstrate compliance with the Final Rule requirements:

1. ***Final Rule Requirements and Participation Model Effectiveness***: The key requirements contained within the Final Rule will be outlined. This assessment will be accompanied by a consideration of unresolved topics determined to be out of scope of the Final Rule that may represent significant future challenges to the envisioned electric storage participation. The use of participation models as a means of enabling optimal provision of grid services by electric storage

resources will be reviewed in order to the determine the likelihood of the Final Rule being suitable for its intended purpose.

2. ***Final Rule Legal Foundations and Jurisdictional Perspectives***: FERC's jurisdictional claims outlined in the Final Rule will be identified and discussed in the context of relevant precedents, including previous judicial decisions and similar Commission-issued rules.  The ability of FERC's approach to jurisdictional claims to provide a sustainable regulatory regime will be discussed along with potential challenges faced by the modern electric grid arising from such approaches.
3. ***RTO/ISO Compliance Plans and Initial Commission Responses***: Key aspects of the recently proposed compliance plans will be summarized to identify and categorize approaches taken to achieve compliance with the Final Rule by the RTO/ISO's.  These plans will also be reviewed in the context of the compliance deficiency letters recently issued by FERC as an avenue to gain insight on the likely viability of the proposed plans.

It is critical to broaden the understanding of the viability and impact of these Order-driven changes on the rate of ESR adoption, and by extension, increased renewable energy penetration on a national level.  This interaction amongst resilience of the Final Rule requirements, wholesale market participation and continued ESR adoption is therefore of interest to all stakeholders impacted by renewable energy resource adoption: ESR developers and owners, energy policy and regulatory bodies at the state and federal levels, energy customers, and transmission/distribution/generation system owners.

# Chapter 2 Overview of FERC Order No. 841

## 2.1 Introduction

An understanding of the elements of Order No. 841, is critical to assessing the impact it will have on the adoption of electric storage resources in the US electric system. However, such Orders provided by the Commission are not just a simple prescriptive list of instructions for impacted entities to follow. The Orders also provide key stakeholder comments taken into consideration when formulating the Commission's determinations on specific aspects of the Order. Additional interpretive details and clarifications are typically provided to aid in the execution the Order's requirements. Such additional information serves as a demonstration that the associated prescriptions are neither arbitrary nor capricious (i.e., avoiding the risk of subsequent judicial review for lawfulness), while enabling consistent compliance by entities falling within FERC's jurisdiction on the relevant matters.

Despite such intentions, the richness of content present in many of the Commission's Orders can be daunting to more casual readers, or obscure critical details central to a more focused analysis. In an effort to establish a relatively concise foundation on which subsequent analytical discussions will be built, an initial summarization and classification of the Order's elements provides a beneficial first step towards achieving the current study's goals. As such, this chapter will provide a summary of: (1) the elements and requirements of Order No. 841, and (2) key unresolved items related to future storage resource participation. Additionally, the modes by which FERC's focus on participation models in the Order can impact energy storage capacity deployment will be discussed.

## 2.2 Tariff Revisions and Participation Models

At a high level, the Final Rule issued in Order No. 841 (referred to subsequently in this Chapter as the "Final Rule") simply requires an update to existing tariffs maintained by the nation's RTO's and ISO's by incorporating an additional participation model. With this in mind, the roles of tariffs and participation models, as used in wholesale electric markets, deserve some further discussion.

RTO/ISO's maintain tariffs that outline provided services, rates and charges for those services, and rules and regulations affecting these services, rates and charges. These tariffs are required to be filed with, and are subject to hearings for lawfulness by FERC (Federal Power Act, 1935). It is within these tariffs that the RTO/ISO's set forth wholesale market operational and participation procedures for defined services. The Final Rule explicitly revises FERC regulations to require RTO/ISO's to update their current tariffs to include market rules facilitating participation of a new resource: Electric Storage Resource.

In the context of wholesale electric markets, FERC refers to participation models as tariff provisions that are applicable to a specific class of resources. These provisions are included when a class of resources requires distinctive treatment in order to accommodate or leverage its unique physical or operational characteristics (FERC, 2018)[6]. The Commission views implementation of such models as a mechanism for

[6] At Paragraph 3

removing barriers to participation, enhancing competition, and ensuring just and reasonable prices (FERC, 2018)[7].

Four required elements of the participation model were stipulated within the Final Rule. These elements are summarized in Table 2-1. An additional general tariff revision was also stipulated that is related to the prices at which ESR's are to be charged for energy purchased for later resale within the wholesale market.

**Table 2-1:** ESR Participation Model Elements

| **Element Name** | **Element Description** |
|---|---|
| Service provision eligibility | Assurance of ESR eligibility to provide all wholesale market services (i.e., energy, capacity and ancillary services) that it is technically capable of providing |
| Wholesale market price setting | Assurance that ESR's can be dispatched and set the market price as the marginal energy injecting of withdrawing resources (i.e., as both a buyer and a seller of electric market services) |
| Market bidding parameters | Accounting for physical and operational characteristics of the ESR in market bidding parameters |
| Minimum resource size | Establishes a minimum resource capacity, above which RTO/ISO's must allow qualifying resources to use the ESR participation model |

### 2.2.1 ESR Definition, Qualification and General Participation

The first required element of the ESR participation model focuses more on the basic aspects of ESR's and foundational concepts to be achieved by the participation models. The key aspects of this element include: (1) defining an ESR, (2) outlining requirements

[7] At Paragraph 4

to qualify a resource as an ESR, (3) an understanding of technical capability within the context of the Final Rule, and (4) the relationship between various participation models that may already be available to storage resources.

ESR Definition

Prior to proscribing detailed elements of the new participation model, the Final Rule establishes an explicit definition for ESR's to clarify which resources may utilize the associated participation model (FERC, 2018)[8]. The Final Rule thus provides the following definition:

**Electric Storage Resource**: *A resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.*

Incorporated within this definition are two implied elements. First, the definition lacks any mention of underlying storage technology or medium, but instead focuses only on the capability to withdraw, store and inject energy to the grid. Thus, this effectively technology-agnostic definition should remain relevant as new storage technologies are developed and commercialized. Second, the definition does not proscribe the location in which an ESR can reside within the electric system. Any storage resource, whether interconnected at the transmission-, distribution- or behind-the-meter-level, is capable of meeting the ESR definition and utilizing the corresponding participation model for wholesale electricity sales. However, while providing wholesale market participation opportunities for a wide range of storage resources, as will be discuss in Chapter 4, this

[8] At Paragraph 29

element of the definition may introduce jurisdictional challenges in execution of the Final Rule.

Having the ability to both withdraw and inject energy to the grid are central to the ESR definition. To emphasize this, the Final Rule clarifies that even resources capable of both operations, if constrained by its operational configuration or contractual obligations to only withdraw or inject energy to the grid, would not meet the elements of the ESR definition (FERC, 2018)[9]. Indeed, the Final Rule points out the specific instance of behind-the-meter storage resources capable of only withdrawing energy that would not qualify as ESR's, but rather demand response resources for which distinct participation models are already available (FERC, 2008b, 2011b).

ESR Qualification

The Final Rule also requires tariffs to include qualification criteria that provide clear eligibility requirements for wholesale market participation as an ESR. In alignment with the ESR definition, these qualification criteria need to be based on the physical and operational attributes of a resource, in addition to assuring resource dispatchability corresponding to these attributes (FERC, 2018)[10]. Beyond an expectation that qualification criteria themselves not introduce barriers to market participation, greater proscriptive requirements on the criteria were avoided with the intention of providing RTO/ISO's with a degree of flexibility to ease incorporation of the ESR participation model into their varied wholesale market structures (FERC, 2018)[11].

[9] At Paragraph 32
[10] At Paragraph 61
[11] At Paragraph 62

Technical Requirements to Provide Services and ESR Capabilities

The Final Rule repeatedly emphasizes the need for ESR participation models to allow such resources to offer services that they are technically capable of providing. This range of service is quite expansive, including services procured through organized competitive markets (i.e., energy, capacity and ancillary services) and services not currently procured through such mechanisms (e.g., black start service, primary frequency response, reactive power, etc.), with all service provision requiring compensation commensurate with the service provided (FERC, 2018)[12]. One could question whether introduction of a new participation model will introduce an unwarranted preference to procure services from ESR's. On the contrary, the Final Rule's stated goal is to simply remove barriers to ESR participation, thereby enhancing competition among all resources that are technically capable of providing a given service (FERC, 2018)[13]. There are no general requirements to modify technical requirements that resources need to meet to provide specific services. ESR's instead must be capable of meeting all existing technical requirements, presumably applicable to all other potential service providers, to ensure reliable provision of such services (FERC, 2018)[14].

An allowance provided to ESR's to meet specific technical requirements for services is the ability to de-rate its capacity, relative to the rated nameplate capacity, in order to meet minimum run-time requirements, primarily for providing capacity services (FERC,

[12] At Paragraph 70
[13] At Paragraph 52
[14] At Paragraph 77

2018)[15]. As an example, a unit capable of storing 1000 kWh of energy providing power at its nameplate rating of 500 kW can provide this power for up to 2 hours. De-rating would allow the unit to offer a lower power output so that it could meet longer run-times (e.g., 250 kW output for 4 hours) typically needed to meet the technical requirements of various services. This allowance therefore leaves in place the technical requirement needed to ensure reliable provision of given service, in this case capacity, while permitting ESR participation that is reflective of the resource's operational and physical characteristics (i.e., the ability to deliver its full energy capacity at lower power).

Relationship Between ESR's and Other Participation Models

Neither participation as an ESR nor wholesale market participation in general is required of potentially qualifiable storage resources under any mandates within the Final Rule; both actions are voluntary (FERC, 2018)[16]. In an effort to avoid unnecessary disruptions to the RTO/ISO's and resource owners, the Final Rule clarifies that any existing participation models already available to storage resources (e.g., for pumped hydroelectric storage or demand response) need not be consolidated with the newer ESR model. Therefore, storage resources are free to continue operating under participation models to which they were previously qualified for, if so desired. Qualifying storage resources may also choose to not be a direct party in wholesale market transactions. The Final Rule clarifies this allowance with at least an implicit understanding that some resource owners may not wish to bear the burden of meeting

[15] At Paragraph 93
[16] At Paragraph 55

the wholesale market participant responsibilities[17] called for in FERC's rules and regulations.

### 2.2.2 Roles and Dispatch of ESR's

Having established the required core elements of what is to be considered an ESR, the Final Rule proceeds to outline details of the second element of the corresponding participation model. These details are largely related to roles ESR's may play in providing specific services, the associated dispatch process, and ESR compensation for non-economic dispatch.

<u>ESR Roles in Service Provision</u>

Most elements of the electric system are capable of either primarily injecting or withdrawing energy from the grid. These system elements would then inhabit the roles of either supply or demand (i.e., load), respectively, in electric markets. Given the capabilities of storage resources permitting both electricity withdrawal and injection, ESR's have the flexibility to play both supply- and demand-type roles in wholesale markets. Recognizing this flexibility, the Final Rule provides clear requirements that the participation models must ensure the ability of ESR's to be dispatched by RTO/ISO's as either a supply or demand in wholesale markets (FERC, 2018)[18]. As an extension to this dispatchability requirement, the participation models need to include the ability of

[17] As stated in footnote 50 of the Final Rule (FERC, 2018), regulated responsibilities of participating resources may include filing rates, submitting information related to corporate activities and fulfilling accounting obligations, as dictated in the FPA.
[18] At Paragraph 140

dispatched ESR's to set market clearing prices, consistent with existing market price setting rules, through both wholesale market buyer and seller bids.

ESR Dispatch Process

One challenge faced by an ESR's dual roles is avoiding conflicting dispatch instructions with the same market interval, as this may introduce operational uncertainties or reliability concerns (FERC, 2018)[19]. It is possible to reduce the likelihood of such conflicting signals by avoiding requirements for ESR to provide simultaneous supply and demand bids for a given market interval or through appropriate design of bid parameters. Flexibility is provided to the RTO/ISO's to address residual operational risks resulting from conflicting bid and dispatch signals in a given market interval. Nevertheless, the RTO/ISO's are required to demonstrate in their tariff update proposals how existing or modified market design and rules prevent such conflicts.

Out-of-Merit Order Dispatch Compensation

A second consideration detailed in the Final Rule pertains to make-whole (i.e., uplift) payments to ESR's dispatched out of merit order. Such non-economic dispatch can occur to address system reliability, system congestion or to accommodate resource operational characteristics (Bresler, 2014), with the extent of such dispatch depending on specific electric system and market design features (Bresler, 2014; Pavic, Dvorkin, & Pandžic, 2019). ESR participation models must allow make-whole payments when an ESR is dispatched to provide supply at a market price below the resource offer price, as is typically done for other resources subject to out-of-merit order dispatch (FERC,

[19] At Paragraph 160

2018)[20]. Additionally, since ESR's can serve as dispatchable demand (i.e., load) resources, the ESR participation models must allow make-whole payments when ESR's are dispatched to withdraw energy at a market price above the resource's bid price (FERC, 2018)[21]. These dual-direction make-whole payments, unique to ESR participation models, are considered necessary to ensure ESR's are treated like other dispatchable resources, while also removing potential economic disincentives when dispatched to address reliability concerns.

### 2.2.3 ESR Market Bidding Parameters and State of Charge Management

RTO/ISO's use a variety of information to calculate economically-optimized dispatch schedules for system resources. As an example, traditional generators submit bid curves to communicate the quantities of energy they are willing to provide at a given price for specific market intervals. The RTO/ISO's risk developing dispatch schedules that, while economically optimal, may be infeasible to execute due to a lack of accounting for physical and operational constraints of the dispatched resources. Generators thus provide a variety of additional bidding parameters (e.g., ramping rates, minimum run times, etc.) reflective of their specific operational characteristics that the RTO/ISO utilize to develop feasible dispatch schedules.

Application of existing bidding parameters used for traditional generation resources, or for participation models developed around provision of a narrow set of services (e.g., frequency regulation, demand response, etc.), would limit ESR market participation to providing limited services or risk infeasible dispatch instructions. Both outcomes would

[20] At Paragraph 174
[21] At Paragraph 175

inhibit an ESR's wholesale market participation where the resource would have been technically capable of providing such services without introducing reliability issue to the electric system.

Identifying this source of participation barriers for ESR's, the Final Rule includes a third required element for the ESR participation models: inclusion of market bidding parameters reflecting the physical and operational characteristics of ESR's. As outlined in Table 2-2, thirteen bidding parameters related to ESR charge states and ramping, operational durations, and service procurement efficiency were defined for inclusion in the ESR participation models (FERC, 2018)[22]. ESR's would be permitted to submit bidding parameters in both the day-ahead and real-time markets, along with the ability to update parameter values needed by RTO/ISO's to find accurate dispatch solutions (FERC, 2018)[23].

The Final Rule does provide a great degree of flexibility to RTO/ISO's to ensure that the physical and operational characteristics of ESR's are accounted for, having recognized that unique market designs may enable alternate effective ways of executing this accounting (FERC, 2018)[24]. RTO/ISO's are also allowed discretion to determine whether submission of any information for specific bidding parameters is obligatory.

[22] At Paragraphs 178-231
[23] At Paragraph 189
[24] At Paragraph 187

**Table 2-2:** Overview of Required ESR Bidding Parameters
(FERC, 2018)

| Bidding Parameter Category | Physical/Operational Characteristic | Parameter Definition | Parameter Functions and Details |
|---|---|---|---|
| Charge States and Rates | State of Charge | Amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage. It represents the forecasted starting State of Charge for the market interval being offered into. | • Reflects actual operating conditions of resource<br>• Provides greater certainty to RTO/ISO on ESR capability<br>• Telemetered in real time<br>• ESR owner may elect self-management (default) or RTO/ISO management |
| | Maximum State of Charge | State of Charge value that should not be exceeded (i.e., gone above) when an ESR is receiving electric energy from the grid | • Places limits on extent RTO/ISO can charge/discharge ESR<br>• Ensures operation within design limits<br>• Provision of static or dynamic values should be allowed |
| | Minimum State of Charge | State of Charge value that should not be exceeded (i.e., gone below) when an ESR is injecting electric energy onto the grid | |
| | Maximum Charge Limit | Maximum MW quantity of electric energy that an ESR can receive from the grid | • Similar to traditional economic maximum (highest output available for economic dispatch) |
| | Maximum Discharge Limit | Maximum MW quantity of electric energy that an ESR can inject onto the grid | |

**Table 2-2:** Overview of Required ESR Bidding Parameters (cont'd)
(FERC, 2018)

| Bidding Parameter Category | Physical/Operational Characteristic | Parameter Definition | Parameter Functions and Details |
|---|---|---|---|
| Operational Durations | Minimum Charge Time | Shortest duration that an ESR is able to be dispatched to receive electric energy from the grid | • Potentially more applicable to resources with slow transition speeds<br>• Similar to traditional Minimum Run Time, but reflects ESR withdrawal duration |
| | Maximum Charge Time | Maximum duration that an ESR is able to be dispatched to receive electric energy from the grid | • Prevents charging dispatch exceeding Maximum State of Charge (self-managed State of Charge)<br>• Provides info on reliable withdrawal duration (self-managed State of Charge) |
| | Minimum Run Time | Minimum amount of time that an ESR is able to inject electric energy to the grid | • Prevents ESR wear and tear due to frequent start/stop<br>• Ensures start-up costs are recoverable<br>• Similar to traditional Minimum Run Time |
| | Maximum Run Time | Maximum amount of time that an ESR is able to inject electric energy to the grid | • Maximum discharge time due to physical, operational or contractual constraints |

**Table 2-2:** Overview of Required ESR Bidding Parameters (cont'd)
(FERC, 2018)

| Bidding Parameter Category | Physical/Operational Characteristic | Parameter Definition | Notes |
|---|---|---|---|
| Improved Service Procurement Efficiency | Minimum Discharge Limit | Minimum MW output level that an ESR can inject onto the grid | • Limits may result from physical constraints/power electronics |
| | Minimum Charge Limit | Minimum MW level that an ESR can receive from the grid | |
| | Discharge Ramp Rate | Speed at which an ESR can move from zero output to its Maximum Discharge Limit | • Reflects possible difference in rates to achieving Maximum Discharge/Charge Limits<br>• Similar to traditional Ramp Rate |
| | Charge Ramp Rate | Speed at which an ESR can move from zero output to its Minimum Charge Limit | |

The parameters were designed for a wide range of storage resource characteristics, some of which might not be applicable to specific storage technologies and configurations (FERC, 2018)[25], State of Charge oversight (see below) or ESR commercial obligations (FERC, 2018)[26].

State of Charge Management

Requirements related to the management of an ESR's state of charge and, by extension, the values of the related bidding parameters, are also included in the Final Rule. Specifically, ESR owners must be allowed to self-manage the state of charge of their respective resources (FERC, 2018)[27]. RTO/ISO's are still permitted to have mechanisms to manage ESR state of charge, but election for such management must remain optional and require ESR owner opt-in (e.g., self-management is the default operational state).

Self-management is advantageous for a variety of reasons, but it also comes with increased performance accountability for the ESR owners and operators. Owner, presumably having best understanding of the long-term operation and instantaneous state of their storage resource, may be able to better optimize resource operation than RTO/ISO's, especially when providing a variety of service types. Self-management may also reduce wear and tear on the ESR through better attention to critical operational limits (FERC, 2018)[28]. For example, violation of ESR Minimum and Maximum States of Charge levels can lead to significantly shortened resource lifetime or lead to hazardous

[25] At Paragraph 188
[26] At Paragraph 207
[27] At Paragraph 246
[28] At Paragraph 247

operating conditions for some storage technologies. Real time telemetry may mitigate some of this risk in the case of RTO/ISO state of charge management, but operators still carry some residual risk of sub-optimal resource operation due to telemetry failures or inaccuracies.

Some advantages can be had from RTO/ISO management of ESR state of charge. ESR owners are fully accountable for not meeting performance requirements when self-managing, and are subject to performance-based penalties when not meeting dispatch schedules (FERC, 2018)[29]; RTO/ISO management of state of charge exempts the ESR owner from these potential penalties. Additionally, since resource owner have a greater capability to intentionally manipulate market conditions through physical or economic withholding when self-managing state of charge, market monitoring scrutiny may be expected to be commensurately greater (FERC, 2018)[30]. RTO/ISO management could relieve some of this monitoring pressure. Lastly, RTO/ISO state of charge management could actually improve the ability of ESR's to provide select services (e.g., frequency regulation) due to unique technical requirements of those services (FERC, 2018)[31].

### 2.2.4 Minimum Size Requirements

As the commercialization of newer storage technologies advances, the US electric system has seen the scale of proposals for such storage resources approaching that of traditional generation resources. For example, Pacific Gas & Electric recently received approval from the CPUC for two battery storage projects, one for 180 MW and a second

[29] At Paragraph 246
[30] At Paragraph 252
[31] At Paragraph 246

at 300 MW, to replace retiring gas generators (CPUC, 2018). However, as shown in Figure 2-1, most storage resources operational in the US starting after 2000 have nameplate capacities ranging from less than 1 MW up to approximately 20 MW (EIA, 2017b), which are significantly smaller than that of other electric system resources.

Most existing participation models include minimum size requirements, but those were implemented prior to the emergence of smaller scale technologies utilized for storage resources (FERC, 2018)[32]. Use of existing minimum size requirements would therefore prevent most storage resources from participating in wholesale markets. In an effort to remove the source of barriers to ESR participation, the Final Rule provided a fourth required element for the participation model, stipulating a minimum resource size for ESR's using the associated participation model.

A minimum resource size of 100 kW is mandated for the ESR model, and is to be utilized for all capacity requirements and minimum energy injection/withdrawal bidding quantities (FERC, 2018)[33]. This limit represents a balancing of two considerations. First, the Commission has acknowledged the challenges faced by RTO/ISO's with determining dispatch solutions as the allowed resource size decreases (FERC, 2018)[34]. At the same time, all RTO/ISO's have demonstrated the ability to accommodate resources small resource capacities; each has at least one existing participation model allowing resources as small as 100 kW (FERC, 2018)[35].

[32] At Paragraph 266
[33] At Paragraph 265
[34] At Paragraph 266
[35] At Paragraph 267

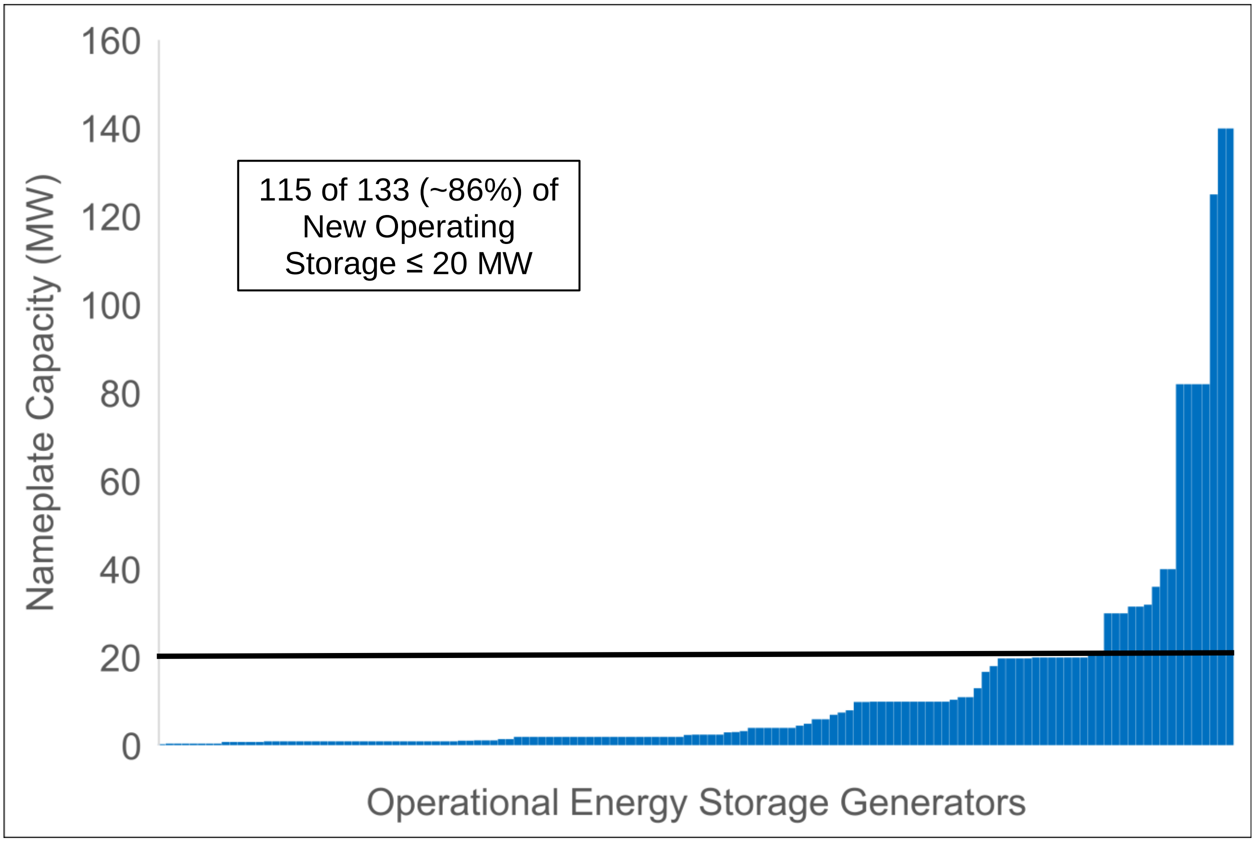


**Figure 2-1:** Newly Operational Energy Storage Generators (2000 – 2018)

*Note:* Each bar represents the nameplate capacity of a single operating generator using storage-based technology listed in (EIA, 2017b). Generators using storage-based technology include Batteries, Flywheels, Hydroelectric Pumped Storage, and Solar Thermal with Energy Storage.

### 2.3 Energy for ESR Charging

Storage resources have multiple options for obtaining energy for charging. Storage resources coupled with on-site generation (e.g., solar-plus-storage projects) can be charged directly from generation in excess of on-site demand. Alternatively, charging can occur with energy purchased from the grid. Stored energy providing end-use services to the resource owner would be procured via retail transactions, and are clearly outside the Commission's scope (See Chapter 3). Energy purchased from the grid for charging, where the stored energy will later be injected back to the grid for resale, would occur via a wholesale transaction. The characterization of such purchases as occurring through wholesale markets had been established over 20 years prior to the issue date of Order No. 841 in the case of pumped air storage facilities (FERC, 1995). The Commission found that this characterization was now broadly applicable to energy purchased to charge ESR's injecting energy back to the grid for later resale (FERC, 2018)[36].

The prices of energy purchased for later resale consist of multiple standard components, including the incremental cost of the energy, transmission constraints present at the point of purchase and transmission losses. Thus, the wholesale prices charged to conventional loads can vary significantly depending on the load's location on the grid and the transmission constraints experienced at that location (ISO-NE, 2019a). This composite price is referred to as a wholesale locational marginal price (LMP), and is the wholesale energy price paid by conventional loads. The wholesale LMP can reflect either the specific location, or node, at which the location is connected to the grid (i.e., nodal LMP), or across a zone representing an aggregation of pricing nodes (i.e., zonal LMP).

Accordingly, the Final Rule requires that ESR's be charged the wholesale LMP, specifically the nodal LMP (FERC, 2018)[37], for such whole energy purchases, just as any other load would be charged when purchasing energy for later resale. While the energy price requirement is applicable to storage resources using the ESR participation model, the Final Rule clearly indicates the ability of storage resources to be charged the wholesale LMP is not derived from the use of any specific participation model;

[36] At Paragraph 289
[37] At Paragraph 291

applicability of wholesale LMP's arises solely from the wholesale nature of the transaction (FERC, 2018)[38]. Therefore, a resource meeting the Final Rule's definition of an ESR is entitled to purchase energy for later resale at the wholesale LMP, regardless of whether it is using the ESR participation model required by The Final Rule, or some other participation model. Additionally, this requirement to allow purchase of charging energy at the wholesale LMP applies to ESR's interconnected at all levels of the electric system, (i.e., transmission-, distribution and behind-the-meter-connections).

As detailed above, energy used for ESR's charging can come from a variety of sources and be applied to different uses (e.g., retail vs. wholesale activities). The Commission finds it critical that RTO/ISO's be able to reliably differentiate between and account for these activities to ensure wholesale energy sales for ESR charging occur at the wholesale LMP. As such, the Final Rule requires some form of direct metering of ESR's, or other comparable means of enabling proper accounting of wholesale energy purchases of ESR charging, to ensure proper application of wholesale LMP charges (FERC, 2018)[39]. It is recognized that this requirement may be difficult to address, and may require close coordination with distribution utilities and regulatory bodies possessing jurisdiction over the distribution portions of the electric grid (FERC, 2018)[40].

Related to wholesale energy purchases and withdrawals, the Final Rule seeks to further provide equivalent treatment of ESR's and more traditional electric system elements. The issue of transmission charges is specifically addressed for the two scenarios where

[38] At Paragraph 289
[39] At Paragraph 317
[40] At Paragraph 319

ESR's purchase energy for later resale.  First, ESR wholesale energy purchases intended for simply charging and later resale are identical in nature to load-related withdrawals executed by load-serving entities (LSE) (FERC, 2018)[41].  Given this identical nature, ESR's are thus deemed to have an identical liability for related transmission charges imposed on LSE's.  Second, when dispatched to provide services requiring energy withdrawal from the grid (e.g. ancillary services), ESR's would not be responsible for paying transmission charges; this treatment is consistent with that of traditional generators providing ancillary services (FERC, 2018)[42].

## 2.4 Key Out-of-Scope Topics

Throughout the process leading up to issuance of the Final Rule, a variety of topics were within the scope of consideration, but were ultimately identified as being out of scope of this Final Rule (FERC, 2018)[43].  These topics arose either through proposals made by FERC or through stakeholder comments submitted in response to the associated NOPR and the proposed form of the Final Rule.  This list of topics explicitly deemed out of scope of the Final Rule is quite long, consisting of over 20 various items.  Comprehensive review of each topic may be of limited value when assessing their general impact on removal of barriers to ESR participation in the US electric system.  However, three topics are worth a brief consideration due to their more obvious impacts on participation barriers for storage resources.  These include: (1) rules for aggregated demand response participation in wholesale electric markets, (2) expansion of ESR

[41] At Paragraph 292
[42] At Paragraph 293
[43] At Paragraph 324

participation models to wholesale markets outside of the organized markets managed by the RTO/ISO's, and (3) incorporation of ESR's into transmission planning activities.

As indicated in Section 1.3 (Footnote 5), the 2016 NOPR initially sought comments on wholesale market participation rules for both electric storage resources and aggregated distributed energy resources (DER), but further action on aggregated DER was split off into a separate docket, RM-18-9-000, prior to issuance of the Final Rule (FERC, 2018)[44]. In the context of the Final Rule, any storage resource rated at less than 100 kW would only be able to participate in wholesale electric markets through some form of aggregation mechanism allowing multiple storage resources to bid to inject or withdraw electric energy as part of wholesale transactions.

Consideration of aggregated storage resources participation may not be a critical area needing immediate attention from FERC at the current time. As shown in Table 2-3, small-scale storage projects reported to the U.S. Energy Information Administration (i.e., < 1 MW nameplate capacity) accounted for no more than 0.4% of all operational storage power capacity in the US in 2016 and 2017, the only years in which such data is available. Storage capacity not eligible to participate in wholesale electric markets under the ESR participation models represents a subset of this capacity and would make up an even smaller percentage of existing US storage capacity.

Yet future reductions in costs of storage technology amenable to systems with capacities lower than 100 kW or creation of effective subsidies for such resources could

[44] At Paragraph 5

**Table 2-3:** 2018 Electric Energy Served by RTO/ISO's

| Large-Scale Storage Resources (≥ 1 MW) | | |
|---|---|---|
| **Year** | **2016** (EIA, 2016c) | **2017** (EIA, 2017b) |
| **Technology** | **Nameplate Capacity (MW) (EIA, 2016c)** | **Nameplate Capacity (MW) (EIA, 2017b)** |
| Battery | 545.2 | 707.8 |
| Flywheels | 44.0 | 42.0 |
| Pumped Hydroelectric | 21572.7 | 21643.3 |
| Natural Gas with Compressed Air Storage | 110.0 | 110.0 |
| Solar Thermal with Energy Storage | 405.0 | 405.0 |
| Large-Scale Battery Total | 22676.9 | 22908.1 |

| Small-Scale Storage Resources (< 1 MW) | | | | |
|---|---|---|---|---|
| **Year** | **2016** (EIA, 2016a) | | **2017** (EIA, 2017a) | |
| **Sector** | **Non-Net Metered Nameplate Capacity (MW)** | **Net Metered Nameplate Capacity (MW)** | **Non-Net Metered Nameplate Capacity (MW)** | **Net Metered Nameplate Capacity (MW)** |
| Residential | 0.1 | 4.5 | 3.9 | 13.3 |
| Commercial | 32.7 | 7.6 | 42.9 | 15.4 |
| Industrial | 8.7 | 11.7 | 12.3 | 12.3 |
| Transportation | 0.0 | 0.0 | 0.0 | 0.0 |
| Direct Connection | 1.2 | N/A | 1.4 | N/A |
| Small-Scale Battery Total [a] | 66.5 | | 101.5 | |
| **% Total Storage Nameplate Capacity [b]** | **0.3** | | **0.4** | |

a. Sum of Non-Net Metered and Net Metered Nameplate Capacity

b. Small-scale storage resources as a percentage of total storage (large- and small-scale) resources change the urgency of this need. To date, FERC organized a technical conference in April, 2018 to generally discuss potential effects of DER's on bulk power systems, including considerations for future actions to address aggregated DER wholesale market participation. As of March, 2019, no subsequent Commission actions or communications have been posted to docket RM-18-9-000 related to aggregated storage resource participation.

A second deferred item, expansion of the Final Rule's scope to storage resources not residing within RTO/ISO territories, was not further considered because the original NOPR was specifically limited to reforms of the structured wholesale markets coordinated by the RTO/ISO's that fall within FERC's jurisdiction[45]. While retention of these scope boundaries in the Final Rule are understandable from a procedural view, from a practical perspective, removal of participation barriers for storage resources should be within FERC's legislated authority and responsibility regardless of which national wholesale market a resource has access to. The Commission's rationale that existing market rules presenting barriers to storage resource participation lead to unjust and unreasonable, and therefore unlawful rates would seem to be equally valid regardless of whether one considers wholesale electric markets run by the RTO/ISO's within FERC's jurisdiction or other, more local entities.

[45] ERCOT, a Regional Transmission Organization, is wholly contained within Texas, and is not synchronized with or interconnected with electric systems in other states. All wholesale transactions occurring in ERCOT's wholesale markets are intrastate sales, and are outside the authorized jurisdiction of FERC.

**Table 2-4:** 2018 Electric Energy Served by RTO/ISO's

| Transmission System Operator/ Region | 2018 Annual Energy Served/ Generation (TWh) | % of Total 2018 Energy Generation | Reference | 2017 Large-Scale Battery Power Capacity (MW)[d] | % of Total 2017 Large-Scale Battery Power Capacity |
|---|---|---|---|---|---|
| PJM Interconnection | 807 | 21 | (PJM, 2019) | 278 | 39 |
| Midwest ISO (MISO) | 684 | 18 | (MISO, 2019) | 21 | 3 |
| Southwest Power Pool (SPP) | 276 | 7 | (ERCOT, 2019a) | Not Reported | N/A |
| California ISO (CAISO) | 239 | 6 | (PowerSouth Energy Cooperative, 2019) | 130 | 18 |
| New York ISO (NYISO) | 156[a] | 4 | (NYISO, 2018a) | Not Reported | N/A |
| ISO New England (ISO-NE) | 142 | 4 | (ISO-NE, 2019b) | 23 | 3 |
| US | 3802 | 100 | (EIA, 2019a) | 708 | 100 |
| **Combined RTO/ISO Regions[b]** | **2304** | **61** | **N/A** | **452** | **64** |
| **Other Regions** | **1498[c]** | **39** | **N/A** | **256** | **36** |

a. 2018 baseline demand forecast
b. ERCOT generation and large-scale battery power capacity included: ERCOT does not fall under FERC's jurisdiction
c. Value calculated as difference between total US and Combined RTO/ISO Region generation
d. (EIA, 2018) Figure 2

The load not served by the six RTO/ISO's within FERC's jurisdiction represents a minor, but not insignificant portion of annual electricity sales to all end-use sectors (residential, commercial, industrial, transportation). As shown in Table 2-4, 39% of the 2018 annual total US sales occurred outside of these six RTO/ISO-operated markets. The large-scale battery storage power capacity installed outside of territories served by RTO/ISO's made up approximately 36% of all such capacity in 2017 (EIA, 2018). Even if future growth trends in both annual energy sales and installed storage capacity are not comparable in regions served by RTO/ISO's and those served by other entities, there will likely continue to be significant portions of the US wholesale electric markets without clearly applicable rules governing storage resource participation. FERC will therefore continue to have opportunities requiring its intervention to ensure storage resources can contribute to the achievement of increased competition and ultimately just and reasonable electricity rates in all regions of the country.

Finally, tasking RTO's and ISO's with including storage resources in transmission planning was not addressed in the NOPR, and as such, is not within scope of the proscriptions laid out in the Final Rule. The RTO/ISO's have ultimate responsibility for short-term reliability, long-term planning and expansion of the transmission system (FERC, 1996, 2000). With a relatively low penetration of storage resources at the various interconnection levels in the current electric system, risks originating from increased utilization of transmission services by storage resources is likely to be minimal at the present time. Inclusion of ESR's in transmission planning considerations may not currently be critical to maintaining transmission system reliability. Neither is it clear that such consideration may present barriers to storage resource participation.

Inclusion of storage resources in transmission planning can reasonably be expected to become more critical as larger, non-PHES storage resources become approved (see above, Section 2.2.4), presumably interconnected at the transmission-level. More challenging may be the need to closely coordinate transmission planning with distribution- and BTM-level needs if increasing numbers of storage resources located at those interconnection levels seek to participate in wholesale market transactions. Such infrastructure planning will require close interactions between, at a minimum, federal and state-level regulatory agencies with jurisdiction over the planning of the relevant portions of the electric system.

### 2.5 ESR Value Creation and Participation Model-Driven Storage Capacity Deployment

The Final Rule does not include any targeted level of ESR deployment. It simply seeks to increase competition in wholesale electricity markets and, ultimately, lower electricity rates. Increased participation of ESR's within the scope considered in the Final Rule, is viewed simply as a means to achieving these lower rates. Such an arguably narrow statement of focus should not be surprising; as discussed in Chapter 3, ensuring just and reasonable rates (i.e., lower rates achieved through increased competition) is the foundation upon which the Commission's authorized jurisdiction rests to require creation of the new participation models.

Regardless of the Order's stated focus, as new opportunities for ESR's to provide grid-related services are realized through the new participation models, there should be greater prospects for ESR to generate increasing value for a broad range of stakeholders. Depending on the nature and size of this created value, increased ESR participation will lead to commensurate increases in available storage capacity, all other things considered equal (i.e., resource costs). Assessing the value creation provide by use of the ESR participation models can offer insight into how the US energy storage capacity may change upon implementation of the models and identification of additional barriers to the development of greater storage resource capacity.

Electric storage resources are not unique in their ability to provide multiple types of services to the grid; generation resources have long provided energy, capacity and ancillary services. However, as the rate of renewable energy resources penetration has increased, so too has the appreciation of the uniquely broad range of services that electricity storage technologies can provide. In a meta-analysis of previous studies, Rocky Mountain Institute (RMI) provided a framework of 13 services, categorizing according to the stakeholders reaping the greatest benefits from a given service type (Fitzgerald, Mandel, Morris, & Touatl, 2015). These categories included RTO/ISO services, utility services and customer services. Several studies performed by the Brattle Group over the past few years identified a similar, but not identical, range of benefits that energy storage was capable of providing (Chang et al., 2015). In this case, the authors utilized a categorization based on parties through which the benefits would be measured, as summarized in Table 2-5.

**Table 2-5:** Electric Storage Resource Value Categorization
(Chang et al., 2015)

| Value Category | Category Description |
|---|---|
| Merchant Value | Net profits that a private investor could monetize by participating in wholesale markets |
| System-Wide/ Societal Benefits | Overall benefits of storage to the electric system as a whole, regardless of whether those benefits and costs accrue to the asset owner, retail customers, market participants or other entities |
| Customer Benefits | Benefits that accrue directly to electricity users |

Figure 2-2 provides a graphical comparison of these two models, delineating the value categorizations, associated value types common between the two categorization schemes, and value types unique to each categorization. Some differentiation between any energy storage valuation frameworks can be expected. As the electric grid continues to evolve, innovative uses of electric storage resources may be realized as new grid needs also materialize. In a related fashion, newer valuation studies may ignore previously assessed value types that have been demonstrated to be relatively insignificant. Also, some valuation studies may elect to emphasize or exclude specific electric storage benefits based on the intended study goals or the methodological difficulties introduced by specific value types.

Both categorization schemes can be used to assess the impact of the ESR participation models on the service value provided by storage resources and how that value is received by different grid participants and stakeholders. However, the value categorization utilized by the Brattle group provides a more intuitive structure for assessing the impact of new resource participation models to the electric system. First, the Brattle model's focus on merchant value (i.e., net profits obtainable by resource

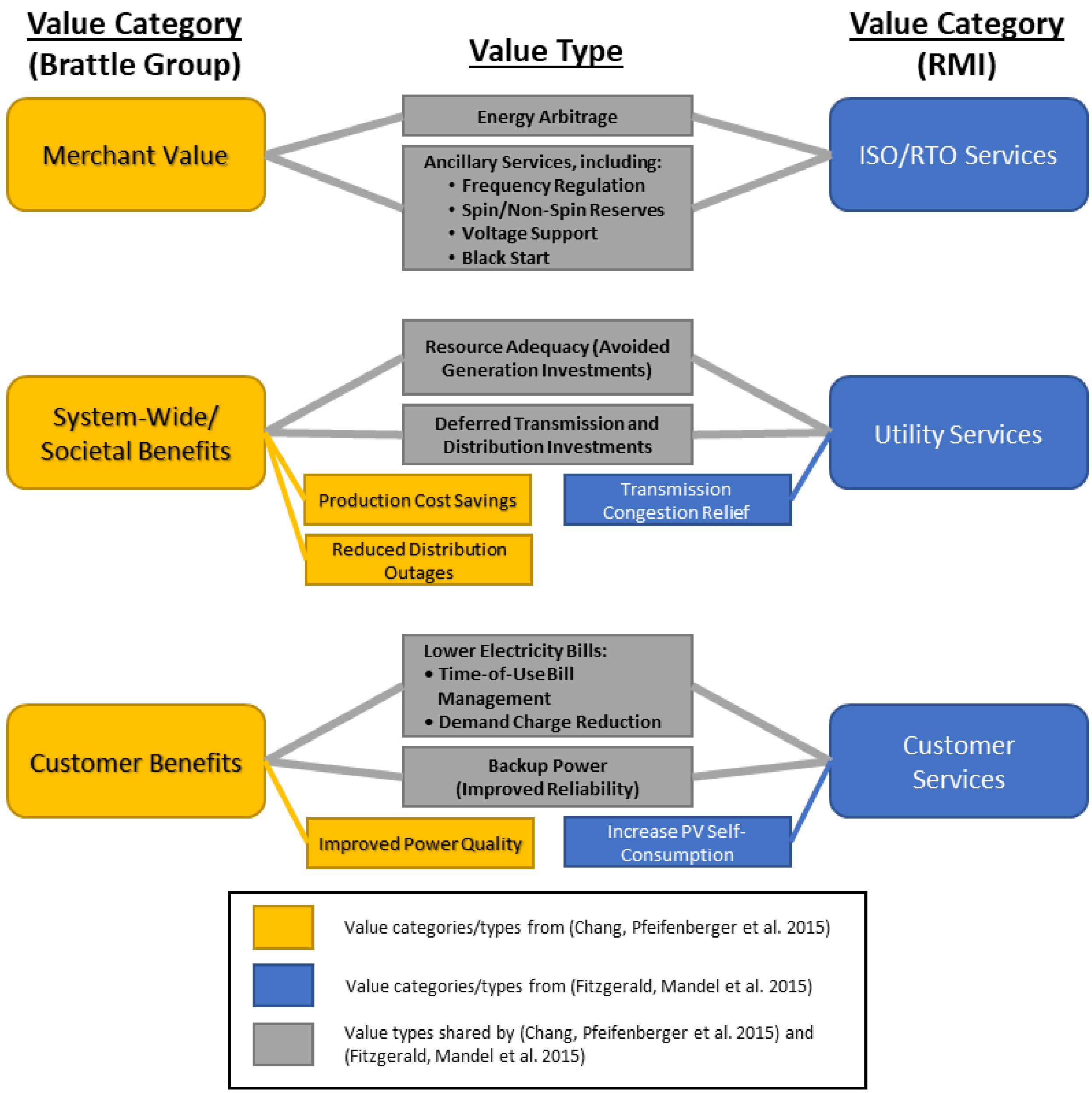


**Figure 2-2:** Two Models for Energy Storage Value Categorization (Chang et al., 2015; Fitzgerald et al., 2015)

owners) places a clear emphasis on the stakeholders directly responsible for developing and owning new electric storage resources, as well as the economic signals needed to achieve market equilibrium-levels of storage resources. RMI's alternate focus on RTO's/ISO's provides a more indirect assessment, given the absence of storage resource ownership by these organizations. Second, the Brattle group's broader definition of system-wide benefits is agnostic with respect to which stakeholder group should ultimately benefit from storage-derived values that are external to those enjoyed by resource owners; RMI's categorization implies exclusive enjoyment of these benefits by utilities. The treatment of customer benefits is comparable between the two categorization models. Elements of the ESR participation models have not yet been generally implemented, with the exception being for those RTO's/ISO's proposing to leverage existing wholesale market structures to meet the requirements in the Final Rule, as discussed further in Chapter 4. Thus, there have not been detailed quantitative studies undertaken to predict the impact of the ESR various participation models on either the realizable benefits at the merchant, system or customer levels, or the levels of storage capacity.

Nonetheless, studies have been performed that can illustrate useful insights about storage resource benefits relevant to the new ESR participation models. One study by the Brattle group investigated the value of distributed storage resources in the transmission region operated by the Electric Reliability Council of Texas (ERCOT) (Chang et al., 2015). The study attempted to predict the economic viability of varying storage deployment levels capable of meeting the peak load increases forecasted for

2020.  Scenarios ranging from 1000 – 8000 MW of deployed storage capacity were investigated.

The merchant value was observed to increase along with storage deployment level (Figure 2-3).  Despite these increasing total net profits for the storage resource owners, decreasing profit margins were forecast for higher storage deployment levels due primarily to saturation of the ancillary services market (Figure 2-4) by the added storage resources.  This source of declining merchant value with increased storage deployment may not be unique to the ERCOT region, but could also be experienced in regions where the sizes of ancillary services markets are significantly smaller than the respective energy markets[46].

In ERCOT region, merchant values alone were to forecasted to be sufficient to justify the costs of only the lowest levels of storage deployment considered.  Several cost estimates were utilized, reflecting: (1) expected and high battery cost with different fixed operations and maintenance costs, and (2) different discount rates (i.e., after-tax weighted-average cost of capital (ATWACC) to simulate financing available to larger utility owners (lower ATWACC) and smaller merchant owners (higher ATWACC).  As shown in Figure 2-3, with smaller merchants as the primary source of storage deployment, only 1000 MW of new storage capacity would be justified based on merchants recouping storage value from energy and ancillary service market net profits only, assuming they were able to achieve the expected battery and installation costs of

[46] As an example, ISO-NE's 2017 ancillary services costs ($128.3 million) were less than 3% of that from the energy markets ($4.5 billion) (ISO-NE, 2018a).

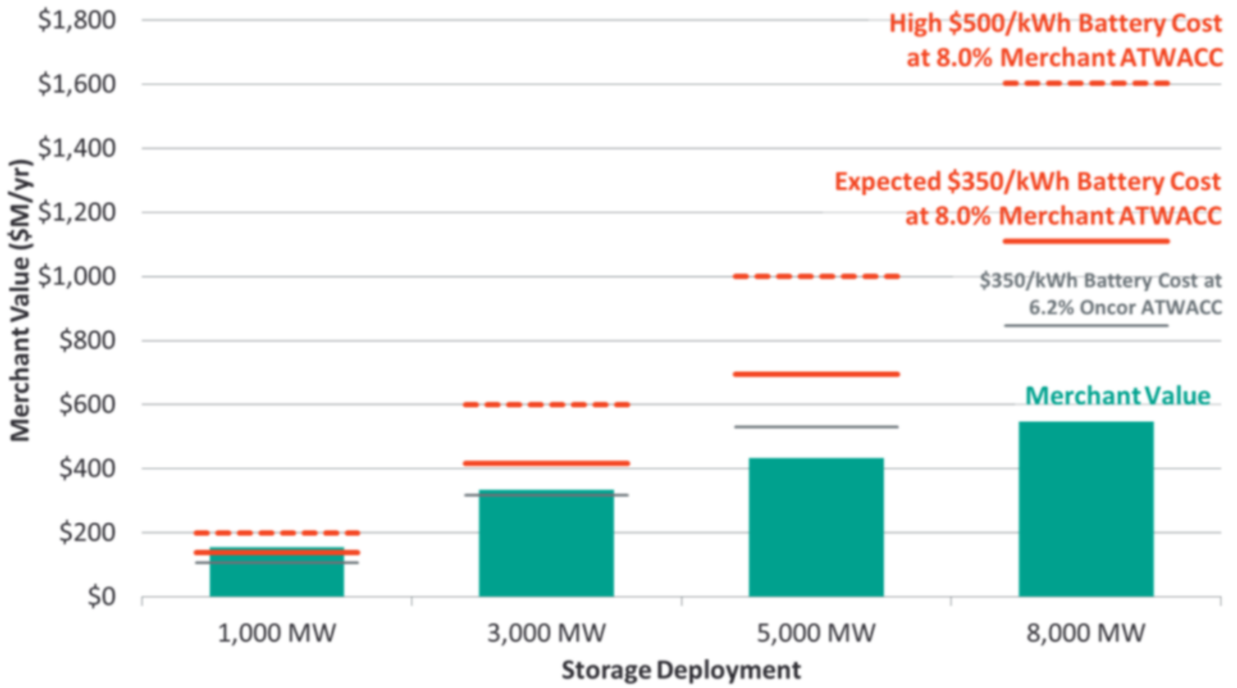


**Figure 2-3:** 2020 Forecasted Merchant Value and Storage Costs
(From Figure 17, (Chang et al., 2015))

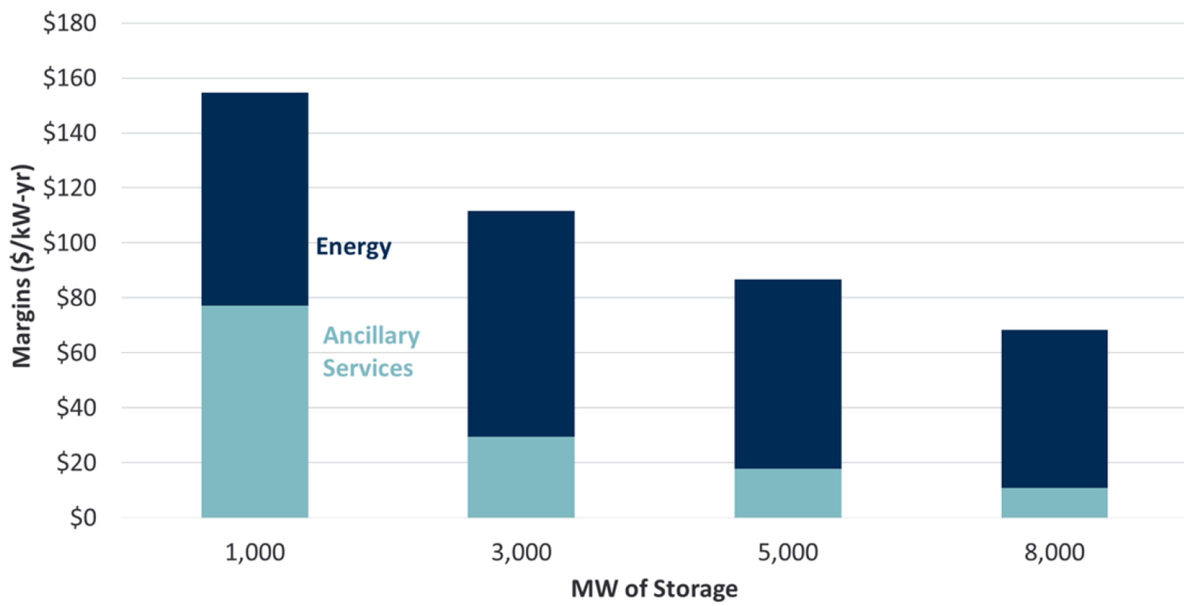


**Figure 2-4:** 2020 Annual Net Revenues for Storage
(From Figure 6, (Chang et al., 2015))

$350/kWh. Even with their lower financing costs, larger utility owners would still need to achieve the lower battery costs of $350/kWh in order for the somewhat higher deployment of 3000 MW to be financially viable.

Greater levels of storage deployment may become economically feasible if there is mechanism to provide at least some of the other value provided by the other two categories (system-wide and customer benefits). The Brattle group study of ERCOT region predicts that as much as 8000 MW of storage would be economically feasible based on currently expected 2020 battery costs (Figure 2-5). This assessment only considered large utilities with lower ATWACC in estimating prices, so inclusion of finite levels of smaller merchant ownership could be expected to again result in somewhat lower storage deployment. Regardless, one can still notice a pattern of declining marginal system-wide benefits with increasing storage deployment, similar to that observed when assessing merchant value. While there are no apparent decreases in any of the system-wide value types with increasing storage deployment, the growth of some components (e.g., avoided capacity investments) clearly do not keep up with the increased deployment costs.

With its focus on providing greater opportunities for storage resource participation, the ESR participation models required by the Final Rule will have a direct impact on merchant value. However, the participation model requirements lack any of the mechanisms needed to ensure that storage resource owners capture some of the system-wide benefits that could encourage the needed levels of investment for higher storage deployment levels. System-wide benefits are, by definition, more disperse and involve a greater number of stakeholders relative to merchant value. Therefore, it may

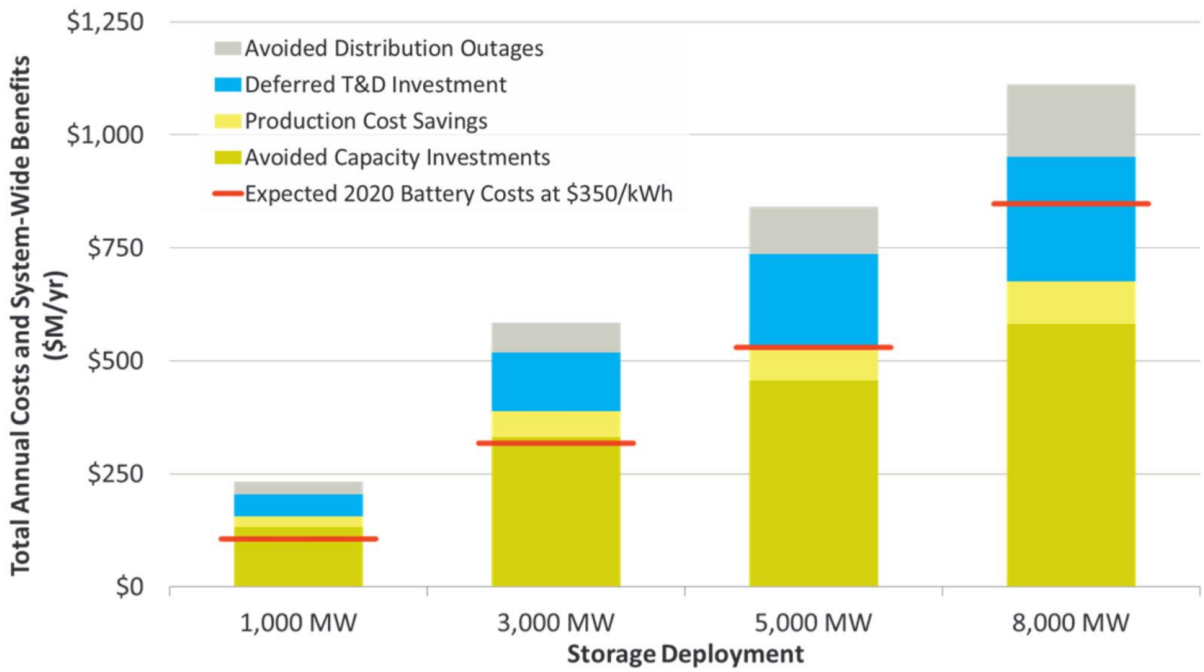


**Figure 2-5:** 2020 Annual Net Revenues for Storage
(From Figure 18, (Chang et al., 2015))

be a significantly greater challenge for FERC to expand upon its efforts, as started in this Final Rule, to further broaden energy storage participation in wholesale markets. The system-wide benefits may also involve planning for electric system components that are outside the scope of FERC's authority (e.g., generation and distribution planning). Such efforts will require close collaboration between the Commission and state-level regulatory entities.

## 2.6 Conclusions

The Final Rule issued in Order No. 841 by FERC outlines four principal requirements for a participation model for electric storage resources to be implemented by the various RTO's and ISO's. Resources that are qualified to meet the requirements of the associated new resource, the Electric Storage Resource, are eligible to provide all energy-related services in wholesale markets that they are technically capable of providing. The ESR participation models will be required to allow qualifying storage resources to be dispatched as a buyer and seller of energy market services. Resources utilizing the ESR participation will thus be eligible to set market clearing prices, regardless of whether submitted wholesale bids are for energy withdrawal, injection or both, in the case where the ESR is the marginal resource for a given market interval. To facilitate the ability to provide supply offers and demand bids in a fashion that does not impede wholesale market participation, the Final Rule provides a range of thirteen required bid parameters as part of the ESR participation model while providing RTO/ISO's with great flexibility on incorporation of these parameters into existing bidding systems. Additionally, the Final Rule proscribes that any storage resource be charged at the wholesale LMP when purchasing energy for storage that will later be reinjected to the grid for resale.

The Final Rule does indeed provide a framework to address issues related to storage resource participation in wholesale markets. However, as with any other regulatory effort, Order No. 841 can't reasonably be expected to address all outstanding issues on a topic as complex as energy storage, nor can it anticipate all future challenges associated with storage. Several issues were identified as out of scope of the Final Rule, but may become more critical as an increasing range of storage resources seek to participate in wholesale electric markets in the future: aggregated demand response participation, storage resource participation outside RTO/ISO territory, and careful coordination of transmission planning.

Finally, the current focus on using participation models to increase wholesale market competition is a mechanism by which FERC has significant experience using. However, this approach primarily addresses realization of merchant value, which may be insufficient to achieve optimal levels of storage resource deployment even as storage costs continue to decrease. The Commission will need to address how system-wide benefits are produced and consider mechanisms to leverage these benefits to provide more comprehensive market signals that energy storage owners need to aid in deploying economically-optimal storage capacity levels.

# Chapter 3 Legal Foundations and Jurisdictional Perspectives on ESR Regulation

## 3.1 Introduction

Just as with any other market structure, the US electricity market is not a static construct; even since restructuring away from the then-dominant vertically integrated utility models began in 1980's (Lazar, 2016), it has continued to evolve. Indeed, upon upcoming implementation of the tariff revisions defining the electric storage resource (ESR) participation models, Order No. 841 (FERC, 2018) itself will be one of the latest regulatory-driven changes occurring within US electricity markets.

The market structure, and the regulatory regime defining aspects of that structure, provides the mechanism (e.g., pricing signals) by which ESR service values are identified and the extent to which compensation is provided. In working towards creation of Order No. 841, the Federal Energy Regulatory Commission (FERC) has sought to create sustainable regulatory and market mechanisms needed to increase ESR participation beyond current levels.

Uncertainty around how an ESR can participate in US electricity markets may serve as an impediment to the realization of economically-optimal development, implementation and utilization of these resources. Since development and financing of ESR's involve making long-term decisions, rapid changes in this nascent regulatory regime could result in many ESR's becoming stranded assets. Additionally, regulatory uncertainty could conceivably lead to the long-term suppression of appetite for further investment in innovation of a resource that could greatly facilitate transition to a lower-carbon-emission national energy system.

An assessment of the ability of the requirements embodied in Order No. 841 to withstand judicial challenge can help inform the likelihood of the durability of the Order-driven participation models and the sustainability of the non-discriminatory environment for ESR's potential roles in the national electricity system. This assessment will include: (1) a brief overview of FERC's traditional jurisdiction over interstate wholesale electricity sales, (2) a summary of FERC's authorization and jurisdictional claims relevant to the Order, (3) discussion of vulnerabilities to judicial review by FERC's recent execution of that jurisdiction in Order No. 841 and (4) challenges arising from that jurisdictional execution.

### 3.2 FERC Jurisdiction over Interstate Wholesale Electricity Sales

An understanding of the derivation of FERC's currently exercised jurisdiction in electricity markets, along with the dual regulatory system established with the States, will illuminate subsequent discussions on the resilience that Order No. 841 may expect as the ISO's and RTO's begin implementation of their ESR participation models. Key to this understanding includes detailing Congress' driver for implementing regulation of electricity markets, the primary objectives of this regulation, and delineation of federal and state jurisdiction over wholesale electricity markets.

The need for Congressional action to regulate wholesale electricity sales became evident through the US Supreme Court's decision in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Elec. Co.* (*Public Util. Comm. V. Attleboro Co.*, 1927). The case resulted from the Public Utilities Commission of Rhode Island implementing price schedules for electricity purchases made by an out-of-state company (Attleboro Steam & Electric Company) from an in-state generator

(Narragansett Electric Lighting Company). The decision identified these sales as "national in character" (i.e., not local matters subject to jurisdiction of a single State). Accordingly, the Court indicated that only Congress has the power to enact regulations impacting such interstate commerce for electric power.

Congress ultimately did respond, enacting Part II (Regulation of Electric Utility Companies Engaged in Interstate Commerce) of the Federal Power Act (FPA) in 1935 (Federal Power Act, 1935). This addition to the FPA has since served as the overarching US statute governing regulation of electricity sales, transmission, distribution and generation. The integral statutory role assigned to FERC (and its predecessor group, the Federal Power Commission) is ensuring that all rates and charges for electricity sales within its jurisdiction, as well as rates and regulations impacting those sales, are "just, reasonable and not unduly discriminatory or preferential" (FERC, 2011a).

The FPA created a concurrent regulatory scheme where, not only are the federal jurisdictional bounds outlined, but explicit carve-outs for interdependent State jurisdiction not subject to preemption are provided (Dennis, Kelly, Nordhaus, & Smith, 2016; Lindh, 2013; Nordhaus, 2015). The specific aspects of federal jurisdiction captured in the FPA include electricity transmission and wholesale electricity sales when either occur as part of interstate commerce. The delineated State jurisdiction encompasses four areas: (1) electricity sales other than those within federal jurisdiction (i.e., sale at wholesale in interstate commerce), (2) generation or local distribution facilities, (3) facilities used for intra-state commerce, and (4) transmission facilities for electricity consumed wholly by the transmission facility owner (Federal Power Act, 1935).

The execution of this collaborative structure was greatly influenced by the US Supreme Court findings in *Federal Power Commission v. Southern California Edison Co.* (*Federal Power Commission v. Southern Cal. Edison*, 1964). In this case, the Court assessed whether the jurisdiction previously exercised by the CPUC over the rates charged to the City of Colton (CA) for energy generated at the Hoover Dam was preempted by the Dormant Commerce Clause of the US Constitution. The Court found that these interstate wholesale electricity sales were not exempt from federal jurisdiction, preempting the CPUC's jurisdiction. The decision went further by rejecting the need for case-by-case assessment of the federal jurisdictional scope under the FPA and that jurisdiction's impact on state regulation. This perspective was derived from the Congress' establishment of a "bright line easily ascertained" between state and federal jurisdiction as they relate to interstate wholesale electricity sales.

Taken together with the dual regulatory structure in Part II of the FPA and the *Federal Power Commission v. Southern California Edison Co.* decision, an operational understanding of state and federal jurisdictional authorization took shape for electricity sales. In the execution of this bright line, federal jurisdiction would preempt State statues and regulation in the case of interstate wholesale sales; the only exceptions would involve those clearly derived from the State carve-outs explicitly captured in the FPA or other applicable federal statutes (Lindh, 2013).

### 3.3 FERC's Authorization and Jurisdictional Claims in Order No. 841

As with other federal regulatory agencies, FERC exercises the authority conferred upon it by Congress, with the FPA serving as a key document defining the limits of that authority (*California Indep. Sys. Operator Corp. v. FERC*, 2004). To ensure its actions are lawful and within its statutorily-defined jurisdiction, FERC's regulations and actions are subject to judicial review (Administrative Procedure Act, 1946). Thus, a lack of care by FERC in documenting the statutory authority under which it is executing new regulations, such as with the present case in Order No. 841, could lead to the realization of significant regulatory risk and poor electricity market function.

Within the Order, there are two key matters discussed related to FERC's authority and its associated jurisdiction (FERC, 2018). First, FERC outlined a general consideration of whether it is authorized to enact regulations impacting resources that can be qualified as ESR's. Generally, the Commission viewed current market rules and available participation models as effectively introducing barriers to competition. As a result, the *status quo* for ESR participation in wholesale electricity markets was viewed as unjust and unreasonable; Order No. 841 is thus intended to serve as a needed mechanism to mitigate what FERC considers an unlawful state of a type defined by the FPA.

Central to FERC's assessment is the realization that technology used in the electricity system has not remained static, and as in the case of electricity storage, continued evolution can be expected. Regardless of specific technologies utilized, new resources are likely to have technical capabilities different from those envisioned when existing wholesale market rules were enacted by ISO's and RTO's (Gonzále, 2016). So, while an ESR may not be fully excluded from participating in wholesale markets, it may also not be able to provide all services that it is technically capable of due to limitations imposed by rules likely designed for traditional electrical system resources or specific technologies.  These barriers to full ESR participation, even if not intended when applicable market rules were designed, are now viewed as a source of restriction on market competition and a commensurate failure to ensure just and reasonable wholesale rates (FERC, 2018).

A second key jurisdictional matter in the Order arose as part of the Commission's determination on the definition of an ESR.  The original definition proposed in the Notice of Proposed Rulemaking (NOPR) characterized an ESR as "a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid regardless of where the resource is located on the electrical system" (FERC, 2016).  The Final Rule did not ultimately include any qualification of the ESR location, but provided clarification that system location does not establish applicability of the ESR definition.  Specifically, resources meeting the definition would not be limited to those interconnected to the interstate transmission system (i.e., the location of activities typically in scope of FERC jurisdiction); distribution-level and behind-the-meter (BTM) resources could also qualify as ESR's and come under federal jurisdiction (FERC, 2018) when seeking to participate in wholesale market activities.

This broad resource definition was indeed viewed positively by a number of commenters on the NOPR.  Perceived benefits of this approach include providing market access to energy exported by BTM storage resources (*Comments of the Energy Storage Association (Docket Nos. RM16-23-000; AD16-20-000; Order No. 841)*, 2017) and removal of barriers preventing BTM resources from providing both retail and wholesale services (*Comments of Advanced Microgrid Solutions, Inc. (Docket Nos. RM16-23-000; AD16-20-000; Order No. 841)*, 2017).

## 3.4 FERC Jurisdictional Execution and Order 841

### 3.4.1 Vulnerability to Judicial Review

If ESR's had capabilities that limited the resources to direct participation in only wholesale sales, or if they were only interconnected at the transmission level, FERC's claimed authority outlined for these resources would not be controversial. For example, PHES has provided energy storage services in the US since the 1930's (Yang & Jackson, 2011), and, as recently as the March, 2018, provided ~94% of all electricity storage capacity in the US (2018). When much of the existing PHES capacity was built in the US in the 1960's and 1970's, the value of this storage resource was largely based on economic comparisons to fossil fuel plants providing only utility-level energy and capacity (Denholm, Ela, Kirby, & Milligan, 2010). The grid interface (i.e., transmission level) and electricity market participation for these storage resources were thus comparable to that of conventional generators. Therefore, the traditional "bright line" between federal and state jurisdictional separation was generally suitable to provide clear, stable regulatory regimes under which long-term economic decisions on resource development and utilization could be made (Nordhaus, 2015).

The rapid change represented by the wider range of available storage technologies, recognition of and need for the wider range of services available from ESR's, and their attainment of critical levels of commercial maturity, prompted FERC to address barrier to ESR participation in wholesale markets (FERC, 2016). However, along with this diversity in services that ESR can provide, the grid and its applicable regulatory framework must now also contend with diversity in resource interconnection and market participation (Jacob, 2017). As new technologies and practices arise that can have direct impact on both the wholesale and retail levels, the bright line jurisdictional test may fall short; an engrained recognition of the potential interrelationship between federal and state regulatory actions will be needed.

Key among the challenges presented by the availability of these diverse services are questions regarding whether the FERC has inappropriately pre-empted state authority by establish regulations on distribution- and BTM-level electric system components. A number of commenters to the 2016 NOPR took issue with potential jurisdictional implications of the proposed resource definition. A consistent theme among the commenters was the extent to which the Order would impact established state and local-level jurisdiction. Possible impacted areas include provision of retail and distribution-level services (APPA/NRECA, 2017) and distribution system design (DTE Energy, 2017; MISO Transmission Owners, 2017)

Order No 841 is not the first instance where FERC has addressed wholesale market participation by sub-transmission-level resources. Recently, FERC issued Order Nos. 719 and 745, outlining demand response resource participation in wholesale markets (FERC, 2008b, 2011b). Of particular relevance to this discussion, various commenters to those orders questioned FERC's authority to set compensation for demand response resources in organized wholesale markets, declaring "that the issue of demand response compensation is fundamentally intertwined with retail rates, ratepayer issues and state jurisdictional concerns” (FERC, 2011b)[47].

Order No. 745 provided an explicit rejection of these challenges to the Commission’s claimed authority. The Commission had previously determined that demand response bids into wholesale markets have a direct impact on wholesale rates (FERC, 2008a)[48]. FERC thus claimed its authorization, citing its mandate provided by the FPA to ensure rates and charges for transmission or interstate wholesale sales are just and reasonable, especially when the respective activities are found to direct affect wholesale rates (FERC, 2011b)[49]

The Electric Power Supply Association, a trade association representing various large energy producers and generators, was among several petitioners that requested a judicial review of FERC’s claimed authority regarding direct response resources. Upon the ruling by the US District Court of Appeals for the District of Columbia to vacate the entirety of Order No. 745 (*Electric Power Supply Association v. Federal Energy Regulatory Commission*, 2015), FERC appealed the decision to the US Supreme Court. In the resulting ruling (*Federal Energy Regulatory Commission v. Electric Power Supply Association*, 2016), the US Supreme Court affirmed that FERC had operated within its authorized jurisdiction; Order No. 745 was indeed related to practices directly affecting wholesale rates. Additionally, FERC could exercise this jurisdiction without impinging State authorities outlined in the FPA since no attempts were made to regulate retail sales involving demand response.

[47] At Paragraph 103
[48] At Paragraph 47
[49] At Paragraph 112

Order No. 841 leverages the precedent set with demand response in Order Nos. 719 and 745 as well as the *Federal Energy Regulatory Commission v. Electric Power Supply Association* decision to reiterate the Commission's claim of exclusive jurisdiction over wholesale market participation, even for resources connected at the sub-transmission level (FERC, 2018)[50]. However, FERC's efforts on ESR's excluded one aspect that was part of the Orders on demand response; no allowance is made for relevant State-level regulatory bodies to prohibit ESR owners from making wholesale markets bids. While generally discussed in the context of aggregated storage resource participation, commenters noted the value afforded by certain rule features (e.g., inclusion of a State-level opt out for allowing distribution-level of BTM resources from participating in wholesale markets) to the maintenance of State-level jurisdiction (DTE Energy, 2017; MISO Transmission Owners, 2017).

The absence of such opt-outs in the Order may reinforce concerns regarding over-expansive jurisdictional claims by FERC at the expense of those reserved for States by the FPA. An initial avenue for challenges could originate from the *Federal Energy Regulatory Commission v. Electric Power Supply Association* decision the Order No. 841 leverages as precedent. Specifically, the decision cites Order No. 745's allowance for "any State regulator to prohibit its consumers from making demand response bids in the wholesale market" as a demonstration of "FERC's notable solicitude toward the States" (*Federal Energy Regulatory Commission v. Electric Power Supply Association et al.*, 2016). It is this recognition by FERC, derived from the interrelated nature of wholesale and retail markets especially relevant for sub-transmission-level resources,

[50] At Paragraph 35

that served as the "finishing blow" to EPSA's claims of federal intrusion on State-level jurisdiction.

The Final Rule in Order No. 841 does recognize the variety of roles that states play in the implementation of electric storage resources, including design, operation and reliability of the distribution system, in addition to regulation of retail services (FERC, 2018)[51]. It also states the intention to not affect the responsibilities of distribution utilities, especially with respect to electric storage resource. The need for such allowances may become more pressing as FERC works further on the aggregated ESR docket.

### 3.4.2 Challenges Arising from FERC's Jurisdictional Execution

The nature of the electric grid and its associated components and practices will continue to evolve, presenting new jurisdictional challenges for FERC, state-level regulators, grid service suppliers and customers. Electric storage and demand response are just two examples where the classical "bright line" that provided a clear interface between federal and state regulatory jurisdiction is no longer so obvious now that specific grid components can play significant roles in both wholesale and retail markets. In both cases, the Commission staked out a seemingly broader implementation of its authorized jurisdiction at the expense the states' jurisdiction by focusing on the direct impact to interstate wholesale sales by ESR and demand response participation. The validity of the Commission's approach to preempting State authority over all interstate wholesale sales was upheld for demand response with the *Federal Energy Regulatory*

[51] At Paragraph 36

*Commission v. Electric Power Supply Association* ruling. To date, no such cases have been brought involving Order No. 841 and energy storage; it may be too early to tell if or how Order No. 841 will be challenged for possible unlawful preemption of State powers authorized under Part II of the FPA.

This increasing deference to federal jurisdiction at the expense of the states' authority, even if it survives future judicial challenge, does not come without consequences. For example, in its Orders on electric storage and demand response wholesale market participation, the Commission has continued to recognize earlier participation by such resources in specific states as a precursor to taking broader, national-level actions (FERC, 2018)[52], (FERC, 2008b)[53]. The states can thus effectively provide environments capable of delivering earlier introduction of technological and market innovations. It is unlikely that FERC could ever develop the detailed understanding of local-level grid aspects and stakeholder impacts, as well as gather the necessary resources, to match what the sum of the nation's individual states could apply to such challenges. The end result of this jurisdictional approach could inhibit the development and maturing of technological innovations that FERC is seeking to attain just and reasonable electricity rates through increased wholesale market competition.

It should be noted that while FERC has taken a more exclusive interpretation of its jurisdiction when it perceives an action directly impacting interstate wholesale electricity prices, the Commission still acknowledges the "vital role of the states with respect to the development and operation of electric storage resources." (FERC, 2018)[54]. This

[52] At Paragraph 11
[53] At Paragraph 18
[54] At Paragraph 36

perspective, voiced in establishing the requirements for the ESR participation model, mirrors the fundamentally intertwined nature of demand response jurisdictional issues previously expressed by the Commission (FERC, 2011b)[55]. Such recognition may be a sign of FERC's understanding the value of continued cooperative actions with its State-level counterparts. In the absence of focused actions undertaken to exploit benefits available from deeper, cooperative relationships with State regulatory bodies, it isn't clear how successful or timely FERC will be in addressing this challenge[56].

Additionally, development of market design and practices applied on the national, or even the regional level managed by the individual RTO/ISO's, without being informed of relevant needs at the state and local level risks can introduce unintended reliability concerns to the electric system. For example, RTO/ISO's have a mandated role in long-term transmission planning, whereas distribution planning is left to state and local regulatory bodies. As described by De Martini et. al., (distribution and transmission system planning are foreseen to require an integrated approach for electric systems seeking high levels of distributed energy resources, including energy storage, while still maintaining acceptable reliability levels (De Martini & Kristov, 2015). Thus, the transmission and distribution planning required to meet many of the state-level renewable energy policy goals, in addition to the concomitant increases in wholesale

[55] At Paragraph 103

[56] FERC Order 719, footnote 79 mentions efforts between National Association of Regulatory Commissioners and the Commission to "outline options to coordinate retail and wholesale regulatory policies in order to stimulate demand response by reducing or eliminating jurisdictional barriers" (FERC, 2008b). Further research into the scope and impact of these efforts may better illuminate the value of FERC's efforts to date to proactively address multi-jurisdictional issues faced by distributed energy resources (including ESR's and demand response).

electric market competition sought by FERC, will likely require more than just an ever-expanding deference to federal jurisdiction.

Finally, any evolving regulatory regime will likely cause some level of uncertainty in stakeholders wishing to initiate or further expand provision of novel services, including those provided by ESR's. In the face of changing regulatory regimes, organizations must not simply contend with the ability of their current business model to create and capture value in earlier market conditions. A business model's ability "to remain feasible and viable in a changing business environment" (Haaker, Bouwman, Janssen, & De Reuver, 2017) becomes just as critical as understanding how the model fundamentally allows it to create and capture value (Bouwman H., 2008).

The electricity sector, like other infrastructure sectors, are capital intensive, utilize long-lived physical assets and are subject to significant regulation (Markard, 2011). These features make the sector vulnerable to developing substantial levels of stranded assets if the underlying business models are not sufficiently robust. The importance that regulations play in determining electricity sector business model viability has begun receiving greater attention, typically as part of studies investigating sector disruptions such as renewable energy transitions and introduction of market competition (Leisen, Steffen, & Weber, 2019). Indeed, the nature of regulations and associated institutions are viewed as playing a key role in both renewable energy technology innovation (Markard, 2011) and deciding the degree of future renewable infrastructure centralization (Schmid, Knopf, & Pechan, 2016).

A policy process effect, originating from uncertainty in initial business model viability and long-term resilience in the face of uncertainty in the speed and probability of regulatory regime change, has been identified as a source of investments gaps (Garnier & Madlener, 2016). For ESR's, one such policy process impact can result from judicial review and subsequent rollback of novel aspects of the regulatory structure and participation model implementation created by Order No. 841. The risk of such an occurrence has the potential to remove mid- or long-term market participation by a resource class that is still in an early innovative phase. Mitigation of such risks could involve a number of undesirable outcomes: (1) chilling further investments in innovation that could reduce the cost and increase the capability of future types of ESR's, (2) lowering levels of investment to implement mature ESR technologies for market participation (avoiding the risk of owning newly-stranded assets), and (3) need for additional incentives to maintain desired investment levels.

### 3.5 Conclusions

The unidirectional design of the early US electric grid provided for a reasonably clear delineation between electricity producers, suppliers and customers. This demarcation allowed for a clear differentiation between parties to wholesale (inter- and intra-state) and retail electricity sales, and the effectuation of the dual federal and state jurisdictional structure, as authorized by Part II of the FPA, along this "bright line".

ESR's, and other distributed energy resources, now present a landscape where market participants can simultaneously provide wholesale and retail services. At the same time, this technology is enabling generation assets to be located at all interconnection-levels, including behind the meters of traditional retail customers. Time and technology have thus served to blur the line (Nordhaus, 2015) that had provided a relatively clear understanding by electric system stakeholders of a key aspect of the federal and state regulatory structure.

Acknowledging this evolution, FERC outlined two elements in Order No. 841 to justify its continued ability to regulate interstate wholesale sales as embodied in issuance of the Final Rule. First, the FPA clearly provided authorization to the Commission to remedy the any unjust and unreasonable interstate wholesale electricity rates, including those resulting from current market rules and participation models not reflecting an ESR's full capabilities. Second, the FPA provided no qualification to the Commission's authority regarding the nature of the market participants or the interconnection of relevant electrical system components, as long as they were directly impacting interstate wholesale electricity sales.

While aligning with one perspective of FERC's long-established jurisdictional authorization, the justifications leveraged in Order No. 841 do not come without vulnerabilities to judicial challenge. Concerns that Order No. 841 may lead to eventual unlawful pre-emption of state authority by FERC in establishing regulations on distribution- and BTM-level electric system components were voiced in stakeholder comments on the Final Rule. A similar version of the jurisdictional construct outlined in Order No. 841 was upheld for demand response resources with the *Federal Energy Regulatory Commission v. Electric Power Supply Association* ruling. However, a lack of deference to State regulatory authority to allowing prohibition of ESR owners from making wholesale market bids, unlike that provided for demand response participation models, may reinforce concerns of regulatory overreach by the Commission.

FERC's current jurisdictional approach to distributed energy resources presents opportunities to drive unintended adverse effects on the US electric system. First, excessive minimization of the roles of state regulatory agencies can stifle the innovative incubation environments provided at the state level that can efficiently drive the technological innovations sought by FERC to enable increased interstate wholesale electric market competition. Second, wholesale market design developed in a vacuum on the federal/regional level may introduce unintended reliability risks to the electric system arising from market and grid performance issues arising at the state and local levels. Finally, any rollback in the interstate wholesale electric market processes due to regulatory overreach by FERC will create uncertainty in the existing regulatory regime experienced by ESR's. This uncertainty will drive unwanted opportunities for investment gaps in the development and commissioning of ESR's and other distributed energy resources. Continued, active engagement between FERC and its State-level counterparts will become increasingly important to avoid these undesirable outcomes, especially as the types of mature distributed energy resources increases and their use in wholesale electric markets accelerates.

# Chapter 4 Assessment of Proposed RTO/ISO Market and Tariff Revisions

## 4.1 Order No. 841 Compliance Plan Filings

In alignment with the action timelines required by Order No. 841, the six ISO/RTO's filed their proposed Tariff revisions on December 3, 2018. In addition to the red-lined Tariff versions, the filings also required a presentation of the justification as to how the Tariff updates would comply with the Order No. 841 Final Rule requirements for the ESR participation model and the prices paid for ESR charging used for subsequent wholesale transaction. The relevant docket under which the respective Tariff proposals were filed are presented in Table 4-1.

**Table 4-1:** FERC Dockets: ISO/RTO Order No. 841 Compliance Plan Filings

| ISO/RTO | FERC Docket[57] |
|---|---|
| California ISO (CAISO) | ER19-468 |
| ISO New England (ISO-NE) | ER19-470 |
| Midwest ISO (MISO) | ER19-465 |
| New York ISO (NYISO) | ER19-467 |
| PJM Interconnection | ER19-469 (Markets and Operations Proposal)<br>ER19-462 (Accounting Proposal) |
| Southwest Power Pool (SPP) | ER19-460 |

The Energy Reliability Council of Texas (ERCOT) is not subject to the requirements to submit Tariff updates in compliance with Order No. 841 because the operation of

[57] FERC dockets can be accessed at https://elibrary.ferc.gov/idmws/docket_search.asp

ERCOT's wholly intrastate transmission system is outside the jurisdiction established for FERC under the Federal Power Act. Despite the absence of such an obligation, ERCOT is maintaining awareness of the activities that other ISO/RTO's have undertaken in order to "help inform its own future processes related to the integration of electric storage resources" (ERCOT, 2019b).

Line-by-line analysis of the red-lined versions of the proposed tariff revisions from the six in-scope RTO/ISO/s would be an exhaustive method to outlining the approaches proposed for establishing the energy storage-specific participation models. Yet this approach risks missing the forest through the trees. Therefore, this chapter will attempt to tabulate and discuss key themes and approaches taken by the RTO/ISO's within their proposed participation models. Additionally, a brief overview of the compliance deficiency letters sent by FERC on April 1, 2019 to each of the RTO/ISO's will be provided as an assessment of the Commission's outstanding compliance concerns with the proposed compliance plans.

## 4.2 Proposed Participation Models

This section will provide a tabulation of the participation models proposed by the RTO/ISO's, with a brief discussion on the different paths taken to develop these models. This overview is followed by a presentation of select elements of the participation models and an explanation of the use of the resource types in relation to participation models. Finally, specific details of the role of the proposed participation models in the RTO/ISO unit commitment and dispatch process are discussed.

Overview of Proposed Participation Models

In line with the flexibility provided by Order No. 841 to comply with the requirements to establish ESR participation models, the compliance plans from the RTO/ISO's each have unique features designed to best fit with existing market structure and supporting infrastructure elements (e.g., market optimization software). As shown in Table 4-2, each RTO/ISO has provided one or more participation model under which storage resources can bid for or offer to provide service through wholesale markets.

The effort a given RTO/ISO had invested, prior to Order No. 841 becoming effective, towards developing market structures enable storage resource participation, had a large impact on the proposed ESR participation models. For example, CAISO had worked for several years to develop and implement the Non-Generator Resource (NGR) participation model (CAISO, 2018). CAISO's participation plan therefore has attempted to justify compliance of the NGR model with the Order No. 841 requirements. Conversely, SPP had not previously needed to support methods for storage resource participation beyond that needed for existing PHES resources (FERC, 2019c). As such, SPP added new tariff elements that were often taken directly from the Order itself.

Other RTO/ISO's had previously allowed participation by newer storage technologies, but didn't provide for the full participation called for in the Final Rule. In such cases, the compliance plans adapted existing tariff elements to fill the gaps necessary to meet the Final Rule requirements. PJM modified an existing Energy Storage Resource model to permit for energy withdrawals (FERC, 2019b). In a similar fashion, ISO-NE made significant progress in vetting a platform enabling wholesale market participation by

**Table 4-2:** Proposed Participation Model and Resource Types

| ISO/RTO | Participation Model | Model Details | Available Resource Types |
|---|---|---|---|
| CAISO | Non-Generator Resource (NGR) | **Primary participation model for common storage technologies**<br>• Operates as either Generation or Load<br>• Dispatchable to any operating level, seamlessly over entire capacity range<br>• Constrained by a MWh limit to generate or consume Energy<br>• Can elect to use Regulation Energy Management for more efficient capacity bids into Day-Ahead (DA) regulation markets | |
| | Pumped-Storage Hydro Units | • Used for hydroelectric dams capable of producing electricity and pumping water for later energy production<br>• Operates as either Generation or Load | • Generating Unit (injection)<br>• Participating Load (withdrawal) |
| | Demand Response Resource | • Provides dispatchable demand (withdrawal)<br>• Generally used by Behind-the-Meter (BTM) retail customers and aggregated resources | • Proxy Demand Resources (traditional demand response)<br>• Reliability Demand Resources (dispatched near or at system emergency) |
| ISO-NE | Energy Storage Facility – Continuous | • Transitions seamlessly (< 10 minutes) between charging and discharging<br>• Dispatchable to any operating level over entire capacity range | • Generator Asset (GA) (injection)<br>• Dispatchable Asset Related Demand (DARD) (withdrawal)<br>• Alternative Technology Regulation Resource (ATRR) (Regulation) |
| | Energy Storage Facility – Binary | Extends PHES storage treatment to other storage technologies<br>• Can't instantly (<10 minutes) switch from charging to discharging | • GA (injection and regulation)<br>• DARD (withdrawal) *available starting in 2024* |

**Table 4-2:** Proposed Participation Model and Resource Types (cont'd)

| ISO/RTO | Participation Model | Model Details | Available Resource Types |
|---|---|---|---|
| MISO | Electric Storage Resource | • Includes all technologies and/or storage mediums<br>• Must be physically located within MISO Balancing Authority Area | |
| NYISO | Energy Storage Resource | • Dispatchable to any operating level, seamlessly over entire capacity range<br>• Continuous bid curves across full operating range<br>• Dispatch-only resources (DA and Real Time (RT) Energy Markets only)<br>• Does not include BTM Net Generation Resources<br>• Energy injection and withdrawal must occur at the same location<br>• Capable of sustained injection at 0.1 MW for at least 1 hour | • Supplier (provides capacity, demand reductions, energy or ancillary services)<br>• Withdrawal-Eligible Generator |
| | Generator | • Injection-only resource | |
| | Energy Limited Resources | • Not capable of continuous operation on a daily basis<br>• Must be capable of operating for at least 4 consecutive hours each day<br>• Accommodates "infeasible" operating range around 0 MW | • Supplier (provides capacity, demand reductions, energy or ancillary services)<br>• Withdrawal-Eligible Generator |
| | Limited Energy Storage Resource | • Regulation Service provision only<br>• Not capable of sustaining continuous operation at maximum Energy withdrawal or injection limits for at least 1 hour | |
| | Demand Response Programs | • Capable of being dispatched to curtail Load | • Demand Side Resource |

**Table 4-2:** Proposed Participation Model and Resource Types (cont'd)

| ISO/RTO | Participation Model | • Model Details | Available Resource Types |
|---|---|---|---|
| PJM | Energy Storage Resource | • Expands role to also include Market Buyer (withdrawal)<br>• Emphasizes real time dispatchability and price setting; no optimization in DA Market<br>• Participates in Energy, Capacity and/or Ancillary Services Markets<br>• Participation model selection to occur on annual basis | |
| | Capacity Storage Resource | • Expands role to also include Market Buyer (withdrawal)<br>• Emphasizes real time dispatchability and price setting; no optimization in DA Market<br>• Participates in the Reliability Pricing Model or otherwise treated as capacity<br>• Participation model selection to occur on annual basis | |
| | Pumped Hydro Storage Resource | • Developed for large pumped hydro storage sources (min. 500 MW) that can be turn on/off quickly<br>• Utilizes an optimizer to establish DA Energy Market schedules<br>• Not scalable to small, fast-responding systems | |
| SPP | Energy Storage Resource | • Introduction of dispatchable Energy withdrawal to SPP's Markets<br>• Excludes resources physically incapable of or contractually barred from injecting Energy to the Transmission System<br>• Dispatchable to any operating level, seamlessly over entire capacity range<br>• Resources with discontinuous Energy Offer Curves across 0 MW need to choose to offer either supply or demand | • Market Storage Resource |

battery storage technologies. A plan based on these earlier efforts was filed with the Commission on October 10, 2018 (ISO-NE, 2018b), but was later modified to address known compliance gaps with the Final Rule Requirements (ISO-NE, 2018c).

Participation Models Elements and Resource Types

Some RTO/ISO's offer multiple participation models available to storage resources, with the resource owner provided the discretion to select a given model as required per the Final Rule. PJM and CAISO provide models specifically geared toward PHES resources, while ISO-NE offers a Binary Storage Resource model originally designed for PHES resources that was recently broadened to allow use by any resource that can't instantaneously switch (i.e., in less than 10 minutes) between charging and discharging. PJM provides separate models for storage resource seeking to provide either general services (e.g., energy, capacity and ancillary services) or exclusively capacity services; model election can be updated on an annual basis by the resource owner. NYISO instead has proposed participation models based on the ability to provide daily continuous operation.

While compliance with the Final Rule requirements is ensures the availability of at least one compliant participation model, there is no requirement that all participation models available to storage resources are compliant. Thus, there are still participation models available to storage resources, in cases where RTO/ISO's offer multiple options, that will not comply with the Final Rule requirements. An obvious example are the demand response models offered by NYISO and CAISO, which can be utilized by storage resources, but only allow resources to be dispatched for energy withdrawal.

Finally, some RTO/ISO additionally use the concept of a resource type, or alternatively, a registration type, along with participation models. As indicated in Chapter 2, FERC refers to participation models as the tariff provisions applicable to specific resource types. Resource types, however, is not a term explicitly defined in the compliance plans or tariffs, but is used here to refer to the classification of an asset under which it will be registered to participate in a given market or provide specific services. Table 4-2 indicates the various resource types available for specific participation models provided for storage resources by the various RTO/ISO's. Resource type registration can be applied to specific participation models, as shown in Figure 4-1 for the SPP Market Storage Resource, which only applies to the Energy Storage Resource participation model.

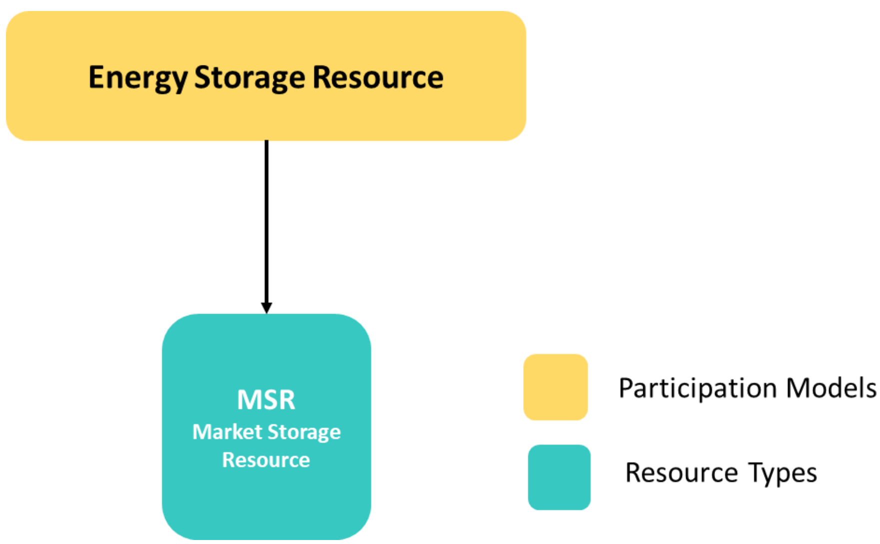


**Figure 4-1:** SPP Energy Storage Participation Model and Resource Type

More complex relationships can exist between participation models and resources, such as that shown in Figure 4-2 for the ISO-NE Energy Storage Facility-related resource types. Assets registered as a Continuous Storage Facility (CSF) must be registered for

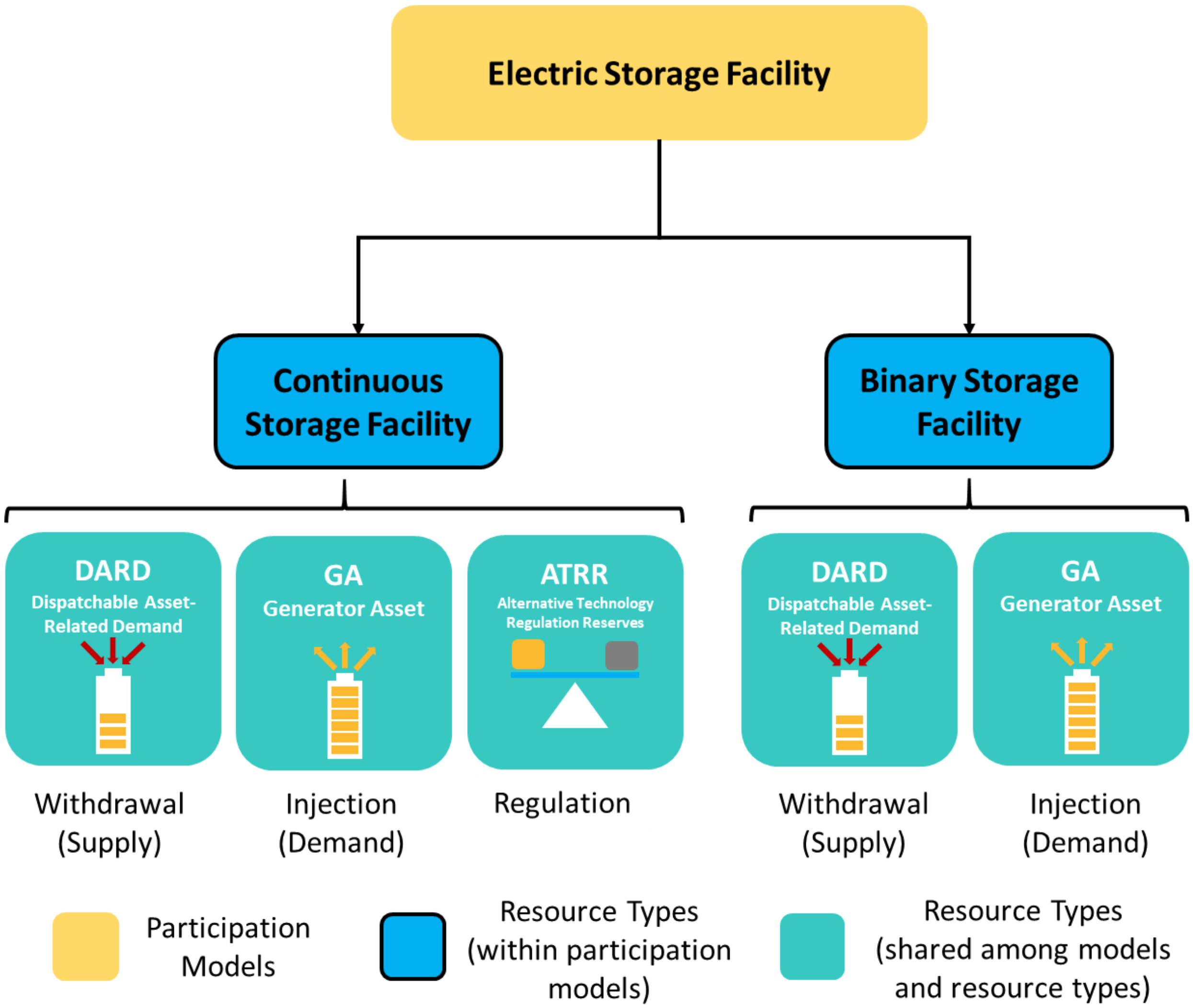


**Figure 4-2:** ISO-NE Energy Storage Participation Models and Resource Types[58]

three additional resource types: (1) a Dispatchable Asset Related Demand (DARD) to provide energy withdrawals, (2) and Generator Asset (GA) to provide energy injections, and an Alternate Technology Regulation Resource (ATRR) in order to provide regulation services. However, the DARD, GA and ATRR resource types are not limited to the registration of Continuous Storage Facilities; Figure 4-2 also displays the

[58] Portions of Figure 4-2 were adapted from (Peet, Asselin, & Pant, 2019)

resource types for which a Binary Storage Facility would need to be registered (i.e., DARD and GA).

<u>Unit Commitment and Dispatch – Storage Resource Limitations</u>

The proposed participation models take a variety of approaches to unit commitment and dispatch. These approaches provide insights into the capabilities of a given RTO/ISO's market processes and infrastructure, and how the current storage technology operation capabilities are perceived. In the case the RTO/ISO day-ahead and real-time markets, the following generic definitions can be utilized for unit commitment and dispatch:

**<u>Unit Commitment</u>**: *The process of creating a schedule of resources to be in a specific operating state (e.g., "On" or "Off") for specific market intervals, utilizing participant-provided bid/offer data and resource operating constraints*

**<u>Dispatch</u>**: *Use of resources assigned via a previous unit commitment process, or those currently available to be utilized, to provide specific grid services in a specific market interval*

A number of RTO/ISO's place restrictions on the unit commitment process for resources using ESR participation models. One common restriction is the required use of a continuous bid curve covering the quantities of energy to be injected or withdrawn for a given price. Continuous bid curves across the whole injection/withdrawal range require the absence of operational discontinuities around 0 MW than can result from finite minimum charging/discharging limits and times, or non-instantaneous ramp rates. Therefore, a requirement for continuous bid curves implies that storage resources must serve as dispatch-only resources or, from an equivalent operational perspective, have no technical constraints preventing dispatch anywhere along the provided bid curve range for any market interval.

NYISO's Energy Storage Resource and ISO-NE's CSF both explicitly require continuous bid curves, but their respective participation models approach the lack of commitment availability somewhat differently. NYISO's Energy Storage Resource is explicitly defined as a dispatch-only resource (NYISO, 2018b). NYISO has indicated that the need for requiring continuous bid curves originated specifically from limitations with the existing unit commitment software; timely solutions for the DA and RT-Market unit commitments became infeasible with inclusion of as little as eight such non-continuous resources. NYISO does acknowledge that such limitations are currently acceptable for current storage technologies (e.g., battery storage) that would potentially be used within its territory, but may not provide for the technologically-agnostic participation required by the Final Rule. As discussed below in Section 4-4, this gap has been noted by the Commission; it is not yet known how NYISO will ultimately address this gap in the near term.

In comparison, ISO-NE does include CSF's in its unit commitment process. However, various bid parameters essential for the commitment process must be set to 0 (e.g., Economic Minimum Limit, Minimum Run Time, Start-up Fees, etc.), indicating that such resources can be dispatched during any interval in which it has submitted a bid curve. It should be noted that ISO-NE does provide some allowance for storage resources with operational limit preventing instantaneous switching between charging and discharging through the ability to utilize the alternate Binary Storage Facility participation model. The services that a Binary Storage Facility is permitted to provide is commensurately limited, though; the longer switch time precludes provision of regulatory reserves and the mechanism to register such facilities to provide energy withdrawals is not planned to be available until 2024.

MISO and PJM take a similar approach to unit and commitment and dispatch as ISO-NE, leveraging details of submitted bid curves. These RTO/ISO's employ an additional designation, a resource's commitment status, to inform the commitment process of how to schedule the respective storage resources. Both regions utilize a range of commitment status specifications (e.g., Continuous, Charge, Discharge, etc.) providing general information on how the RTO/ISO can commit the associated storage resource. Electric Storage Resources in MISO markets and Energy Storage Resources in PJM markets do have the option to offer both energy injection and withdrawal in a given interval when designating a Continuous commitment status (FERC, 2019b; MISO, 2018). Such storage resources must provide a continuous bid curve over its entire submitted operating range, or equivalently, provide no start-up or ramp rate limitations. As discussed above, requirements for such continuous bid curves are comparable to a "dispatch-only" operation state, even when nominally included the storage resource in the unit commitment process. Storage resource with relevant operating limitations can still submit bid curves for a given interval, but instead must submit offers for either energy injection or withdrawal in a single market interval, and designating a commitment status of either "Charge" or "Discharge"[59].

---

[59] MISO has additional Commitment Status designations including those related to charging and discharging under emergency conditions. However, the analysis focuses primarily on normal grid operating conditions.

One interesting element of the MISO and PJM commitment process involves some of the time-related bidding parameters (e.g., Minimum/Maximum Run Time, etc.) that are critical operational limitations of conventional resources bidding into the commitment process. Both MISO and PJM allow storage resources with a Continuous commitment mode to submit values for such parameters, but parameter submission is optional; submitted values are either not used in the unit commitment process (MISO) or storage resources are expected to manage their effective commitment status through other means (PJM). While MISO and PJM include justifications in their respective compliance plans as to why these approaches do comply with the requirements of the Order, especially regarding optional submission of specific bidding parameters, FERC has not initially accepted such proposals with submission of further explanation (see Section 4-4 below).

SPP's approach to unit commitment and dispatch is a simpler version of that used by MISO and PJM; a Market Storage Resources (MSR) can only provide energy injection and withdrawal bids if the associated bid reflects an ability to be continually dispatchable across its entire operation range, including 0 MW, for a given market interval. Otherwise, an MSR would need to choose to provide offers for either energy injection of withdrawal for specific market intervals.

CAISO's unit commitment and dispatch process for NGR's appears to provide the greatest amount of flexibility for a variety of storage operational characteristics. A single bid curve covering a resource's operational range must be submitted. While the compliance filing does not contain any requirements about allowances for discontinuities in the bid curve, it clearly states that some unit-commitment-related bidding parameters (see below) can be submitted for a given resource, typically as master file parameters, with the parameter values being respected during as part of the unit commitment process and dispatch in the Day-Ahead and Real Time markets. Allowance for and respect of non-zero values for Minimum Load or non-instantaneous Ramp Rates are thus a mechanism for allowing non-continuous storage resources (i.e., dispatch-only assets incapable of instantaneous transition from energy injection to withdrawal across its entire operational range) to participate in the unit commitment process and dispatch utilizing the NGR participation model.

### 4.3 Overview of Proposed Bid Parameters

While details of the participation models and associated resource types are important elements describing how storage resources will interact with the respective RTO/ISO wholesale markets, the significance of the bidding parameters adopted for the participation models can't be understated. Bidding parameters provide clear, quantitative boundaries to storage resource operational capabilities and operating limits. These values are utilized by the RTO/ISO's to ensure that feasible dispatch schedules are calculated in both day-ahead and real-time markets and for provision of a variety of ancillary services.

The following section provides a tabulation of the bidding parameters proposed by the RTO/ISO's in their compliance plans, including their relation to a corresponding Final Rule bidding parameter, and where needed for clarity, RTO-specific definition elements and parameter utilization details. Table 4-3 provides a guide to the subsequent tables of proposed bidding parameters, which are delineated by the same parameter categorization used in Chapter 2. RTO/ISO's were allowed to propose bidding parameters beyond those required in the Final Rule, as long their use does not introduce barriers to storage resource providing services for which they are physically and operational capable of. These additional parameters are included in Table 4-7.

**Table 4-3:** Overview of Tables Summarizing RTO/ISO-Specific Bidding Parameter Proposals

| Bid Parameter Proposal Summary | Bidding Parameter Category | Order No. 841 Bidding Parameter Nomenclature |
|---|---|---|
| Table 4-4 | Charge States and Rates | • State of Charge<br>• Maximum State of Charge<br>• Minimum State of Charge<br>• Maximum Charge Limit<br>• Maximum Discharge Limit |
| Table 4-5 | Operational Durations | • Minimum Charge Time<br>• Maximum Charge Time<br>• Minimum Run Time<br>• Maximum Run Time |
| Table 4-6 | Improved Service Procurement Efficiency | • Minimum Discharge Limit<br>• Minimum Charge Limit<br>• Discharge Ramp Rate<br>• Charge Ramp Rate |
| Table 4-7 | Additional Parameters | Various |

The bidding parameters, as indicated in the tables below, can generally be submitted in two ways: (1) bid elements, or (2) master file parameters. Parameter values submitted as bid elements are specific to a given market interval and can be expected to change between market intervals. In contrast, master file parameters can represent a relatively static operational limit, and RTO/ISO's may impose limits on the update frequency (e.g., on an annual basis).

Many of the proposed bidding parameters from each of the six RTO/ISO's are either identical to those indicated in the Final Rule, or differ only in the naming of the parameter. However, the approaches proposed by CAISO, PJM, and, to a more limited extent, NYISO to the use of a large portion of the bidding parameters stands out.

CAISO proposed that the need to submit values for a range of bidding parameters would be left to the discretion of the storage resource owner (CAISO, 2018). These parameters include to the Minimum/Maximum State of Charge, Minimum Charge/Discharge Limits (i.e., CAISO's proposed Minimum Load parameter) and Ramp Rates. Conversely, the Minimum/Maximum Charge Times and Minimum/Maximum Run Times would not be accepted. Limits related to the optional parameters, if submitted, would be respected during the dispatch schedule optimization runs, whereas the limits represented by the unaccepted parameters would need to be managed indirectly via other parameter values and bid submissions elements (e.g., State of Charge Limits, Minimum/Maximum Energy Limits and the submitted bid curves).

In a similar fashion CAISO does not require submission of Minimum/Maximum State of Charge, Minimum/Maximum Charge Times and Minimum/Maximum Run Times. However, these parameter values would not be utilized in any fashion during the dispatch schedule optimization runs. Management of such physical and operational limits are instead explicitly left to the storage resource owner *via* the indirect controls provided by self-management of the resource's State of Charge.

**Table 4-4:** Bid Parameters: Charge States and Rates

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | | |
|---|---|---|---|---|---|
| | State of Charge | Maximum State of Charge | Minimum State of Charge | Maximum Charge Limit | Maximum Discharge Limit |
| CAISO | **State of Charge**<br>If State of Charge is managed by CAISO, value is provided through bidding and master file parameters<br>If State of Charge is self-managed, value is provided through bidding only<br>NGR's allowed to include in bids; if not included, CAISO utilizes previous state of charge<br>If providing ancillary services, must provide telemetered value every four seconds | **Maximum State of Charge**<br>Not required to be submitted if NGR self-manages state of charge and charge/ discharge limits<br>If submitted, market optimization process respects limits<br>Filed as a master file parameter | **Minimum State of Charge**<br>Not required to be submitted if NGR self-manages state of charge and charge/ discharge limits<br>If submitted, market optimization process respects limits<br>Filed as a master file parameter | **Maximum Charge Limit**<br>Not required to be submitted if NGR self-manages state of charge and charge/ discharge limits<br>If submitted, market optimization process respects limits<br>Filed as a master file parameter | **Maximum Discharge Limit**<br>Not explicitly mentioned, but presumably managed in identical fashion as Maximum Charge Limit |
| ISO-NE | **Available Energy**<br>MWh's of stored energy available for economic dispatch<br>Corresponds to State of Charge minus Minimum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities<br>**Available Storage**<br>MWh's of unused storage available for economic dispatch of consumption<br>Corresponds to State of Charge minus Maximum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities | | | **Maximum Consumption Limit**<br>Provided by all DARD's as part of Demand Bids in DA and RT Energy Markets | **Economic Maximum Limit**<br>Provided by all GA's as part of Supply Offers in DA and RT Energy Markets |

**Table 4-4:** Bid Parameters: Charge States and Rates (cont'd)

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | | |
|---|---|---|---|---|---|
| | **State of Charge** | **Maximum State of Charge** | **Minimum State of Charge** | **Maximum Charge Limit** | **Maximum Discharge Limit** |
| MISO | **State of Charge**<br>Market dispatch will monitor during normal and Emergency system conditions<br>Parameter must be managed by ESR's (not MISO) | **Maximum Energy Storage Level**<br>Market dispatch will enforce during normal system conditions | **Minimum Energy Storage Level**<br>Market dispatch will enforce during normal system conditions | **Hourly Economic Maximum Charge Limit**<br>Market dispatch will enforce during normal system conditions | **Hourly Economic Maximum Discharge Limit**<br>Market dispatch will enforce during normal system conditions |
| | | **Emergency Maximum Energy Storage Level**<br>Market dispatch will enforce during Emergency system conditions | **Emergency Minimum Energy Storage Level**<br>Market dispatch will enforce during Emergency system conditions | **Hourly Emergency Maximum Charge Limit**<br>Market dispatch will enforce during Emergency system conditions | **Hourly Emergency Maximum Discharge Limit**<br>Market dispatch will enforce during Emergency system conditions |
| NYISO | **Beginning Energy Level**<br>Provided for both DA and RT markets<br>Represents Energy Level at the beginning of a market interval | **Upper Storage Limit**<br>Provided for both DA and RT markets<br>Newly implemented for ESR's | **Lower Storage Limit**<br>Provided for both DA and RT markets<br>Newly implemented for ESR's | **Lower Operating Limit**<br>Minimum MW level an ESR is willing to operate<br>Reflects both charging (negative value) and discharging (positive value) limits<br>Can be set lower than 0 MW if bidding to withdraw Energy<br>Provided for both DA and RT markets | **Upper Operating Limit**<br>Maximum MW level an ESR is willing to operate<br>Reflects both charging (negative value) and discharging (positive value) limits<br>Can be set lower than 0 MW if bidding to withdraw Energy<br>Must submit corresponding Normal and Emergency Upper Operating Limits (no greater than Upper Operating Limit)<br>Provided for both DA and RT markets |

**Table 4-4:** Bid Parameters: Charge States and Rates (cont'd)

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | | |
|---|---|---|---|---|---|
| | State of Charge | Maximum State of Charge | Minimum State of Charge | Maximum Charge Limit | Maximum Discharge Limit |
| PJM | **State of Charge**<br>Required to be telemetered in real time for all ESR's<br>Data will not be used to optimize ESR use across energy market intervals | **Maximum State of Charge**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model | **Minimum State of Charge**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model | **Maximum Charge Limit**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range | **Maximum Discharge Limit**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range |
| SPP | **State of Charge**<br>Used for RT Balancing Market (RTBM)<br>Instantaneous values obtained from telemetered data – thus, not really a submitted parameter | **Maximum State of Charge** | **Minimum State of Charge** | **Maximum Charge Limit**<br>For normal operating conditions | **Maximum Discharge Limit**<br>For Emergency Condition |
| | **State of Charge Forecasted**<br>Used for DA Market and DA Reliability Unit Commitment (RUC)<br>Project value for beginning of each market interval | | | **Maximum Emergency Charge Limit**<br>For normal operating conditions | **Maximum Emergency Discharge Limit**<br>For Emergency Condition |

**Table 4-5:** Bid Parameters: Operational Durations

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | |
|---|---|---|---|---|
| | **Minimum Charge Time** | **Maximum Charge Time** | **Minimum Run Time** | **Maximum Run Time** |
| CAISO | **N/A**<br>Managed through the optional state of charge parameters, minimum and maximum continuous energy limits and submitted bid curve | | | |
| ISO-NE | **Minimum Run Time**<br>Must be included in offer/bid data for GA's and DARD's, respectively, in DA and RT Energy Markets<br>Binary Storage Facilities value must be no more than 1 hour<br>Required value of 0 for CSF (always committed) | **Available Energy**<br>MWh's of stored energy available for economic dispatch<br>Corresponds to State of Charge minus Minimum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities<br>**Available Storage**<br>MWh's of unused storage available for economic dispatch of consumption<br>Corresponds to State of Charge minus Maximum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities | **Minimum Run Time**<br>Must be included in offer/bid data for GA's and DARD's, respectively, in DA and RT Energy Markets<br>Binary Storage Facilities value must be no more than 1 hour<br>Required value of 0 for CSF (always committed) | **Available Energy**<br>MWh's of stored energy available for economic dispatch<br>Corresponds to State of Charge minus Minimum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities<br>**Available Storage**<br>MWh's of unused storage available for economic dispatch of consumption<br>Corresponds to State of Charge minus Maximum State of Charge<br>Value to be telemetered for both Continuous and Binary Storage Facilities |
| MISO | **Minimum Charge Time**<br>Newly defined parameter<br>Parameters will be accepted, but must be managed by ESR through other parameters (limits to commitment algorithm and State of Charge management by ESR's) | **Maximum Charge Time**<br>Newly defined parameter<br>Parameters will be accepted, but must be managed by ESR through other parameters (limits to commitment algorithm and State of Charge management by ESR's) | **Minimum Discharge Time**<br>Minimum Run Time already defined, but unique parameter provided for ESR's<br>Parameters will be accepted, but must be managed by ESR through other parameters (limits to commitment algorithm and State of Charge management by ESR's) | **Maximum Discharge Time**<br>Maximum Run Time already defined, but unique parameter provided for ESR's<br>Parameters will be accepted, but must be managed by ESR through other parameters (limits to commitment algorithm and State of Charge management by ESR's) |

**Table 4-5:** Bid Parameters: Operational Durations (cont'd)

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | |
|---|---|---|---|---|
| | **Minimum Charge Time** | **Maximum Charge Time** | **Minimum Run Time** | **Maximum Run Time** |
| NYISO | **N/A**<br>Not required: ESR's considered dispatch-only resources | | | |
| PJM | **Minimum Charge Time**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model | **Maximum Charge Time**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model | **Minimum Run Time**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model | **Maximum Run Time**<br>Not required to be submitted<br>Parameters will not be used to make commitment decisions when using the ESR Participation model |
| SPP | **Minimum Charge Time**<br>New parameter reflecting bi-directional nature of MSR's | **Maximum Charge Time**<br>New parameter reflecting bi-directional nature of MSR's | **Minimum Discharge Time**<br>New parameter reflecting bi-directional nature of MSR's | **Maximum Discharge Time**<br>New parameter reflecting bi-directional nature of MSR's |

**Table 4-6:** Bid Parameters: Improved Service Procurement Efficiency

<table>
<tr><th rowspan="2">ISO/RTO</th><th colspan="4">ISO/RTO-Specific Proposed Parameter Name and Description</th></tr>
<tr><th>Minimum Discharge Limit</th><th>Minimum Charge Limit</th><th>Discharge Ramp Rate</th><th>Charge Ramp Rate</th></tr>
<tr><td>CAISO</td><td colspan="2">Minimum Load<br>Not required to be submitted<br>Minimum sustained operating level at which it can operate at a continuous sustained level<br>Filed as a master file parameter<br>NGR can submit values for both charging and discharging</td><td colspan="2">Ramp Rate<br>Not required to be submitted<br>Can be filed as a bid component or master file parameter<br>Specific ramp rates can be provided: Operational (for supply), Regulation, and Operating Reserve (for Spin and Non-Spin)<br>NGR’s can submit two segments for their ramp rates for discharging (above 0) and charging (below 0)</td></tr>
<tr><td>ISO-NE</td><td>Economic Minimum Limit<br>Provided by all DARD’s as part of Demand Bids in DA and RT Energy Markets<br>Required value of 0 MW for CSF (fully dispatchable)</td><td>Minimum Consumption Limit<br>Provided by all GA’s as part of Supply Offers in DA and RT Energy Markets<br>Required value of 0 MW for CSF (fully dispatchable)</td><td>Manual Response Rate<br>Rate at which the GA is capable of changing<br>Must be included in offer/bid data for GA’s and DARD’s, respectively, in DA and RT Energy Markets</td><td>Manual Response Rate<br>Rate at which the DARD is capable of changing<br>Must be included in offer/bid data for GA’s and DARD’s, respectively, in DA and RT Energy Markets</td></tr>
<tr><td rowspan="2">MISO</td><td>Hourly Economic Minimum Charge Limit<br>Market dispatch will enforce during normal system conditions</td><td>Hourly Economic Minimum Discharge Limit<br>Market dispatch will enforce during normal system conditions</td><td rowspan="2">Hourly Discharge Ramp Rate<br>Rate for moving from zero output to Hourly Economic Maximum Discharge Limit and/or from the Hourly Economic Maximum Discharge Limit to zero output<br>Used in Day-Ahead Energy and Operating Reserve Market, and all Reliability Assessment Commitment processes</td><td rowspan="2">Hourly Charge Ramp Rate<br>Rate for moving from zero output to Hourly Economic Maximum Charge Limit and/or from the Hourly Economic Maximum Charge Limit to zero output<br>Used in Day-Ahead Energy and Operating Reserve Market, and all Reliability Assessment Commitment processes</td></tr>
<tr><td>Hourly Emergency Minimum Charge Limit<br>Market dispatch will enforce during Emergency system conditions</td><td>Hourly Emergency Minimum Discharge Limit<br>Market dispatch will enforce during Emergency system conditions</td></tr>
</table>

**Table 4-6:** Bid Parameters: Improved Service Procurement Efficiency (cont'd)

| ISO/RTO | ISO/RTO-Specific Proposed Parameter Name and Description | | | |
|---|---|---|---|---|
| | **Minimum Discharge Limit** | **Minimum Charge Limit** | **Discharge Ramp Rate** | **Charge Ramp Rate** |
| NYISO | **Lower Operating Limit**<br>Minimum MW level an ESR is willing to operate<br>Reflects both charging (negative value) and discharging (positive value) limits<br>Can't be set lower than 0 MW if not bidding to withdraw Energy<br>Provided for both DA and RT markets | **Upper Operating Limit**<br>Maximum MW level an ESR is willing to operate<br>Reflects both charging (negative value) and discharging (positive value) limits<br>Can be set lower than 0 MW if bidding to withdraw Energy<br>Must submit corresponding Normal and Emergency Upper Operating Limits (no greater than Upper Operating Limit)<br>Provided for both DA and RT markets | **Response Rates**<br>Represents how quickly an ESR can respond to dispatch instructions under a variety of operating conditions<br>Can represent either speed going from zero output to Maximum Charge Limit or zero output to Maximum Discharge Limit | |
| PJM | **Minimum Discharge Limit**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range | **Minimum Charge Limit**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range | **Discharge Ramp Rate**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range | **Charge Ramp Rate**<br>Used for offering in the Day-ahead Energy Market and RT Energy market (via RT parameter updates)<br>Necessary to ensure ESR dispatch within operational range |
| SPP | **Minimum Discharge Limit**<br>Identical to Final Rule definition | **Minimum Emergency Discharge Limit**<br>Identical to Final Rule definition | **Minimum Charge Limit**<br>Identical to Final Rule definition | **Minimum Emergency Charge Limit**<br>Identical to Final Rule definition |

**Table 4-7:** Bid Parameters: Additional Parameters

| RTO/ISO | Parameter Name | Parameter Details |
|---|---|---|
| CAISO | **Minimum Load Value** | Minimum sustained operating level at which it can operate at a continuous sustained level<br>Not required to be submitted<br>All supply and demand models can submit values |
| ISO NE | **Minimum Down Time** | Required for Binary Storage Facilities only<br>Value must be no more than 1 hour<br>CSF offer parameter value of 0 only (always committed) |
| | **Notification Time plus Start-up Time** | Required for Binary Storage Facilities only<br>Value must be no more than 1 hour<br>CSF offer parameter value of 0 only (always committed) |
| | **Start-up Fee** | CSF offer parameter value of 0 only (always committed) |
| | **No-Load Fee** | CSF offer parameter value of 0 only (always committed) |
| | **Maximum Daily Energy Limit** | Maximum amount of MWh's expected to generate in the next Operating Day<br>Applicable to Limited Energy Resources only<br>Submitted for DA Energy Market Bids only |
| | **Maximum Daily Consumption Limit** | Maximum number of MWh's expected to consume in the next Operating Day<br>Applicable to DARD's only<br>Submitted for DA Energy Market Bids only |

**Table 4-7:** Bid Parameters: Additional Parameters (cont'd)

| RTO/ISO | Parameter Name | Parameter Details |
|---|---|---|
| SPP | **Energy Storage Resource Loss Factor** | Round-trip efficiency related to the amount of Energy an ESR loses from charge to discharge<br>Used by DA market and DA RUC |
| | **Min-to-Off Time** | Time that it takes to shut down (charging or discharging)<br>Applicable to all resources |
| MISO | **Hourly Regulation Maximum Charge Limit** | Maximum withdrawal level at which an ESR can respond to automatic control signals |
| | **Hourly Regulation Minimum Charge Limit** | Minimum withdrawal level at which an ESR can respond to automatic control signals |
| | **Hourly Regulation Maximum Discharge Limit** | Maximum injection level at which an ESR can respond to automatic control signals |
| | **Hourly Regulation Minimum Discharge Limit** | Minimum injection level at which an ESR can respond to automatic control signals |
| | **Hourly Electric Storage Resource Efficiency Factor** | Operating characteristic of an ESR that is the amount of increase in Energy Storage Level for each 1 MW of Charge Energy withdrawn by that ESR |
| NYISO | **Roundtrip Efficiency** | Ratio of energy injections to energy withdrawals |

NYISO uses a similar, but more limited approach, to the time-related bidding parameters: Minimum/Maximum Charge Time and Minimum/Maximum Run Time (NYISO, 2018b). Submission of these bidding parameters is not required by NYISO for Energy Storage Resources. The optional nature of these parameters is primarily derived from the explicit categorization of the Energy Storage Resource as a dispatch-only resource; Charge Time and Run Time parameters are more typically used for resources participating in the commitment process. NYISO does indicate that incorporation of Charge Time and Run Time operational limits could occur indirectly through use of the Beginning Energy Level and Roundtrip Efficiency bidding parameters to ensure development of feasible dispatch schedules.

The Order did provide RTO/ISO's with flexibility to incorporate aspects of the thirteen bidding parameters, ensuring the physical and operation characteristics of storage resources are appropriately reflected in bid submissions. It is unclear if an extensive use of indirect controls for many operational limits normally represented by bidding parameters can be demonstrated to provide sufficiently robust assurances that dispatch schedules will be feasible or that indirect controls won't present a wholesale market participation challenge that is unique to ESR's. Section 4.4, below, discusses initial Commission feedback on some of these approaches.

Several other RTO/ISO's have incorporated unique features into their bidding parameter proposals that are also worth noting. Both MISO and SPP have proposed use of a parallel set of parameters for some operation limits that are specific to Emergency Operating conditions (FERC, 2019c; MISO, 2018). This concern about distinctly represent emergency conditions does not seem isolated to storage resources in these authorities; further research into the origin of explicit emergency limits within MISO and SPP may be instructive as to why other RTO/ISO's have not deemed equivalent parameters necessary to ensure reliable transmission system operation.

ISO-NE has taken a unique approach to submitting information on operational states and limits by using two derived parameter values, Available Energy and Available Storage (ISO-NE, 2018c). These values are a conglomeration of the resource's State of Charge and Minimum/Maximum State of Charge limits, and are directly applied to reporting the associated State of Charge Limits. They are also used as an indirect representation of the Maximum Charge/Run Time Parameters. As previously discussed, it is not yet clear how robust such indirect measure are for ensuring determination of feasible dispatch schedules or for complying with the Final Rule requirements (See Section 4-4 below).

Finally, three of the RTO/ISO's have felt it beneficial, or even necessary, to implement some form of bidding parameter related to storage resource charging efficiency. Thus MISO, NYISO and SPP have all implement parameters reflective of the round-trip efficiency of the storage resources (FERC, 2019c; MISO, 2018; NYISO, 2018b). In each of these cases, submission of an efficiency parameter is mandatory and is considered necessary to developing accurate market optimization solutions.

### 4.4 Participation Model Compliance Deficiencies

On April 1, 2019, the Commission issued letters to each of the six RTO/ISO's requesting additional information needed to further process the respective compliance plans previously filed in December, 2018 (FERC, 2019b, 2019c, 2019d, 2019e, 2019f, 2019g). The RTO/ISO's are required to file responses within thirty days following the Commission's issuance of the letters or risk rejection of the compliance plan proposal filings and incurring delays in implementing the tariff changes needed to meet the compliance timeline outlined in the Final Rule.

Many of the information requests simply required provision of tariff sections citations to demonstrate that the relevant elements outlined in the compliance plans would actually be applicable to ESR's. However, assessment of the requests in these letters from the Commission can be a worthwhile effort because they represent FERC's initial official perspective on how the RTO/ISO's are approach compliance with the Final Rule. The letters may also provide a forward-looking perspective on the additional issues that the Commission is contemplating related to energy storage, but that might not be strictly in scope of the current Final Rule. In reviewing the Commission letters, the following topics, often relevant to multiple RTO/ISO's, were considered: ESR definition, ESR participation model elements, market participation eligibility, bidding parameters and minimum size requirements.

<u>ESR Definition</u>

Some RTO/ISO's took the straightforward approach of directly adopting the Final Rule's definition of an Electric Storage Resource. At the other extreme, CAISO took the equally simple path of adopting no definition in its proposed tariff; CAISO correctly points out the absence of any prescription within the Final Rule to formally adopt any such definition (CAISO, 2018).

Two RTO/ISO's did propose ESR definitions that were different from that outlined in the Final Rule, causing Commission concerns with participation constraints resulting from storage resource location constraints and the ability of aggregated storage resources to participate using an ESR participation model. First, MISO included a requirement that ESR's must by "physically located within the MISO Balancing Authority Area" (MISO, 2018). This rightfully raises the concern about discriminatory treatment of storage resources external to a balancing authority. Such a concern was likely raised because of its explicit inclusion in MISO's ESR definition, but could apply to any other RTO/ISO; other compliance plans have not seemed to clarify if external storage resources would subject to identical participation requirements as those physically residing within the balancing authority territory. Second, NYISO's definition indicated that Energy receipt and later injection must occur at the same specified location on the grid (NYISO, 2018b). Without any clarification as to what interconnection level is relevant to the definition, this requirement around injection/withdrawal co-location was viewed by the Commission as potentially preventing at least some forms of aggregated storage resources from participating in wholesale electric markets.

In both cases, the Commission has requested further clarification around the effectuation of the localization requirements in the ESR definitions. Also, as discussed below, while the Commission deferred issuing rules for aggregated DER's as part of Order No. 841, they may be using these current compliance plans as a way to probe the thinking of various RTO/ISO's on additional ways of addressing that challenging issue.

ESR Participation Model Elements

As shown in Table 4-2, and allowed per the Order, RTO/ISO's may have more than one participation model available to storage resources. However, there must be at least one participation model, or a combination of models, that comply with all of the ESR participation model requirements of the Order for all potential technologies and storage medium. Thus, CAISO was requested to confirm if any of the offered models (e.g., NGR, pumped hydro, etc.) actually complied with the Order requirements (CAISO, 2018). Similarly, ISO-NE will need to clarify if the combination of the Continuous Storage Facility and Binary Storage Facility models are sufficient to ensure the overlying ESR participation model is technology-neutral (ISO-NE, 2018c). In both case, simple additional citations of compliance may be all that is required for address FERC concerns.

Market Participation Eligibility

Several RTO/ISO's have proposed limitations on market participation eligibility for storage resources, or were silent on the ability of storage resources to provide specific services. In one example, the Commission questioned ISO-NE's proposal to disallow provision of capacity in its Forward Capacity Market (FCM) by the ESR-related energy withdrawing-DARD resource type(ISO-NE, 2018c); no such limitations were proposed for assets capable of refraining from charging by RTO/ISO's with capacity markets. ISO-NE will thus need to demonstrate the unique aspects of its market systems and processes precluding provision of capacity services by the DARD resource type.

In a similar fashion, NYISO and PJM were requested to explain the absence of opportunities for ESR's to provide specific ancillary services (e.g., reactive power and black start support for NYISO and reactive power and non-synchronized reserves for PJM) (FERC, 2019b; NYISO, 2018b). The omissions by NYISO and PJM may simply be oversights that arose during the preparation of the respective compliance plans, with resolution requiring simple revisions to the tariff updates.

PJM's response regarding non-synchronized reserves will be potentially more interesting, especially considering its requirement around single continuous bid curves for storage resources seeking to operate in a Continuous commitment status. As discussed in Section 4-2 above, such storage resources would not be permitted to provide start-up or ramp rate limitations, and are thus required to be dispatchable at any point along a submitted bid curve for the requested market interval. This continuous dispatchability is equivalent to requiring a continuously synchronized state for the storage resource in the respective market intervals.

It then becomes less clear how storage resources with finite start-up costs and ramp rates could be eligible to provide the full range of services for which they were technically capable of (e.g., non-synchronized reserves) using these functionally dispatch-only participation models. Therefore, there may be opportunities for the Commission to challenge whether the fairly broad requirement for continuous bid curves is sufficient to comply with all elements of the Final Rule. In fact, FERC also approached this issue from the perspective of make-whole payments related to commitment (e.g., start-up and no-load) costs, explicitly questioning NYISO if a dispatch-only model accurately reflects such costs as it would for generators using existing participation models (NYISO, 2018b).

Bidding Parameters

Several RTO/ISO's chose to implement bidding parameters that were identical to those outlined in the Final Rule, or simply differing minor naming differences that were clearly connected to the equivalent Final Rule parameters.  Three RTO/ISO's proposed alternate approaches where the Commission felt the justifications provided in the respective compliance plans were not sufficient to fully demonstrated compliance.  As discussed in Section 4-3 above, CAISO and PJM have proposed to make submission of a large number of the bidding parameters optional, instead relying State of Charge self-management and other key bidding parameters to ensure assignment of feasible dispatch instructions to storage resources.  The additional questions on the capability of such an approach (CAISO, 2018; FERC, 2019b) seems to be an indication that the Commission is not yet convinced about the robustness of CAISO and PJM's proposal to ensure provision of reliably feasible dispatch instructions.

Delving somewhat into the details of the proposals' mechanics, FERC requested that ISO-NE provide additional information on their proposed use the derived parameters, Available Energy and Available Storage (ISO-NE, 2018c).  ISO-NE's compliance plan would require provision of these bidding parameters *via* real-time telemetry instead of through market interval-specific offers from storage resource owners.  Therefore, it isn't clear how ISO-NE would be able to develop feasible solutions for future market intervals if they are not receiving any forward-looking values for the Available Energy and

Available Storage parameters; other RTO/ISO's may need to be cautious about relying solely on real-time data if the underlying parameters is also needed to establish schedules for future market intervals.

<u>Minimum Size Requirements</u>

Most compliance plan elements specific to addressing the minimum resource size requirements were themselves not controversial, with all RTO/ISO's presenting their proposals for reducing resource size requirements to that called for in the Final Rule: 100 kW. The Commission did use the issue of minimum size requirements to request additional information related to resource aggregation, even when such tariff elements were not directly discussed in the compliance plans. Specifically, ISO-NE and PJM were both asked to explain whether resources smaller than 100 kW could be aggregated to meet the minimum size requirements (FERC, 2019b; ISO-NE, 2018c); neither compliance plan had directly addressed aggregated resources. Continued engagement between ISO-NE, PJM and FERC as they resolve outstanding concerns expressed in the Commission's letters may provide further elucidation on the FERC's expected outcome from inquiries into storage resource aggregation as it applies to Order No. 841 compliance.

### 4.5 Conclusions

With the filing of the Order No. 841 compliance plans by the six in-scope RTO/ISO's in late 2018, the planned efforts to remove barriers to electric storage resources in wholesale markets are coming into view. The compliance plans provide not just the proposed tariff revisions necessary to introduce the ESR participation models and pricing for ESR charging, but also the justifications offered by the respective RTO/ISO's attempting to demonstrate full compliance with the Final Rule requirements. Each RTO/ISO proposed the use of one or more participation model that a storage resource could be qualified for, with some utilizing additional resource types that are typically used to further define operational functions within a given participation model. Several RTO/ISO's leveraged efforts initiated prior to Order No. 841 becoming effective as a basis for elements of their compliance plans; other RTO/ISO's that might not have had significant experience with newer storage technologies more or less adopted participation model elements directly from the Final Rule.

Looking at the proposed participation models on a very granular basis, the RTO/ISO's allow varied roles for ESR's in their respective unit commitment processes and dispatch. Generally, some form of restriction has been placed on how ESR's are considered in the unit commitment process, typically resulting in consideration of ESR's as dispatch-only resources. These restrictions are either implicitly (e.g., submission of continuous bid curves covering their full operational range when wishing to bid as both energy injecting (supply) and withdrawing (load) resources) or explicitly (e.g., NYISO's exclusion of Energy Storage Resources from the commitment process and designation as dispatch-only resources on Energy Markets) limit ESR's to being available for only continual dispatch in a given market interval.

Proposed bidding parameters were tabulated and compared to the associated requirements in the Final Rule. Most of the parameters from each of the six RTO/ISO's are either identical to those indicated in the Final Rule, or differ in the proposed parameter naming convention. However, some notable differences were identified.

CAISO, PJM, and, to a more limited extent, NYISO proposed that submission of a range of bidding parameters would optional. These RTO/ISO's would then rely on indirect control of associated operational limits (e.g., through bid curves, other operational limits, State of Charge self-management, etc.) to ensure development of feasible dispatch schedules. It is unclear if such an approach can demonstrate sufficiently robust assurances that dispatch schedules will be feasible or not present wholesale market participation barriers unique to ESR's. Additional bidding parameters not mentioned in the Final Rule have been proposed, including those reflecting round-trip charging efficiency and emergency operation capabilities.

Instances where specific operational limits, especially those related to charging and running times, would not be allowed to be submitted or respected during the unit commitment process where identified. Such parameters are largely those utilized in the unit commitment process, further emphasizing the need for ESR's to serve as dispatch-only resources in the proposed participation models.

A review of the additional information requests made by FERC in early April, 2019 was also performed, identifying some of the Commission's outstanding compliance concerns with the proposed compliance plans. Topics related to ESR definition, ESR participation model elements, market participation eligibility, eligibility to participate as buyer/seller, bidding parameters and minimum size requirements will require further response from the RTO/ISO's in order to ensure timely approval of the compliance plans. Questions were raised regarding the ability of participation models with continuous bid curves requirements, potential lack of run-time parameter submission, and no allowance for start-up costs can truly provide ESR's with participation opportunities that storage technology-neutral and reliably ensure feasible dispatch schedules. Initial response from the RTO/ISO's on these questions will be available shortly, and hopefully providing a glimpse into the extent of future work needed to ensure full compliance with the Final Rule's requirements.

# Chapter 5 <u>Conclusions</u>

This study has attempted to deepen the understanding of the requirements of and responses to Order No.841. Understanding the impact of the Final Rule presented by the Order on the growth of electric storage capacity in the US is a timely endeavor; the presence of new storage technologies on the US electric system continues to grow and RTO/ISO's are expected to begin implementation of their associated compliance plans in 2019.

This analysis was developed using the rich sources of information related to the Order that became available over the last few years. These sources have primarily included: (1) the Commission's documented history on development of the Final Rule, (2) contents of the Final Rule itself, (3) FERC's embedded jurisdictional claims and related legal precedents, (4) the RTO/ISO's compliance plans, and (5) FERC's compliance deficiency letters provided to the RTO/ISO's.

## <u>Final Rule Requirements and Participation Model Effectiveness</u>

A summary of the Final Rule that became effective in early 2018 with the issuance of Order No 841 by FERC has been provided in this report. The elements of the Final Rule are primarily intended to provide a mechanism that can ensure electric storage resources are able to participate in wholesale electricity markets to an extent that is reflective of a resource's physical and operation characteristics. Realizing the distinctive capabilities that electric storage resources possess relative to existing wholesale market participants, the Commission utilizes a participation model concept as this mechanism.  Building on the definition for an electric storage resource, the associated ESR participation model consists of four required elements:

1. Service Provision Eligibility
2. Wholesale Market Price Setting
3. Market Bidding Parameters
4. Minimum Size Requirements

Additionally, the Final Rule provides clear compensation requirements (i.e., pricing at the relevant nodal LMP) for specific types of energy withdrawals: those performed for the purpose of charging ESR's that re-inject energy back to the grid as part of later wholesale transactions.  The Final rule thus differentiates such energy withdrawals from conventional loads and end-use applications.  The wholesale nature of these distinctly ESR-associated energy withdrawals is now definitively established so as to not unfairly disadvantage storage resources when providing grid services *via* wholesale markets.

The Commission has made increasing use of resource-specific participation models in an effort to broaden wholesale market participation.  Broader participation is seen as a path to increased market competition and, ultimately, the lower electricity rates that FERC looks for in order to comply with the FPA's requirement for just and reasonable rates.  Participation models can at least partially achieve this intended goal.  The Final Rule's effect on market competition will be achieved primarily through a greater realization of merchant value by ESR owners.  Full system benefits derived from storage resources extend beyond those revenues realized by ESR owners.  Therefore, economically optimal levels of ESR capacity and service provision will likely not be achieved through exclusive use of participation models.

It is additionally noted that participation models, as currently constructed, are revenue/benefit-centric mechanisms; the models provide neither subsidization of new technology research and development, nor any direct procurement incentives (e.g., procurement credits or financing assistance). Thus, exclusive use of participation models to facilitate ESR capacity growth does not provide any direct downward pressure on procurement costs that would further improve benefit/cost considerations that are critical to many project valuation processes (e.g., cost effectiveness tests detailed in the California Standard Practice Manual (CPUC, 2001)).

Order No. 841 is thus an important step towards attaining greater electric storage resource service provision, and by extension, enabling the concomitant expansion of renewable energy penetration. However, unilateral federal efforts alone are unlikely to provide the stimulus needed to achieve economically-optimal utilization of ESR's and a direct impact on all aspects of benefit/cost considerations related to ESR procurement.

Final Rule Legal Foundations and Jurisdictional Perspectives

Realization of ESR participation model-derived benefits will be heavily dependent on the long-term resilience of the market changes that FERC intends to implement through Order No. 841. The Commission has proactively responded to the technological, economic and legislative shifts through its efforts on Order No. 841. Yet, FERC has still relied primarily on a conventional, categorical exercise of its jurisdiction over interstate wholesale markets when regulating sub-transmission-level connected ESR's through

Order No. 841's requirements. The same shifts that prompted its work on Order No. 841 are the same ones that present the Commission with increasing vulnerability to judicial review of its jurisdictional approach cited in the Final Rule and the regulatory regime change.

The Commission must now take greater care not to overstep its authorized jurisdiction by inadvertently enacted regulations that directly impact retail activities of storage resources that are simultaneously interacting in wholesale electric markets. Such regulatory efforts by FERC risk judicial review to determine if federal actions have unlawfully preempted the authorities clearly reserved for the States in the Federal Power Act. Overturning established market structures, and the associated increase in regulatory uncertainty, will drive increasing investment gaps in the development and commissioning of electric storage resources.

An increasing engagement with the respective State authorities is needed from FERC to maintain the momentum that Order No. 841 provides to ESR participation, both at the wholesale and retail level. Alternate approaches to FERC's current jurisdictional practices will be needed to achieve this as well. For example, the efforts to date at implementing state-level legislation and mandates associated with electric storage procurement point to the potential effectiveness of the innovative incubation environments provided at the state level. Such innovation can be a driving force leading to new mature, commissioned technological innovations that the Commission is seeking as a way to increase competition in interstate wholesale electric markets. Harnessing best-practices and, where possible, aligning with state-level efforts can hasten the realization of the system-wide benefits that better reflect the full range of services available from ESR's.

At the same time, unintended reliability risks to the electric system can come from market and grid performance driven by distributed energy resources (e.g., ESR's), forcing the slowing or outright halt to storage resource participation growth. State/local entities that operate and regulate the sub-transmission levels of the grid need some level of awareness of distribution-level and BTM resource interactions in wholesale markets to ensure proper system operation and planning. Thus, the need for cooperative federal- and state-level engagement on ESR participation will only increase as ESR capacity and utilization increases.

RTO/ISO Compliance Plans and Initial Commission Responses

Details of the various storage resource participation models, as proposed by the six RTO/ISO's in the December, 2018 compliance plan submissions, were tabulated along with associated resource types, where applicable. Some RTO/ISO's leveraged efforts pre-dating Order No. 841 as key elements of one or more proposed ESR participation model (e.g., CAISO, PJM and ISO-NE). Conversely, some RTO/ISO's had little or no previous experience with non-PHES resource participation in the relevant wholesale markets (e.g., SPP); such regions relied more heavily on direct adoption of the Final Rule participation model elements.

A review of bidding parameters revealed two aspects of the proposed participation models that RTO/ISO's may need to resolve to the satisfaction of the Commission in order to ensure timely approval of the proposed compliance plans. First, the proposals by some RTO/ISO's to make extensive use of indirect controls as a means to manage numerous ESR physical parameters is not yet sufficiently justified. As evident in the Commission's compliance letters sent to the RTO/ISO's in early April, 2019, it is not yet clear how the proposed indirect controls will provide sufficient assurance that feasible dispatch instructions can be reliably issued under a wide range of operational situations.

The categorization of some proposed participation models as "dispatch-only", or the requirement to submit continuous bid curves across an ESR's entire charging/discharging operational range, represents a possible hurdle to FERC's approval of the compliance plans for most RTO/ISO's. The ESR definition in the Final Rule is agnostic to the use of specific storage technology, only requiring a resource to have the ability to store energy for later injection to the grid. Yet, storage resources excluded from functional participation in unit commitment processes, or limited in to submitting either charging or discharging bids in a given market interval can provide barriers to storage resources. These barriers can be associated with specific operational limitations (e.g., non-zero start-up times, finite ramp rates, etc.) or entitlement to market participation costs (e.g., start-up costs, no-load costs, etc.). Overcoming this technology bias may be significant for some RTO/ISO's. For example, NYISO's claimed market optimization software limitations may require significant cost and time to accommodate even small numbers of storage resource that can't submit continuous bid curves. However, greater sharing of best-practices regarding inclusion of ESR operational characteristics may be used to provide easier solutions to achieving true technology neutrality for the ESR participation models; consideration of CAISO's claimed ability to respect all operational limits, even with submission of continuous bid curves, may hold valuable lessons for other RTO/ISO's.

# Chapter 6 Literature Cited


A6571, New York State Assembly (2017).

AB2514, California Assembly § Part 2, Division 1 (2010).

AB2868, California Assembly § 2838 (2016).

Administrative Procedure Act, 5 U.S.C. § 706 (1946).

APPA/NRECA. (2017). Comments of the American Public Power Association and the National Rural Electric Cooperative Association on Notice of Proposed Rulemaking. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538818

Barbour, E., Wilson, I. A. G., Radcliffe, J., Ding, Y., & Li, Y. (2016). A review of pumped hydro energy storage development in significant international electricity markets. *Renewable and Sustainable Energy Reviews, 61*, 421-432. Retrieved from https://dx.doi.org/10.1016/j.rser.2016.04.019. doi:10.1016/j.rser.2016.04.019

Bouwman H., F. E., Haaker T., Kijl B., De Reuver M. (2008). *Conceptualizing the STOF model*. Berlin, Heidelberg: Springer Publishers.

Bresler, F. S. (2014). *Energy and Ancillary Services Uplift in PJM*. Retrieved from https://www.ferc.gov/CalendarFiles/20140905085408-PJM%20%20Whitepaper.pdf

CAISO. (2018). California Independent System Operator Corporation Docket No. ER19-468-000, Compliance with Order No. 841. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14725307

California Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395 (U.S. Court of Appeals for the District of Columbia Circuit 2004).

Chang, J., Pfeifenberger, J., Spees, K., Davis, M., Karkatsouli, I., Regan, L., & Marshall, J. (2015). *The Value of Distributed Electricity Storage in Texas*. Retrieved from https://brattlefiles.blob.core.windows.net/files/5977_the_value_of_distributed_electricity_storage_in_texas_-_proposed_policy_for_enabling_grid-integrated_storage_investments_full_technical_report.pdf

*Comments of Advanced Microgrid Solutions, Inc. (Docket Nos. RM16-23-000; AD16-20-000; Order No. 841)*. (2017).

*Comments of the Energy Storage Association (Docket Nos. RM16-23-000; AD16-20-000; Order No. 841)*. (2017).

CPUC. (2001). *California Standard Practice Manual; Economic Analysis of Demand-Side Programs and Projects*, Retrieved from https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

CPUC. (2013). *Decision 13-10-040: Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems (Rulemaking 10-12-007)*, Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

CPUC. (2018). *Resolution E-4949. Pacific Gas and Electric request approval of four energy storage facilities with the following counterparties: mNOC, Dynegy, Hummingbird Energy Storage, LLC, and Tesla.*, E-4949. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M240/K050/240050937.PDF

De Martini, P., & Kristov, L. (2015). Distribution Systems in a High Distributed Energy Resources Future. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=edssch&AN=edssch.qt6689n6x1&site=eds-live&scope=site&custid=s3818721.

Denholm, P., Ela, E., Kirby, B., & Milligan, M. (2010). *The Role of Energy Storage with Renewable Energy Generation*, United States

Dennis, J. S., Kelly, S. G., Nordhaus, R. R., & Smith, D. W. (2016). Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies. Retrieved from http://www.escholarship.org/uc/item/2cb8p55p

DTE Energy. (2017). MOTION TO INTERVENE AND COMMENTS OF DTE ELECTRIC COMPANY AND CONSUMERS ENERGY COMPANY. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538741

EIA. (2010). Form EIA-860 detailed data with previous form data (EIA-860A/860B); 2010 Report. Retrieved April 22, 2019 https://www.eia.gov/electricity/data/eia860/

EIA. (2016a). Annual Electric Power Industry Report, Form EIA-861; 2016 Report. Retrieved March 13, 2019 https://www.eia.gov/electricity/data/eia861/

EIA. (2016b). Form EIA-860 detailed data with previous form data (EIA-860A/860B); 2016 Report. Retrieved April 22, 2019 https://www.eia.gov/electricity/data/eia860/

EIA. (2016c). Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860); Dec, 2016 Report. Retrieved March 13, 2019 https://www.eia.gov/electricity/data/eia860m/

EIA. (2017a). Annual Electric Power Industry Report, Form EIA-861; 2017 Report. Retrieved March 13, 2019 https://www.eia.gov/electricity/data/eia861/

EIA. (2017b). Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860); Dec, 2017 Report. Retrieved March 13, 2019 https://www.eia.gov/electricity/data/eia860m/

EIA. (2018). *U.S. Battery Storage Market Trends*, Retrieved from https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

EIA. (2019a). *Electric Power Monthly with Data for December 2018 (Table 5.1)*, Retrieved from https://www.eia.gov/electricity/monthly/

EIA. (2019b). Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860); Feb, 2019 Report. Retrieved April 30, 2019 https://www.eia.gov/electricity/data/eia860m/

Electric Power Supply Association v. Federal Energy Regulatory Commission, Docket No. 11-1486 (United States Court of Appeals for the District of Columbia Circuit 2015).

ERCOT. (2019a). ERCOT Quick Facts. Retrieved from http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_02.4.19.pdf

ERCOT. (2019b). Growth of energy storage resources in the ERCOT region. Retrieved from http://ercot.com/content/wcm/lists/164134/Storage_One_Pager_FINAL.pdf

Federal Energy Regulatory Commission v. Electric Power Supply Association et al., Docket No. 14-840 (Supreme Court of the United States 2016).

Federal Power Act, 16 U.S.C, § 824 (1935).

Federal Power Commission v. Southern Cal. Edison Co., 376 U.S. 205 (Supreme Court of the United States 1964).

FERC. (1995). *Order granting petition for declaratory order re Norton Energy Storage, LLC under EL01-70.*, 95 FERC ¶ 61,476.

FERC. (1996). *Order No. 888 Promoting Wholesale Competition Through Open Access Non- Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 FR 21540.

FERC. (2000). *Order No. 2000 Regional Transmission Organizations*, 65 FR 810

FERC. (2005). *Order No. 2006 Standardization of Small Generator Interconnection Agreements and Procedures*, 70 FR 34189

FERC. (2008a). *Order No 719-A Wholesale Competition in Regions With Organized Electric Markets; Final Rule; Order on Rehearing*, 74 FR 37775.

FERC. (2008b). *Order No 719 Wholesale Competition in Regions With Organized Electric Markets*, 73 FR 64099

FERC. (2010). *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies Docket No. AD10-13-000*,

FERC. (2011a). *Demand Response Compensation in Organized Wholesale Energy Markets*, 76 FR 16657.

FERC. (2011b). *Order No. 745 Demand Response Compensation in Organized Wholesale Energy Markets*, 76 FR 16657

FERC. (2011c). *Order No. 755 Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 76 FR 67259

FERC. (2013a). *Order No. 784 Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 78 FR 46177

FERC. (2013b). *Order No. 792 Small Generator Interconnection Agreements and Procedure*, 78 FR 73239

FERC. (2016). *Notice of Proposed Rulemaking. Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 81 FR 86522.

FERC. (2018). *Order No. 841 Final Rule re Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators under RM16-23*, 83 FR 9580.

FERC. (2019a, March 7, 2019). About FERC - Office of Energy Policy and Innovation. Retrieved from https://www.ferc.gov/about/offices/oepi.asp

FERC. (2019b). Letter informing PJM Interconnection, L.L.C. that their 12/03/18 Compliance Filing for Order No. 841 requires additional Information is necessary to process the filing under ER19-469. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14757483

FERC. (2019c). Letter informing Southwest Power Pool, Inc. that their 12/03/18 Compliance Filing for Order No. 841 requires additional information necessary to process the filing under ER19-460 et al. FERC Online eLibrary Retrieved April 8, 2019, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14725215

FERC. (2019d). Letter requesting California Independent System Operator Corporation to file additional information within 30 days re the Compliance Filing for Order No.

841 under ER19-468. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14757495

FERC. (2019e). Letter requesting ISO New England Inc., et al. to file a complete response within 30 days re the Compliance Filing for Order No. 841 under ER19-470. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14757497

FERC. (2019f). Letter requesting Midcontinent Independent System Operator, Inc. to file a complete response within 30 days re the Compliance Filing for Order No. 841 under ER19-465. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14757489

FERC. (2019g). Letter requesting New York Independent System Operator, Inc. to provide additional information re the Compliance Filing to Order No. 841 under ER19-467. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14757485

Fitzgerald, G., Mandel, J., Morris, J., & Touatl, H. (2015). *The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid*. Retrieved from https://rmi.org/insight/economics-battery-energy-storage/

Garnier, E., & Madlener, R. (2016). The Influence of Policy Regime Risks on Investments in Innovative Energy Technology. *Energy Journal, 37*, 145-160. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=bth&AN=118453495&site=eds-live&scope=site&custid=s3818721. doi:10.5547/01956574.37.SI2.egar

Gonzále, G. S. S. (2016). Evolving Jurisdiction Under the Federal Power Act: Promoting Clean Energy Policy. *UCLA Law Review, 63*(5), 1422-1470. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=a9h&AN=116431229&site=eds-live&scope=site&custid=s3818721.

H. 4568, Massachusetts House of Representative § Chapter 188 (2016).

Haaker, T., Bouwman, H., Janssen, W., & De Reuver, M. (2017). Business model stress testing: A practical approach to test the robustness of a business model. *Futures, 89*, 14-25. Retrieved from https://dx.doi.org/10.1016/j.futures.2017.04.003. doi:10.1016/j.futures.2017.04.003

HB 2193, Oregon House of Representative § Chapter 312 (2015).

ISO-NE. (2018a). *ISO New England 2017 Annual Markets Report*. Retrieved from https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf

ISO-NE. (2018b). ISO New England Inc. and New England Power Pool; Docket No. ER19-84-000; Enhanced Storage Participation Revisions. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14710825

ISO-NE. (2018c). Revisions to ISO New England Inc. Transmission Markets and Services Tariff in Compliance with FERC Order 841; Docket No. ER19-470-000. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14725331

ISO-NE. (2019a). FAQs: Locational Marginal Pricing. Retrieved from https://www.iso-ne.com/participate/support/faq/lmp

ISO-NE. (2019b). IS-ONE Key Grid and Market Stats: New England's Electricity Use. Retrieved from https://www.iso-ne.com/about/key-stats/electricity-use

Jacob, K. J. S. (2017). Energy Jurisdiction in the Twenty-First Century. *Ecology Law Quarterly, 44*(2), 45. doi:https://doi.org/10.15779/Z386D5PB2J

Kristov, L. (2015). Energy Storage in the Evolving Electric System. Retrieved from https://www.ferc.gov/CalendarFiles/20151119135437-CAISO.pdf?csrt=4651387667047461819

Lazar, J. (2016). *Electricity Regulation in the US: A Guide. Second Edition*. Retrieved from The Regulatory Assistance Project. Montpelier, VT: http://www.raponline.org/knowledge-center/electricityregulation-in-the-us-a-guide-2

Leisen, R., Steffen, B., & Weber, C. (2019). Regulatory risk and the resilience of new sustainable business models in the energy sector. *Journal of Cleaner Production*. Retrieved from https://dx.doi.org/10.1016/j.jclepro.2019.01.330. doi:10.1016/j.jclepro.2019.01.330

Lindh, F. R. (2013). State Jurisdiction Over Distribured Generators. *Energy Law Journal, 34*, 499. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=edslex&AN=edslexBE6D5C3C&site=eds-live&scope=site&custid=s3818721.

Markard, J. (2011). Transformation of Infrastructures: Sector Characteristics and Implications for Fundamental Change. *Journal of Infrastructure Systems*(3), 107. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=edsoaf&AN=edsoaf.145ccf3a34eb8dbb4357f6eb4680b9f75d387735&site=eds-live&scope=site&custid=s3818721. doi:10.1061/(ASCE)IS.1943-555X.0000056

MISO. (2018). Midcontinent Independent System Operator, Inc.'s Filing to Revise Tariff as Necessary in Compliance with Order No. 841 Docket No. ER19-465-000. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14725267

MISO. (2019). Historical Daily Forecast and Actual Load by Local Resource Zone: MISO area, 2018 (20181231_rfal_HIST.xls). https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=/MarketReportType:Summary/MarketReportName:Historical%20Regional%20Forecast%20and%20Actual%20Load%20(xls)

MISO Transmission Owners. (2017). COMMENTS OF THE MISO TRANSMISSION OWNERS. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538819

New York State. (2019). Reforming the Energy Vision. Retrieved from https://static1.squarespace.com/static/576aad8437c5810820465107/t/5aec725baa4a99171e5890d4/1525445212467/REV-fm-fs-1-v8.pdf

Nordhaus, R. R. (2015). The Hazy 'Bright Line': Defining Federal and State Regulation of Today's Electric Grid. *Energy Law Journal, 36*, 203. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=edslex&AN=edslexB77CE6AB&site=eds-live&scope=site&custid=s3818721.

NYDPS. (2018). *New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap)*. Retrieved from https://www.ethree.com/wp-content/uploads/2018/06/NYS-Energy-Storage-Roadmap-6.21.2018.pdf

NYISO. (2017). *The State of Storage; Energy Storage Resources in New York's Wholesale Electricity Markets*. Retrieved from https://www.nyiso.com/documents/20142/2225293/2017-State-Of-Storage-Report.pdf/c80da6ff-b239-3464-3b6d-f191bf62c597?utm_source=Blog&utm_medium=Blog&utm_campaign=EnergyStorage_campaign

NYISO. (2018a). *2018 Load & Capacity Data Report "Gold Book"*. Retrieved from https://www.nyiso.com/documents/20142/2226333/2018-Load-Capacity-Data-Report-Gold-Book.pdf/7014d670-2896-e729-0992-be44eb935cc2

NYISO. (2018b). New York Independent System Operator, Inc.; Compliance Filing and Request for Extension of Time of Effective Date; Docket Nos. RM16-23-000, AD16-20-000, ER19-467-000. FERC Online eLibrary, from FERC https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14725304

Pavic, I., Dvorkin, Y., & Pandžic, H. (2019). Energy and reserve co-optimisation - reserve availability, lost opportunity and uplift compensation cost. *IET Generation, Transmission & Distribution, 13*(2), 229-237. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=inh&AN=18360657&site=eds-live&scope=site&custid=s3818721. doi:10.1049/iet-gtd.2018.5480.

Peet, T., Asselin, J., & Pant, S. (2019). *Continuous Storage Facility Participation; Part of the Enhanced Storage Participation Revisions and Energy Storage Project.* Paper presented at the ISO-NE Customer Training.

PJM. (2019). PJM Data Miner 2 Hourly Load: Metered (hourly data for 1/1/2018 to 12/31/2018 for RTO market region). https://dataminer2.pjm.com/feed/hrl_load_metered/definition

Pollitt, M. G., & Anaya, K. L. (2016). Can Current Electricity Markets Cope with High Shares of Renewables? A Comparison of Approaches in Germany, the UK and the State of New York. *Energy Journal, 37*, 69-88. Retrieved from http://search.ebscohost.com/login.aspx?direct=true&AuthType=sso&db=bth&AN=118453491&site=eds-live&scope=site&custid=s3818721. doi:10.5547/01956574.37.SI2.mpol

PowerSouth Energy Cooperative. (2019). Compressed Air Energy Storage McIntosh Power Plant Retrieved from http://www.powersouth.com/wp-content/uploads/2017/07/CAES-Brochure-FINAL.pdf

Public Util. Comm. v. Attleboro Co., 273 U.S. 83 (Supreme Court of the United States 1927).

SB204, Nevada Senate (2017).

Schmid, E., Knopf, B., & Pechan, A. (2016). Putting an energy system transformation into practice: The case of the German Energiewende. *Energy Research & Social Science, 11*, 263-275. Retrieved from https://dx.doi.org/10.1016/j.erss.2015.11.002. doi:10.1016/j.erss.2015.11.002

Uria-Martinez, R., Johnson, M. M., & O'Connor, P. W. (2018). *2017 Hydropower Market Report*,

USDOE. (2018). Global Energy Storage Database.  Retrieved March, 2018, from U.S. Department of Energy https://www.energystorageexchange.org/

Yang, C.-J., & Jackson, R. B. (2011). Opportunities and barriers to pumped-hydro energy storage in the United States. *Renewable and Sustainable Energy Reviews, 15*(1), 839-844. Retrieved from https://dx.doi.org/10.1016/j.rser.2010.09.020. doi:10.1016/j.rser.2010.09.020