Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset

February 2022

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HydroWIRES

The U.S. electricity system is changing rapidly with the large-scale addition of variable renewables, and the flexible capabilities of hydropower (including pumped storage hydropower) make it well-positioned to aid in integrating these variable resources while supporting grid reliability and resilience. Recognizing these challenges and opportunities, WPTO has launched a new initiative known as HydroWIRES: Water Innovation for a Resilient Electricity System. HydroWIRES is principally focused on understanding and supporting the changing role of hydropower in the evolving U.S. electricity system. Through the HydroWIRES initiative, WPTO seeks to understand and drive utilization of the full potential of hydropower resources to contribute to electricity system reliability and resilience, now and into the future.

HydroWIRES is distinguished in its close engagement with the DOE National Laboratories. Five National Laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the DOE portfolio that add significant value to the HydroWIRES initiative.

HydroWIRES operates in conjunction with the Grid Modernization Initiative, which focuses on the development of new architectural concepts, tools, and technologies that measure, analyze, predict, protect, and control the grid of the future, and on enabling the institutional conditions that allow for quicker development and widespread adoption of these tools and technologies.

Connections with the HydroWIRES Roadmap

This report on Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset focuses primarily on addressing HydroWIRES Objective 3.2: Distinguishing Conventional Hydropower and Pumped Storage Resources for Planning Purposes.

Additional Acknowledgments

We acknowledge the contributions of our partners on this project: Zhi Zhou, Jongwon Kwon, and Kumarsinh Jhala of Argonne National Laboratory, who have assisted in developing this work and are incorporating the principles identified herein into a techno-economic analysis of dual-use energy storage that will be published separately.

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Finally, we gratefully acknowledge the leadership and effort of staff and stakeholders within the California Independent System Operator and Midcontinent Independent System Operator regions for their work in exploring the topic of dual-use energy storage and forming a solid foundation upon which this project could build.

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Executive Summary

Because the electric grid is a real-time delivery system, it must be large enough to meet the highest levels of demand and withstand any reasonably foreseeable contingencies, even if that demand only occurs for a few hours per year and those contingencies never manifest. The result is that the transmission system is much larger than what is needed under average conditions, and it has significant excess capacity most of the time.

Recognizing this, the Federal Energy Regulatory Commission (FERC) issued a policy statement in 2017 supporting the deployment of energy storage for the dual uses of regulated transmission service and competitive market service. By allowing this usage model, FERC reasoned, revenue earned through market operations when the storage asset isn't needed for transmission could be shared with customers and system costs could be reduced. This type of use is becoming increasingly relevant amid growing calls for significant new investments in the transmission system to incorporate new renewable generation.

But this approach represents a significant change in electric grid operations, which have historically separated transmission and generation functions into distinct siloes. To deploy dual-use storage, the differences between how transmission and generation systems are planned, expanded, and compensated will need to be resolved. Implementation of the policy statement creates a significant opportunity for pumped storage hydropower (PSH) facilities in particular, given that their scale is well aligned with transmission applications and that a proposed dual-use PSH facility was a key motivating factor for the policy statement.

This paper reviews the technical barriers in transmission planning practices and energy market design that prevent the realization of dual-use energy storage projects, describes the principles that a dual-use project must satisfy to meet both functions, and identifies policy options that abide by those principles. Its purpose is to objectively inform subsequent proceedings on dual-use energy storage by framing the issue and identifying options available to regional market operators, utilities, developers, regulators, policymakers, and other stakeholders as they collectively work on this complex issue. The principles identified are technologically neutral and adaptable to PSH, batteries, or any other bi-directional energy storage technology.

Where transmission assets are identified through extensive planning processes and subject to regulatory review, competitive energy and ancillary service markets are designed to create comparatively fewer barriers to entry for generation assets. Because of these disparate paths to entry, a dual-use asset would need to be first identified through a transmission plan, and then provide market services on an as-available basis.

Traditional transmission planning processes, however, create at least five barriers that prevent the identification of energy storage alternatives:

- Lack of clarity for how and when storage will be considered
- Difficulty representing storage in power flow models
- Weak links between transmission and generation planning processes
- Financial disincentive for utilities to consider lower-cost options
- Lack of regulatory review

A review of current transmission planning practices reveals that two regions have begun addressing these barriers by establishing clear processes regarding how and when storage options will be considered.

These regions took different approaches—one creating an expectation for planners to proactively identify storage alternatives and the other creating a mechanism for stakeholders to propose storage alternatives—that illustrate the options available to regional transmission planning coordinators for improving the representation of energy storage in the planning process.

Accurately valuing a dual-use storage asset in the transmission planning process also requires clarity around how the asset may participate in the market, to facilitate accurate forecasts of market revenue and how much revenue will be credited back to customers. Accounting for these credits during the planning process improves the accuracy of cost comparisons between storage and traditional infrastructure alternatives and increases the potential for identifying cost-effective storage alternatives.

Allowing an energy storage device deployed as a transmission asset to also access wholesale energy markets creates several competing priorities. Market participation creates offsetting revenue to be shared with customers, but excessive participation may also reduce the useful life of the asset and ultimately increase costs to customers if the device must be repaired or replaced ahead of schedule. A storage asset that is oversized relative to the transmission need it is meeting creates headroom to provide more market services, but also creates inequities for other market participants. A dual-use participation framework must walk a fine line that balances these competing priorities while ensuring that market participation does not jeopardize the asset's ability to serve the transmission function for which it initially selected.

Because existing policies and regulations vary across regions, developing a universal participation model would not be practical. To maximize flexibility and adaptability across multiple regions, this paper identifies the principles that a participation framework must satisfy and the options available to policymakers in satisfying them. Those principles can be summarized in three key questions that a dual-use participation model must answer:

- **When** will the asset participate in the market? Establishing boundaries for market participation, either in temporal terms or operational terms based on the storage asset's state of charge, allows the owner to make informed bids into day-ahead markets.

- **How** will the asset participate in the market? Market products and resource definitions need to recognize the unique nature of dual-use assets by allowing them to simultaneously bid into multiple services and be dispatched in real time as grid conditions require.

- **Where** will the asset recover its costs? Cost recovery mechanisms must balance the revenues earned from transmission rates and market participation to incent reasonable levels of market participation and ensure that customers realize the financial benefits of dual-use energy storage.

These principles will be incorporated into a techno-economic analysis that will quantify the economic benefits of dual-use energy storage to the grid and to customers, using a theoretical PSH facility. Project partners at Argonne National Laboratory will publish that analysis in a subsequent report.

Acronyms and Abbreviations

CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Planning
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
PSH	Pumped Storage Hydropower
RTO	Regional Transmission Organization
SATA	Storage as a Transmission Asset
SATOA	Storage as a Transmission-Only Asset
SERTP	Southeastern Region Transmission Planning
SPP	Southwest Power Pool
TAC	Transmission Access Charge
TPP	Transmission Planning Process
TRR	Transmission Revenue Requirement
WECC	Western Electricity Coordinating Council

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1.0 Introduction and Background

In 2017, the Federal Energy Regulatory Commission (FERC) issued a policy statement expressing support for the deployment of energy storage assets that could provide two distinct types of service to the electric grid: one as a regulated transmission asset and the other as a competitive energy market asset (FERC 2017). By enabling that type of use, FERC reasoned, market revenues earned by the storage device when not needed for transmission service could be shared with customers to offset its costs, thereby reducing overall system costs. FERC's policy statement invited—but did not require—the regional energy market operators that it regulates to propose policies to enable this type of asset, known as dual-use energy storage.

Efforts to implement FERC's policy statement quickly revealed numerous regulatory barriers, and no regional market has yet implemented the changes necessary to enable dual-use energy storage. However, the policy statement's vision of energy storage contributing to a lower cost, increasingly flexible transmission grid is taking on new significance amid aggressive state requirements and federal goals to decarbonize the electric grid, as achieving that objective will likely require significant new investments in transmission infrastructure (Caspary, Goggin, Gramlich, and Schneider 2021; Coy 2020; Walton 2020).

The objective of this paper is not to advocate for specific policies or changes, but rather to clearly explain the barriers that impede the deployment of dual-use energy storage, the key principles that a dual-use participation model must satisfy, and policy options for satisfying those principles. By taking a flexible approach, this paper may be of use for regional market operators, utility transmission planners, federal and state regulators, energy storage developers, and other market stakeholders in future proceedings to implement FERC's policy statement in accordance with each region's unique circumstances.

From a technological standpoint, any energy storage technology would be capable of serving as a transmission or dual-use asset, subject to project needs and technological characteristics. As will be discussed, the first two projects deploying storage as a transmission-only asset in the U.S. both used batteries. The principles and policy options that will be presented are technologically agnostic, though as will be explained, they may need to be adapted to certain technologies. This paper focuses on pumped storage hydropower (PSH) for several reasons:

- **Scale:** PSH facilities tend to be large in scale; the 39 existing U.S. facilities have an average nameplate capacity of 561 megawatts (MW), while eight are larger than 1,000 MW, and the largest – the Bath County facility in Virginia – is 2,862 MW (EIA 2021). This scale allows PSH to inject or withdraw significant amounts of power, making it a candidate for high-power transmission applications.

- **Cost Structure:** PSH requires significant capital outlays but provides long-duration storage and has a useful life of 40 years or more. Because PSH provides longer duration storage, it is relatively more expensive when compared to battery energy storage on a capacity basis and relatively less expensive when compared on an energy basis (Mongird et al. 2020). Table 1 illustrates this relationship.

Table 1: Capacity and Energy Cost Comparison

	Pumped Storage Hydro	Lithium-Ion Battery
Duration	10 Hours	4 Hours
Useful Life	40 Years	10 Years
Capacity Cost ($/kW)	$2,623	$1,541
Energy Cost ($/kWh)	$262	$385

Mongird et al. 2020

Transmission assets, which require significant capital expense and offer long useful lives, have a similar cost structure to PSH.

- **Construction Time:** Due to a complicated process of permitting and constructing the necessary facilities, PSH projects can take between 10 and 14 years to develop (Meier et al. 2010). Transmission projects face a similarly long process of permitting and developing that can last for several years (Eto 2016). These similar development timeframes suggest that PSH may compare more favorably within transmission planning processes that, because of the lead time for developing a transmission project, are already conducting a long-term evaluation of grid needs.

Given these characteristics, transmission and dual-use applications likely represent a significant potential market for PSH assets. From a planning perspective, a PSH facility's capital requirements and development cycle are more closely aligned with those of a transmission line than those of a generator. As will be discussed, FERC's policy statement was prompted in large part by a developer's proposal to build a dual-use PSH project. As will also be discussed, implementation of the policy statement will require improved representation of energy storage technologies in transmission planning processes and development of energy market products that allow storage assets to move between transmission and generation functions. Given PSH's similarities with transmission assets and demonstrated developer interest in building PSH as a dual-use asset, implementation of the policy statement will create new competitive pathways for PSH assets to be selected and built.

The participation model identified in this paper will be used in a techno-economic analysis by project partners at Argonne National Laboratory that will be presented in a subsequent paper. While that analysis will approach the question of dual-use energy storage through the lens of PSH for the reasons identified above, the participation model itself is technology neutral and applicable to all forms of energy storage. Similarly, while this project focuses on enabling dual-use energy storage within the context of the regional markets subject to FERC's policy statement, the principles identified may be of use to utilities operating outside those markets as they plan their transmission system and evaluate opportunities for multifunction energy storage investments.

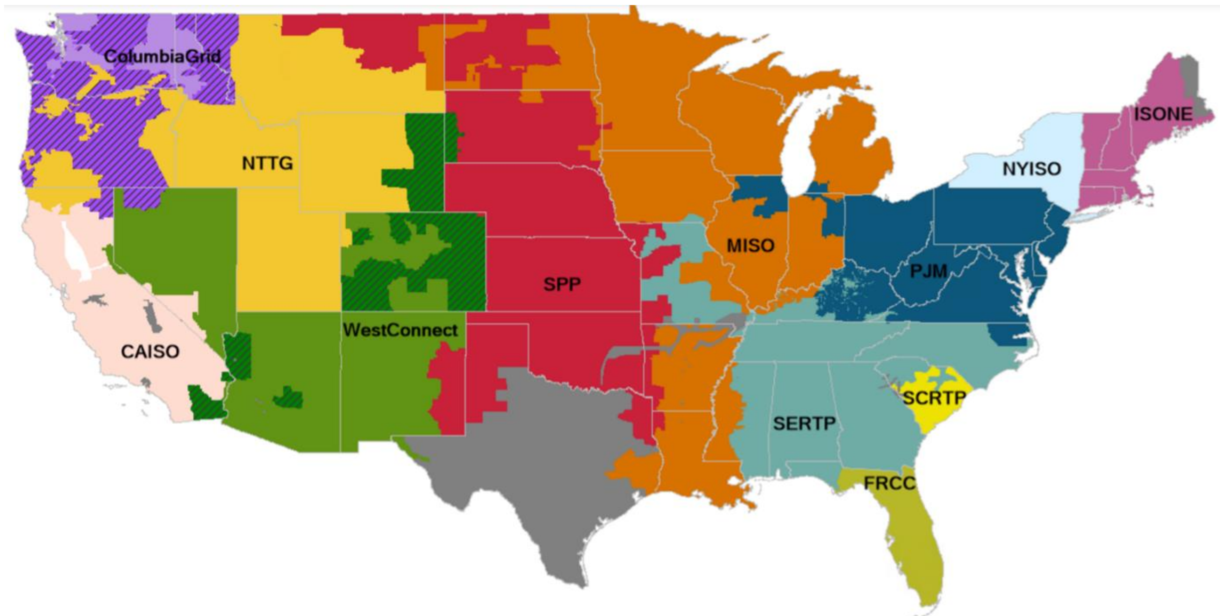
The remainder of this section will provide a more detailed summary of the technology, regulatory, and policy principles behind the concept of dual-use energy storage. Section 2 focuses on the transmission side and identifies the barriers in regional transmission planning processes (TPPs) that impede the selection of storage alternatives. Section 3 focuses on market operations and discusses the principles that must be met when allowing energy storage deployed as a transmission asset to also access wholesale markets. Section 4 presents the dual-use energy storage participation framework identified by the authors. Finally, Section 5 summarizes the paper and introduces the work that will be presented in the techno-economic analysis paper.

1.1 Regulatory Background

Energy regulation in the United States is rooted in federalism, meaning that some grid functions are subject to federal regulators and some to state regulators. Similarly, some grid assets recover their costs through fixed rates set by regulators and others through competitive rates set by market forces. These structures have important implications for dual-use energy storage.

Electric transmission infrastructure that is connected (either directly or indirectly) across state lines is subject to federal regulation through FERC, which asserts its jurisdiction over the transmission system in two ways: system planning and ratemaking. On the planning side, FERC has issued a pair of orders requiring transmission owners to engage in transparent system planning processes (Order 890) and to coordinate transmission system planning on a regional basis (Order 1000). Figure 1 illustrates the planning regions formed in response to Order 1000.

On the ratemaking side, FERC issued Order 888 in 1996 to require all transmission owners to allow other parties access to their transmission system on an equal basis at cost-based rates set by FERC, which are calculated based on the cost of building and operating the system. Where a transmission owner participates in a wholesale regional market operated by an independent system operator (ISO) or a regional transmission organization (RTO), cost recovery comes through FERC-established rates collected by the ISO or RTO on behalf of transmission owners. In the case of a vertically integrated utility, which owns and operates its own generation, transmission, and distribution systems, state regulators set rates for the transmission system, and its costs are recovered from the utility's customers (minus the revenue that the utility earns from usage of its system by other parties at FERC rates). In either case, transmission owners almost universally recover their investments through fixed, cost-based rates set by regulators.[1]



FERC[2]

Figure 1: Map of FERC Order 1000 Transmission Planning Regions

Electric generators, on the other hand, are planned and compensated through different mechanisms, depending on the regulatory structure under which they operate. In a vertically integrated utility, the utility identifies resource needs through planning processes subject to review by state regulators and then recovers the costs of its investments through fixed rates set by state regulators and then assessed on all customers.

Specific processes vary by region, but in general ISOs and RTOs use competitive market processes to procure new generation resources, which are then compensated through market-based rates. These differences in how transmission and generation assets are planned and compensated are most pronounced in an ISO/RTO, where regulated planning and cost-based rates for transmission assets create a mismatch

[1] Under limited circumstances, FERC has authorized merchant (non-utility) transmission owners to negotiate with customers to set rates for usage of their facilities.

[2] The ColumbiaGrid (purple) and Northern Tier Transmission Group (yellow) regions merged in 2020 to create a single region known as NorthernGrid.

with competitive planning and market-based rates for generation assets that must be reconciled to enable dual-use storage.

1.2 Technology Background

Energy storage technologies are uniquely capable of providing a wide range of services to the electric grid. Because it can either absorb or inject electricity and can quickly adapt its input or output based on changing grid conditions, energy storage can increase grid flexibility. And because storage technologies can be as small as a 5-kilowatt (kW) battery hanging on the wall of a garage or as large as a 2,800 MW PSH facility, they can be scaled and sited based on specific grid needs. This section briefly summarizes the grid services that energy storage can provide as a transmission asset and as a generation asset.

Figure 2: Cross Section of Overhead Electric Transmission Lines

1.2.1 Transmission Benefits of Storage

Building an electric transmission line requires balancing several conflicting goals: materials must have good electrical conductivity; they must be light enough to hang from towers but sturdy enough to withstand the elements; and they must be abundant enough to allow for largescale usage at a reasonable price. In balancing these needs, most transmission lines in the United States are built from some combination of aluminum and steel; aluminum to carry the electric current and steel (or some other rigid material) to provide a relatively low-cost means of structural support, as shown in Figure 2.

However, because aluminum is not a perfect conductor, it heats up as electricity moves through it. In addition to causing some of the transmitted electricity to be lost as heat, this phenomenon causes the metals to expand as they heat up, which causes transmission lines to sag. If a transmission line sags enough to come into direct contact with other lines, structures, vegetation, or the ground, it can cause significant damage to both the line and the objects with which it comes into contact.

To account for that risk, a transmission line's thermal rating—the temperature at which it can safely operate—is a key component of safety and reliability standards for electric transmission systems. Thermal rating depends on how much energy is moving through a line as well as ambient temperature, and the specific thermal rating of a line may vary as those contributing factors fluctuate (Karimi, Musilek, and Knight 2018).

As will be discussed in greater detail in Section 2, reliability standards require transmission planners to study contingency scenarios that would alter or disrupt power flows across the transmission system; some of these scenarios may result in particular lines exceeding their thermal rating or some customers losing power. In these scenarios, energy storage can be deployed as a transmission system component to regulate power flows or preserve service to customers, as demonstrated in the case study on the following page. In addition to these reactionary services, energy storage may also support the transmission system in more proactive ways, such as providing voltage support (FERC 2017).

From an investment standpoint, energy storage can also be an effective means of managing risk by breaking up large investments into smaller, more modular components. When dealing with uncertain

> **Case Study: Storage as Transmission**
>
> In 2019, MISO identified a scenario in which an outage on a particular transmission line could cause a cascading series of outages that would cut off electric service to the city of Waupaca, WI.
>
> MISO identified two options for preventing this scenario: build an additional circuit to add redundancy in the area or add a battery that, coupled with other local upgrades, could preserve service in Waupaca in the event of the line outage and prevent it from cascading.
>
> The battery was found to be the more cost-effective option ($12.24 million compared to $13.07 million for the additional circuit). MISO selected the battery option, which is expected to be in service in December 2021 (MISO 2019).

futures and the potential for stranded investments if system needs change, a battery asset with a useful life of about 10 years represents a smaller, less risky investment than a transmission line with a useful life of 40 or more years. Furthermore, if there is a major change in system needs and the asset is no longer needed for transmission, a storage system can be repurposed to support the generation fleet, while the transmission line has no other options. A PSH facility may not have the modularity benefit when compared to a transmission asset, but would reduce risk through its flexibility to transition to other uses if system needs change.

1.2.2 Generation Benefits of Energy Storage

While energy storage cannot create electricity, its ability to shape the output of electric generators allows it to provide several valuable grid services, particularly as the share of generation coming from variable renewable resources grows on the grid. By absorbing energy during periods of abundant generation and re-injecting that energy into the grid during high-demand periods when generation resources are scarce, energy storage may contribute toward capacity needs and reduce the requirement for additional, high-cost peak generating units.

The ability of energy storage to quickly respond to changing grid conditions also makes it an ideal candidate for providing the ancillary services that grid operators need to keep the grid in balance. Because grid stability requires supply (generation) and demand (load) to be kept in constant balance, grid operators depend on resources that have been set aside to provide ancillary services by quickly adjusting their supply or demand in response to moment-to-moment changes in generation and load or to an unplanned generator outage. Because energy storage technologies can respond to those changing conditions within seconds or minutes, and because they can absorb power in addition to injecting it, they are uniquely adept at providing ancillary services.

Recognizing these capabilities, FERC issued Order 841 in 2018, which required wholesale energy market operators to design products and rates that account for the technical characteristics of energy storage. By creating clear processes for energy storage to participate in energy markets, Order 841 has a profound impact on the viability of dual-use energy storage.

1.3 Policy Background

Since at least 2005, federal policymakers and regulators have enabled and encouraged the use of energy storage in transmission applications. In that year, Congress defined energy storage in the Energy Policy Act of 2005 as one of several "advanced transmission technologies," which are transmission alternatives that "increase the capacity, efficiency, or reliability of an existing or new transmission facility."[1]

[1] Energy Policy Act of 2005. Available at https://www.congress.gov/bill/109th-congress/house-bill/6.

In 2007, FERC adopted Order 890, which requires transmission owners to conduct transparent planning processes that are open to stakeholder participation. In preparing those plans, transmission owners were directed to communicate, but not necessarily coordinate, with neighboring transmission owners. The order also directed planners to consider non-transmission alternatives if requested by stakeholders and to define how stakeholders could propose such alternatives.

FERC followed that order in 2011 with Order 1000, which directed transmission owners to engage in coordinated transmission planning on a regional basis and develop principles for assigning the costs of transmission system infrastructure among different customers, subject to six general principles.

Individual transmission owners remain responsible for planning their transmission systems, as established in Order 890. But Order 1000 created the role of a regional planning coordinator, which is responsible for convening transmission owners from across the region and managing a coordinated planning effort. In deregulated markets, the ISO/RTO took on that responsibility, while vertically integrated utilities formed several regional coalitions to manage their processes.

Order 1000 allows significant flexibility for how regional and individual plans interact. As will be discussed in Section 2, some regions allow utilities to conduct their planning process first and then use those plans as an input to the regional process, while other regions have an integrated approach in which the regional and individual plans are done simultaneously.

Order 1000 contemplates three basic types of transmission projects that regional plans should assess:

1. **Reliability**: A project necessary to meet a reliability standard, may be regional (located within and benefitting a single region) or interregional (located in and/or benefitting multiple regions).
2. **Economic**: A project that is not necessary from a reliability standpoint but has been demonstrated to reduce congestion, thereby reducing overall system operating costs in the region.
3. **Public Policy**: A project necessary for compliance with a state or local policy, such as interconnecting a new resource needed to meet a state renewable portfolio standard, but not driven by an identified reliability need.

Order 1000 preserved the role of non-transmission assets defined in Order 890; that is planners are required to indicate at what point in the process stakeholders could propose non-transmission alternatives and to consider those alternatives on a comparative basis for all project types.

When establishing cost allocation methods for the various types of projects, Order 1000 indicated that regions can come up with different methods for different types of projects, provided that those methods are independently consistent with the principles of cost allocation identified in the order.

1.4 FERC's Policy Statement on Dual-Use Energy Storage

FERC's next landmark action on energy storage as a transmission asset came in 2017, when the commission issued a policy statement to clarify its views on the topic after a pair of similar, high-profile cases had different outcomes.

In the first case, initially filed in 2005, developer Nevada Hydro proposed a 500 MW PSH facility in Southern California. Nevada Hydro requested a declaratory order from FERC recognizing the project as a transmission asset eligible for regulated rate recovery through the California Independent System Operator's (CAISO) transmission tariff, arguing that such treatment would be consistent with the Energy Policy Act of 2005's designation of energy storage as an advanced transmission technology. However, Nevada Hydro proposed to give full operational control of the facility to CAISO and have CAISO operate it to provide transmission or generation services at the grid operator's discretion (FERC 2008).

After a lengthy proceeding that included a procedural break while CAISO conducted a FERC-ordered stakeholder initiative to explore the implications of Nevada Hydro's proposal, FERC ruled that the PSH facility was not eligible for rate treatment as a transmission asset. FERC's rejection was rooted in two conclusions: that the proposal did not clearly establish how the PSH facility would be operated in a distinct manner from existing PSH facilities that operate as generators, and that turning over operational control of the facility to CAISO would jeopardize the grid operator's independence (*id.*).

Informed by the outcome of the Nevada Hydro proceeding, developer Western Grid proposed a different approach to using storage as a transmission asset in 2009. Western Grid's proposal consisted of deploying several sodium sulfur batteries at various locations within CAISO, ranging in size from 10 to 50 MW. The proposal stated that the batteries would be used exclusively on the transmission system to provide voltage support and relieve thermal overloading. Western Grid would own and operate the devices at CAISO's direction as a registered transmission provider, and the batteries would not participate in CAISO's energy markets. Western Grid would purchase retail energy to charge the devices and receive retail compensation when discharging them, with any net proceeds returned to customers (FERC 2010).

FERC granted Western Grid's request for a declaratory order, determining that Western Grid had clearly demonstrated that the assets would be operated in support of the transmission system and that CAISO would not be required play an active role in managing them (*id.).*

In both cases, CAISO and other parties argued that it was premature for FERC to make any determinations on proposed projects before those projects had been analyzed and selected in resource planning processes operated by the State of California and CAISO. FERC agreed that the projects would ultimately need to be selected on their own merits in a planning process, but indicated in the Western Grid order that determining whether a proposed storage asset would qualify for transmission rate treatment would accurately inform planning processes about the costs and operation of that asset (*id.*). Table 2 summarizes the key differences between the Nevada Hydro and Western Grid proposals:

Table 2: Summary of Nevada Hydro and Western Grid FERC Applications

	Nevada Hydro	**Western Grid**
Technology	Pumped Storage Hydro	Sodium Sulfur Batteries
Operator	CAISO	Western Grid
Proposed Grid Services	Any (Transmission and Generation)	Voltage Support, Thermal Management (Transmission Only)
FERC Outcome	Rejected	Approved

In the 2017 policy statement, FERC repeated its rationale for rejecting the Nevada Hydro petition and approving the Western Grid petition. Commissioners then went on to clarify an important point: While the Western Grid petition was approved as a transmission-only project, FERC conceptually supported Nevada Hydro's idea of using storage for both regulated transmission and competitive market purposes, given the potential for market revenues to be shared with customers in a way that would reduce system costs (FERC 2017). However, commissioners explained, such projects must adhere to three principles:

1. **Double recovery of the asset's costs must be avoided**. FERC's overriding objective in the policy statement was to increase the efficiency of the grid and reduce its cost by maximizing the use of energy storage. Allowing an asset owner to recover their full investment through cost-based transmission rates and then additional revenue in the market would not accomplish that goal, so FERC indicated that dual-use energy storage mechanisms would need to balance the two revenue streams to ensure that customers do not overpay for the asset.
2. **Adverse market impacts of dual-use assets must be minimized**. In the proceeding that led to the policy statement, several participants expressed concern that energy storage selected for transmission purposes would not have to pay for its interconnection costs and, given its ability to recover most of its costs from regulated services, would not enter the market with the same cost structure as other market assets. Stakeholders worried that these unfair advantages could lead the dual-use asset to submit artificially low bids that suppress prices for other market participants. FERC acknowledged this concern but indicated that mechanisms to prevent double-recovery of costs would likely balance out any advantages that dual-use storage assets might have.
3. **ISO/RTO independence must be maintained.** Objective and fair operation of regional transmission systems and wholesale markets require ISOs and RTOs to be independent entities, FERC stated. Therefore, the policy statement indicated that the ISO/RTO should only have operational control of a dual-use storage asset when it is being used for transmission functions, and control should revert to the asset owner when it is being used for market functions. In practical terms, this means that the asset is operated by the grid operator as needed in transmission mode, and then dispatched based on bids submitted by the asset owner in market mode.

A policy statement is a nonbinding document, so market operators were not obligated to act on it. Section 3 summarizes proceedings in the two regions that voluntarily responded to the policy statement.

1.5 Storage as Transmission vs. Storage in Place of Transmission

There are two ways in which a need for energy storage could manifest in a transmission plan: <u>as</u> a transmission asset or <u>in place of</u> a transmission asset.

Within the U.S. energy regulatory structure, there is a significant difference between a regulated storage asset that provides service to the transmission system and a competitive storage asset that provides service to energy markets in a manner that reduces or eliminates the need for transmission infrastructure. CAISO's 2018 Transmission Plan provides contrasting case studies that illustrate the difference.

1.5.1 Storage as Transmission: Dinuba, CA

Dinuba is a small town in central California served by a 70 kilovolt (kV) transmission system. In its 2010 Transmission Plan, CAISO identified a contingency scenario in which an outage on a nearby, larger transmission line would overload the line serving Dinuba. The 2010 plan called for several minor investments in the local system to temporarily manage the contingency, with a future rebuild of the Dinuba line to increase its thermal rating (CAISO 2018a).

In the 2018 Transmission Plan, CAISO compared the rebuild option to an alternative plan that would deploy a battery at the Dinuba substation to absorb and manage excess flows during the contingency. CAISO selected the battery alternative after determining that it could be deployed for $14 million, while the line rebuild would cost $16 million (*id*).

Figure 3 illustrates how the energy storage option will protect the existing Dinuba system during a contingency event by regulating power flows and preventing thermal overloading, making it a transmission asset subject to cost-based rates.

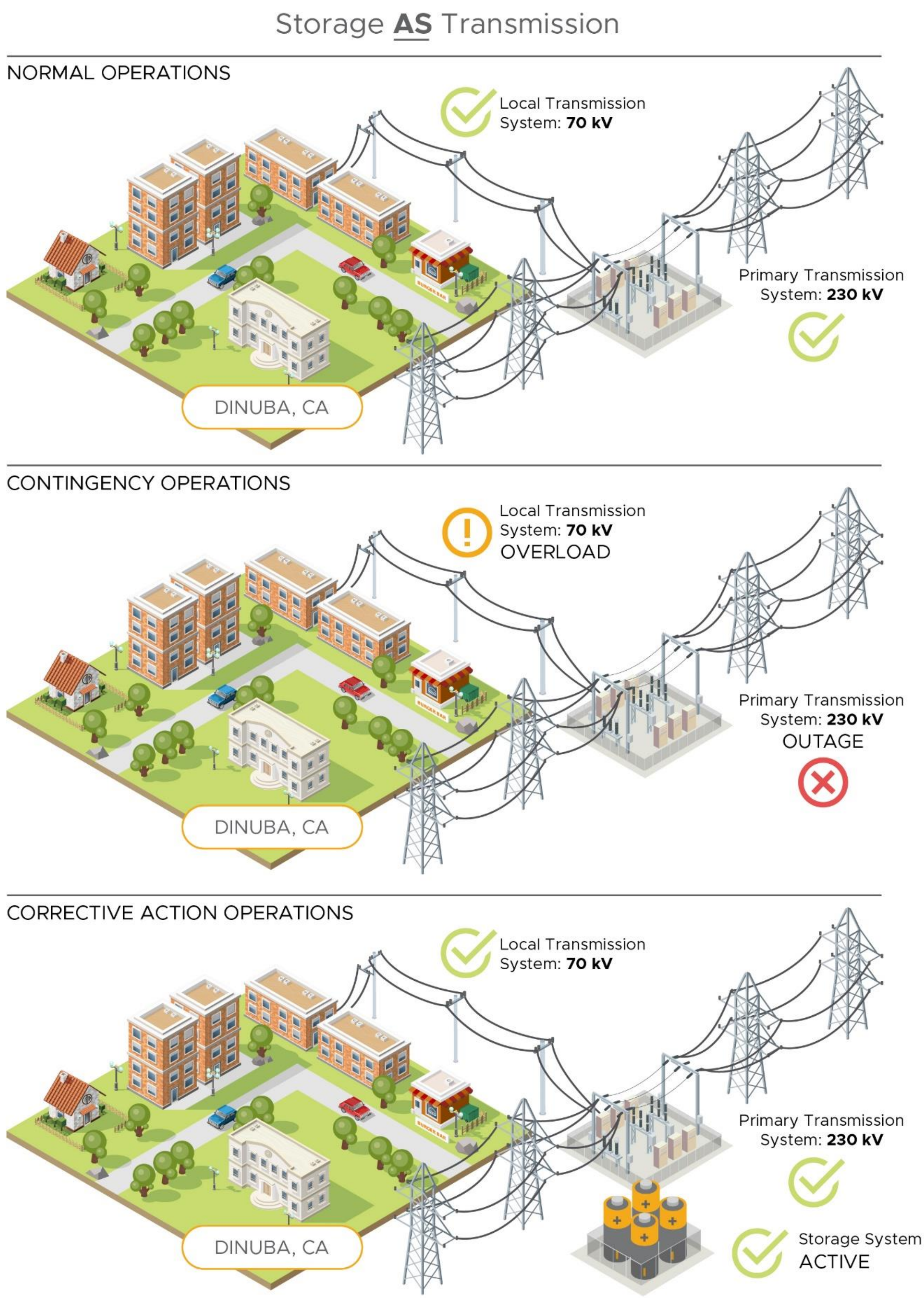


Figure 3: Storage as Transmission in Dinuba, CA

1.5.2 Storage in Place of Transmission: Oakland, CA

Elsewhere in their 2018 Transmission Plan, CAISO planners faced the challenge of preserving reliable service in the Oakland area after determining that the imminent retirement of an aging, 165 MW peaker plant in the downtown area would create contingency scenarios in which the transmission lines serving the city would not have sufficient capacity to meet local demand.

CAISO considered four proposals, including a major overhaul of existing transmission lines in the area, construction of a larger new line, and placing a 200 MW generator in the area. Estimated costs for those alternatives were between $367 million and $574 million. But the successful proposal came jointly from the transmission-owning utility in the area and the community choice aggregator that procures generation resources to serve the Oakland area: a $102 million initiative to conduct minor upgrades on the existing lines, then site energy storage and distributed solar within the Oakland area to preserve reliable service during a contingency event (CAISO 2018a).

Figure 4 illustrates how the locally sited energy storage systems would act as generation assets within CAISO markets to maintain service in a contingency event. While the presence of the storage reduces the transmission infrastructure investments necessary to ensure reliable service, the storage would not directly affect power flows or transmission system operations, and would recover its costs by participating in energy markets. It is therefore a competitive asset subject to market-based rates.

As Figures 3 and 4 demonstrate, energy storage can benefit the grid in multiple ways. But regulatory structures affect how those benefits are realized and compensated: either fixed operations and cost recovery as a transmission asset, or market-driven operations and cost recovery as a generation asset. These disparate regulatory structures create incompatibility in how each function plans for its needs, operates its assets, and recovers the costs of those assets. That incompatibility creates a formidable barrier for dual-use energy storage technologies, one that FERC’s policy statement encouraged grid operators to reduce.

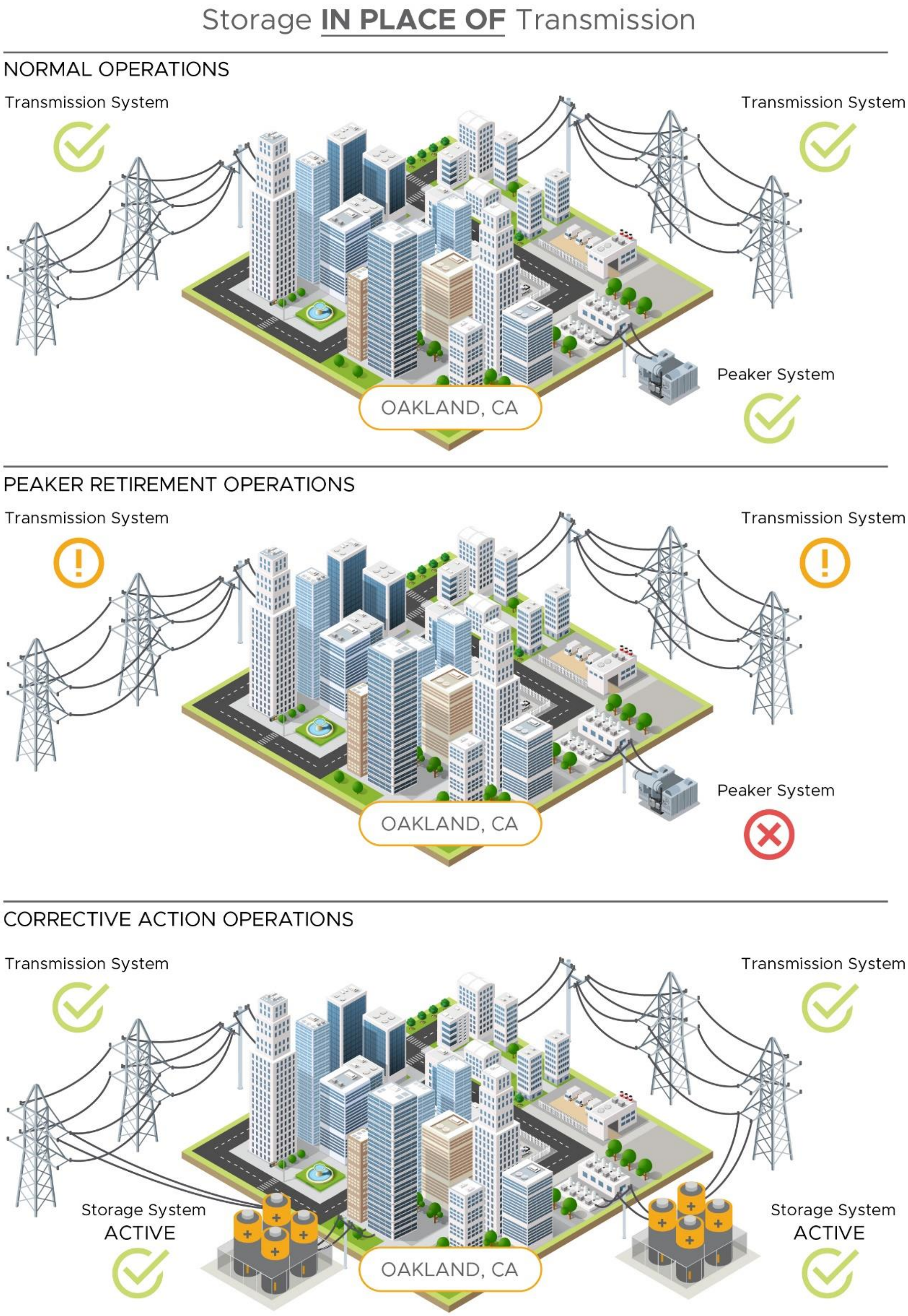


Figure 4: Storage in Place of Transmission in Oakland, CA

2.0 Energy Storage and Transmission System Planning

Near the end of the policy statement, FERC makes an understated but crucial point:

> *We also provide guidance that, when the circumstances leading to the need for the service compensated through cost-based rates arise, RTO/ISO dispatch of the electric storage resource to address that need should receive priority over the electric storage resource's provision of market-based rate services. Performance penalties could be imposed on the electric storage resource owner or operator for failure to perform at these times (FERC 2017).*

This guidance forms a key principle of this project: that the reliability function performed by a dual-use storage resource in its transmission role always takes priority, and that market services may only be provided in a manner that does not compromise the asset's ability to meet its transmission obligations. Grid operators are subject to dozens of mandatory reliability standards. Failure to meet them subjects the operator to severe fines, may expose customers to service interruptions, and may damage grid infrastructure.

As explained in Section 1, transmission investments are identified through extensive planning processes, then subject to regulatory review and approval before they can be eligible for cost-based rate recovery. Energy and ancillary service markets do not share those hurdles; minimal barriers to entry are a key element of a competitive market.

Because of this disparity in how transmission and generation assets enter service in an ISO/RTO, a dual-use energy storage asset would logically need to be identified as a transmission asset first, and then provide market services on an as-available basis. To assume that an energy storage device could enter the grid as a generation asset and then provide transmission services as well would be inconsistent with the way the transmission system is planned and expanded. Requiring dual-use energy storage assets to first be identified through a TPP is consistent with regulatory structures and reinforces the primacy of reliability functions over market functions. In its proceeding to consider implementation of the policy statement, CAISO determined that energy storage could only be a dual-use asset if it were initially identified and constructed as a transmission asset (CAISO 2018c).

This section will summarize the reliability standards that grid operators must meet, the transmission planning practices they use to ensure compliance with those standards, and the barriers that those planning practices create for energy storage.

2.1 Reliability Standards Governing Transmission Planning

In the Energy Policy Act of 2005, Congress created a new entity, an Electricity Reliability Organization, which would be a single organization responsible for developing and enforcing industrywide standards to ensure electric grid reliability, and directed FERC to establish the organization. In 2006, FERC selected the North American Electric Reliability Corporation (NERC) to fulfill that role. Through consensus-based processes, NERC has since led the development of almost 100 mandatory reliability standards and more than 400 voluntary standards.

From a transmission planning perspective, NERC standards serve two primary purposes. First, they provide a practical framework for transmission planning. While Congress and FERC have collectively developed policies requiring transparent, regionally coordinated transmission planning practices that consider a wide range of technology options, NERC standards establish the metrics that those plans must meet to ensure a reliable electric grid and identify the tools, processes, and plan structure that system planners should utilize.

Second, NERC standards ensure consistent industry practices in regions outside of traditional FERC jurisdiction. Because its footprint is located entirely within the state of Texas and it has no interconnections with any other U.S. regions, the Electric Reliability Council of Texas region is not subject to FERC rate jurisdiction, which is rooted in the interstate transmission of electricity. The Texas region is, however, subject to NERC standards. Canada has also agreed to abide by NERC standards, which ensures that energy transacted between the two countries is done on compatible systems meeting the same reliability requirements.

NERC's regulations governing transmission system planning are found in Standard TPL-001-5, *Transmission System Planning Performance Requirements* (NERC 2020), which places eight specific requirements on transmission planners.

1. **Modeling**: Planners must maintain robust models of their respective transmission systems capable of performing the required modeling exercises.
2. **Annual planning**: Planners must conduct annual studies that include near-term and long-term sensitivity analyses and a corrective action plan for remedying any identified shortcomings.
3. **Steady-state analysis**: Plans must analyze the system's ability to regain normal operation after minor disturbances and under multiple contingencies.
4. **Stability analysis**: Plans must analyze the system's ability to manage grid fluctuations arising from major disturbances and regain normal operations under multiple contingencies.
5. **Voltage requirements**: Planners shall establish standards to ensure proper voltage levels are maintained on the system.
6. **Instability criteria**: Planners shall develop criteria by which system instability events will be identified.
7. **Internal coordination**: The planning coordinator shall ensure that all participating entities with planning responsibilities understand their individual and joint responsibilities.
8. **External coordination**: Planners shall share studies and other relevant information with planners from other regions (NERC 2020).[1]

NERC Standard TPL-001-5 contains several pages of detailed contingencies that TPPs must consider. These contingency scenarios are referred to as "n-1" scenarios, in which "n" represents the grid in its normal operating state and "-1" represents some element of the grid that is out of service, such as a power plant or a transmission line. Other contingency analyses may consider an "n-1-1" scenario, in which one outage is followed by another, or an "n-2" scenario, in which two outages happen simultaneously.

Where a contingency analysis reveals that reliability criteria (also set forth in the standard) will not be met, planners must develop a corrective action plan for ensuring system reliability under that contingency. The standard also requires the planning process to include public stakeholder input.

While NERC standards do not explicitly address the role of non-transmission alternatives in the planning process, they do grant wide latitude to system planners in identifying corrective actions. NERC's required

[1] Mandatory NERC standards are subject to FERC approval; FERC approved TPL-001-5 in January 2020, replacing the previous standard (TPL-001-4). The new standard requires additional reliability analyses of protection systems and potential long-term equipment outages, though those requirements will not be enforced until January 2023.

contingency analyses therefore are the primary entry point for energy storage in transmission planning. Energy storage cannot move electricity through space like a transmission line, but because it can move electricity through time, it can be a viable alternative for managing power flows or preserving service to customers in the event of an outage, which are the services required in many contingency scenarios. Used in this manner, energy storage can enhance and protect existing transmission infrastructure, giving it greater flexibility and extending its useful life while deferring or eliminating the need for additional infrastructure.

2.2 Barriers to Energy Storage in the Transmission Planning Process

Congress designated energy storage as a viable transmission asset in 2005; FERC reinforced the notion of non-transmission alternatives in 2007 (Order 890) and again in 2011 (Order 1000). However, it was not until 2018 that the first regional transmission plan selected energy storage, and only one other region has followed.

To develop an inventory of the barriers that have impeded the inclusion of energy storage in regional transmission plans, the research team conducted a thorough review of the planning processes adopted in each of the Order 1000 planning regions. Documents included in this review were transmission planning tariffs, ISO/RTO business practice manuals, and recently completed transmission plans. A summary of each region's planning process and the role of energy storage in those processes can be found in Appendix A.

Through that review, the research team identified five barriers to energy storage in transmission planning:

- Lack of clarity for how and when storage will be considered
- Difficulty representing storage in power flow models
- Weak links between transmission and generation planning processes
- Financial disincentive for utilities to consider lower-cost options
- Lack of regulatory review

Lack of clarity for how and when storage alternatives will be considered. Orders 890 and 1000 direct transmission planners to consider energy storage and other non-transmission alternatives, but only at the request of stakeholders. While the orders require planners to indicate how and when stakeholders may make those requests, most regions do not appear to have developed that guidance. Several of the planning regions' transmission planning business practice manuals do not specifically identify a process for stakeholders to propose non-transmission alternatives. Similarly, recent transmission plans prepared in most regions make no mention of considering energy storage or other non-transmission alternatives.

Part of the challenge is uneven implementation of Order 1000's regional planning requirements. In some regions, such as PJM and CAISO, the entire TPP is conducted on a regional basis. In others, such as MISO and the Southwest Power Pool (SPP), individual utilities prepare their own transmission plans, which are then used as inputs for a coordinated regional planning process. In vertically integrated regions, the process is much more utility-centric, and regional coordination appears to be limited. These different approaches to regional coordination create an uneven environment for would-be proposers of storage alternatives. Where one region may require engagement at the regional level from the beginning, another may require engagement in individual utility planning processes that are done independently and prior to the regional coordination function.

Difficulty representing storage in power flow models. Planning the transmission system and conducting NERC-required contingency analyses requires a detailed and granular model of the system. These power flow models evaluate the transmission system's ability to match generation to load in real time, even when there are interruptions. This is a complicated process consisting of matching numerous generation resources to loads, subject to the transmission system's characteristics and constraints. Where the objective of power flow models is to match generation to load in real time, the introduction of energy storage allows power flows to be redirected in one period to provide benefits to the system in a later period. This temporal component, while potentially beneficial, introduces another complicated variable to power flow modeling (Maffei et al. 2014).

Weak links between transmission and generation planning processes. As regional planning coordinators, ISOs and RTOs have direct authority over transmission planning and procurement processes. Generation planning and procurement activities, however, are either market-driven or overseen by state regulators, depending on the region. This disconnect means that if a transmission plan identifies an opportunity for energy storage to be deployed in place of transmission, there is no clear pathway for the asset to be identified and acquired in generation planning and procurement processes. This lack of certainty that the resource needs identified in place of a transmission solution would be met through independent resource acquisition processes may discourage transmission planners from giving serious consideration to storage alternatives deployed in place of transmission.

In California, where both the entity responsible for overseeing transmission planning (CAISO) and the entity responsible for overseeing generation planning (the California Public Utilities Commission or CPUC) are agencies of the same state, coordination is more readily achieved. In its most recent transmission plan, CAISO indicated that close coordination with CPUC "ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the storage resource to participate broadly in providing value to the market" (CAISO 2020). However, other ISOs and RTOs, particularly those covering multiple states, do not appear to have the same level of coordination available to them through market structures or generation planning processes.

Financial disincentives for utilities to consider storage alternatives. While not directly addressed in any of the documents reviewed, market and regulatory structures create strong financial disincentives for utilities to consider energy storage and other non-transmission alternatives, which bears mentioning in this context. Transmission lines can be an attractive investment; cost-based rates mean that asset owners receive not only guaranteed recovery of their costs, but also a guaranteed return on their sizeable investment. For example, after recently revising its process for determining the return on equity that transmission owners can earn on their investments, FERC approved a return of 10.02 percent for MISO transmission owners, with the potential for various FERC-approved transmission incentives to increase it to 12.62 percent (FERC 2020a).

If a lower-cost energy storage alternative is selected as a transmission asset, it means less investment and less return for the asset owner. While this may be a minor financial disincentive when comparing two assets with similar capital requirements and guaranteed cost recovery, it can be a powerful disincentive if storage alternatives are subject to competitive procurement or if ISO rules prohibit utility ownership of generation assets.

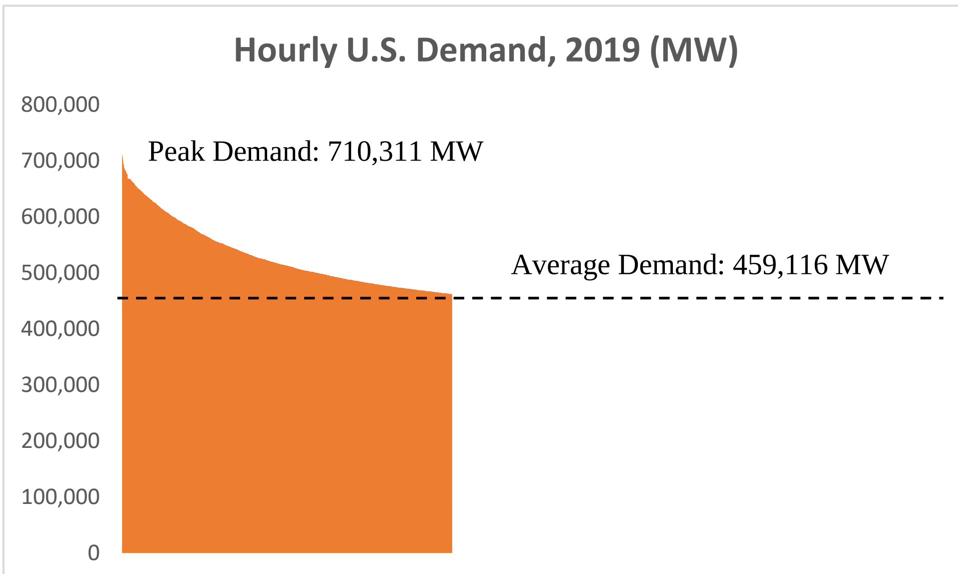
As alluded to in the MISO example above, FERC provides incentives in the form of higher investment returns to transmission owners who develop projects in a way that advances certain federal priorities. FERC proposed several new and increased transmission incentives in 2020, including a 100 basis points (1 percentage point) incentive for technologies that "enhance reliability, efficiency, capacity, and improve the operation of new or existing facilities" (FERC 2020b). But the proposal was not clear on whether energy storage technologies would be eligible, and FERC has not yet made a final determination.

Lack of regulatory review. Many states require utilities to regularly file plans that present a thorough analysis of the utility's future electric system needs and its plan for meeting them. States that require such plans conduct formal reviews in which they may approve or reject the plan, or simply acknowledge that the utility has met its filing requirements. These reviews give state regulators the opportunity to ensure that the utility has complied with the state's planning directives and provide feedback to the utility that can shape future resource plans. Through iterative reviews across multiple planning cycles, regulators, utilities, and stakeholders can collaboratively develop the practical tools and processes to implement complex policy directives.

Despite issuing several orders and policy statements over the years to guide utility and regional transmission planning processes, FERC does not conduct formal reviews of transmission plans to verify that its guidance is being followed. Absent the iteration that comes with formal review processes, many of the complex objectives identified in those orders and policy statements have not been worked out in practical terms. Some commissioners identified the resulting deficiencies in current regional transmission planning processes as a motivating factor for initiating a proceeding in July of 2021 to update FERC's transmission planning rules (FERC 2021).

3.0 Energy Storage as a Dual-Use Asset

Because the U.S. electric grid was built before electrical energy storage technologies were widely available, it had to be designed and built as a real-time delivery system that is large enough to meet the highest demand, even if that demand only occurs for a few hours per year. Figure 5 is a load duration curve for the United States in 2019, which shows hourly electric demand sorted from the highest-demand hour to the lowest-demand hour:



Energy Information Administration

Figure 5: Hourly U.S. Electric Demand, 2019

As the figure shows, even though average U.S. hourly demand was 459,116 MW in 2019, the electric grid was built to meet a peak demand of 710,311 MW. Factoring in the necessary reserve margins and redundancy to meet reliability standards, the grid is still larger than that. That means all functions of the grid – generation, transmission, and distribution – must be designed and built to be much larger than would be required by average demand. And because the peak hours they are designed to meet only occur for a few hours a year, many grid components are underutilized most of the time.

On the transmission system, this means that even if a given line's capacity is fully contracted, that line will very rarely be used to that contracted capacity in actual operations. The Western Electric Coordinating Council (WECC), which oversees electric reliability for the Western U.S. and Canada, conducted a study of how the transmission system in its region was used in 2018 and found that there was significant unused capacity on the lines most of the time, even on fully contracted lines. **Error! Reference source not found.** summarizes WECC's finding from its 2018 State of the Interconnection report (WECC 2019).

The WECC study looked at two indicators: U75, which measures the amount of time that a given path[1] exceeds 75 percent of its thermal rating, and U90, which measures the amount of time that a path exceeds 90 percent of its thermal rating. While exact usage varied by path, on average, paths exceeded 75 percent of their rated capacity just 6.2 percent of the time and exceeded 90 percent of their rated capacity just 1.3 percent of the time. And those rates are largely driven by two heavily used paths; when they are excluded, the U75 metric falls to 3.6 percent and the U90 metric falls to 0.4 percent (WECC 2019).

2018 Path Utilization Statistics

Path	U75	U90
Path 1	19.5%	4.1%
Path 3	5.5%	0.7%
Path 4	3.4%	0.3%
Path 5	0.3%	0.0%
Path 6	0.0%	0.0%
Path 8	8.0%	1.2%
Path 14	4.1%	1.6%
Path 16	0.1%	0.1%
Path 17	1.2%	0.1%
Path 18	9.8%	0.0%
Path 19	20.7%	4.0%
Total	**6.2%**	**1.3%**

WECC

Figure 6: Transmission Utilization in the U.S. and Canada, 2018

The implication is that once deployed, transmission assets will likely have several hours of "down time" each day, during which they will have excess capacity. For an energy storage device capable of providing other grid services, this creates the possibility of transacting those services in energy markets to generate additional revenue. By sharing that revenue with customers, the storage device may reduce overall costs for all grid customers, which was the overarching objective behind FERC's policy statement.

3.1 Regional Proceedings on Dual-Use Storage

A FERC policy statement is a non-binding form of guidance and does not require action by any party. Two of the six regional markets that FERC regulates voluntarily initiated proceedings to implement the policy statement, but neither proceeding resulted in a dual-use participation model. This section will briefly review both proceedings and the issues that they identified.

3.1.1 CAISO

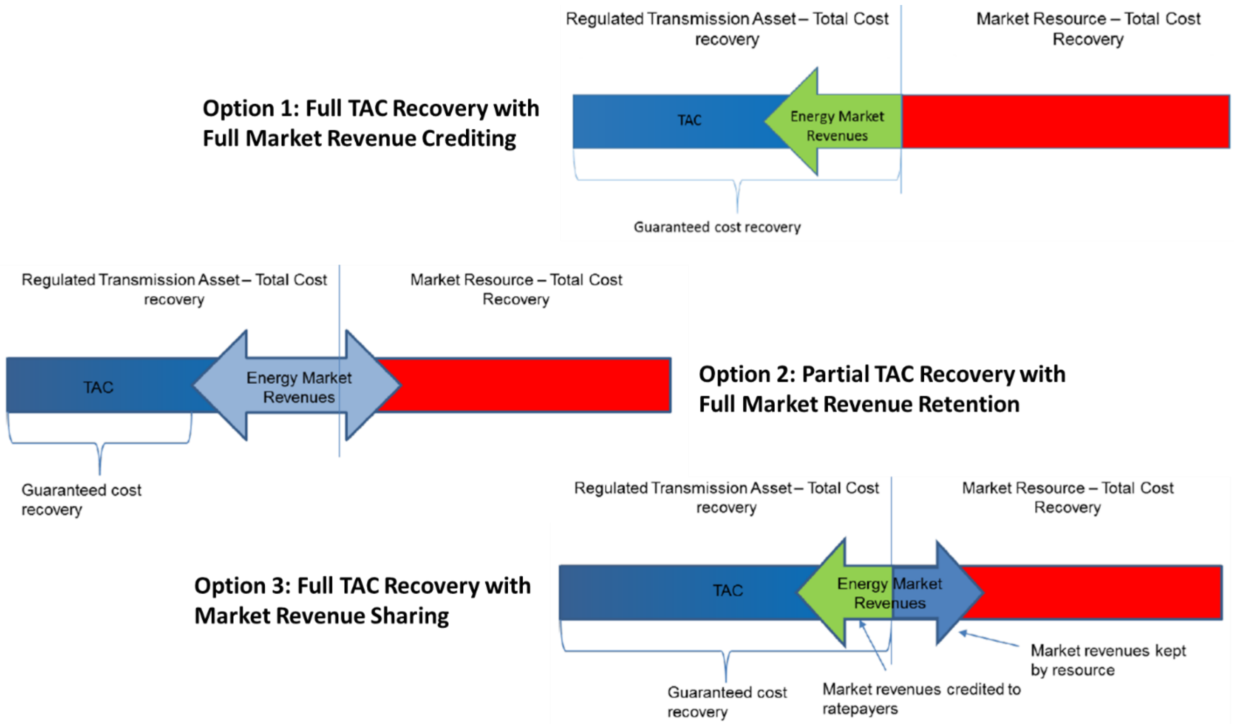
From March 2018 to January 2019, CAISO's Storage as a Transmission Asset (SATA) stakeholder initiative provided robust analysis and discussion of the regulatory and market design implications raised by FERC's policy statement.[2]

At the outset of the SATA initiative, CAISO staff placed two important guardrails on the process: 1) that energy storage would have to be selected as a transmission asset through CAISO's TPP before it could be a dual-use asset, and 2) that the TPP was beyond the scope of the SATA initiative (CAISO 2018c). While the preclusion of discussion about planning practices was a point of consternation for some stakeholders, CAISO's guardrails served to maintain the conversation's focus on the regulatory and market changes necessary to enable energy storage – once deployed as a transmission asset – to also provide market services.

[1] A path may be a single transmission line or a group of transmission lines that move electricity between the same two general areas.
[2] The proceedings of CAISO's SATA Stakeholder Initiative are available at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Storage-as-a-transmission-asset.

During the initiative, CAISO staff issued a straw proposal and then two revised straw proposals to respond to feedback and reflect the evolving discussion that took place over six public meetings. Specific issues discussed during the proceeding included:

- **Dual-use eligibility:** CAISO staff initially proposed three tiers of eligibility for storage resources deployed as transmission to also provide market services, depending on the predictability of the reliability need they were selected to meet. The first two classes would apply to resources selected to meet reliability needs that can be predicted on an hourly or monthly basis and would define their market eligibility around that need. The third class would apply to assets procured to meet an unpredictable reliability need and would prohibit market participation (CAISO 2018b). Later in the process, CAISO staff determined that establishing an asset's long-term market eligibility during the planning process was infeasible and suggested that making the determination on a day-to-day basis would likely be more practical.
- **Asset sizing**: The potential for storage assets to be oversized relative to the identified transmission need, so that the excess capacity could provide market services without affecting the device's ability to provide transmission services, elicited concern from all parties. Since SATA resources would not pay interconnection costs under CAISO's proposal, CAISO staff wondered about the allocation of interconnection costs for oversized dual-use assets and how to guard against those assets leveraging their regulated status to unfairly impact other market participants, in violation of FERC's policy statement. Developers, meanwhile, were worried that the ISO would be unable to differentiate between the transmission and market components and would end up using the market share of the storage asset for transmission needs.
- **Market bidding**: From the ISO's perspective, a dual-use asset's ability to recover its costs through regulated rates may lead it to submit artificially low bids when participating in the market. Such behavior, ISO staff argued, could suppress prices for other market participants and result in overuse of the asset that would reduce its useable life for transmission functions. If that reduced life required the asset to be refurbished or replaced ahead of schedule, it would result in higher costs for ratepayers. To remedy these concerns, CAISO staff proposed a transmission revenue requirement (TRR) credit mechanism, which would calculate the reduction in useful life for the storage asset each time it is dispatched into the market and make a commensurate reduction in the asset's TRR, the guaranteed cost recovery that it receives as a regulated transmission asset. ISO staff argued that making asset owners internalize the costs of market participation in this manner would ensure they take a judicious approach to device management and reflect the true cost of using their device in market applications when formulating bids (CAISO 2018c).
- **Transmission recall**: Storage developers expressed concern that they would face penalties if they made market bids during a window in which they were authorized for market participation, but were then unable to deliver on those bids due to being recalled for transmission services.
- **Cost recovery**: The topic most extensively discussed in the SATA initiative was how dual-use energy storage assets would recover their costs. CAISO staff initially proposed two possible approaches. In the first, the asset would recover its full cost of service through regulated transmission rates and refund all market revenues to customers. In the second, the asset would recover a prorated amount of its costs through regulated transmission rates (based on a reasonable projection of the device's market revenues) and then keep all market revenue (CAISO 2018b). CAISO staff later proposed a third option, in which an asset would recover its full cost of service through regulated transmission rates and then split all market revenues with customers (CAISO 2018c). Figure 7 illustrates CAISO's three rate design proposals for dual-use energy storage, based on how much of their cost recovery would be guaranteed through fixed rates via CAISO's Transmission Access Charge (TAC) in blue and how energy market revenue (represented by the arrows, with green arrows indicating revenues credited back to customers and blue arrows indicating revenues kept by the owner) would be treated.



CAISO 2018c

Figure 7: CAISO Staff Proposals for Cost Recovery by Dual-Use Energy Storage Assets

CAISO suspended the SATA initiative in January 2019, pending the conclusion of a related initiative examining market design for energy storage and distributed energy resources. The related initiative concluded in September 2020 and CAISO has not yet indicated when it will resume the SATA initiative.

3.1.2 MISO

At the request of its Energy Storage Task Force, MISO initiated a stakeholder proceeding in August 2018 to study the potential for energy storage to serve as a transmission solution. Fairness was a defining theme of MISO's proceeding, where much of the discussion centered on ensuring that storage deployed as a transmission or dual-use asset would not negatively impact existing generation resources or those in the interconnection queue.

MISO staff's initial issue paper in the proceeding (MISO 2018) mentioned FERC's policy statement and included proposals for enabling energy storage as a dual-use asset, and the initiative explored several relevant issues as a result.

- **Transmission planning**: Pursuant to Order 1000, the MISO Transmission Expansion Planning (MTEP) process allowed stakeholders to propose energy storage alternatives, but MISO staff indicated that the process for proposing alternatives did not adequately recognize energy storage and that improvements would be necessary to allow storage alternatives to be equally considered. Staff also proposed specific planning assumptions for storage and data requirements from parties proposing storage alternatives (MISO 2018).
- **Interconnection queues:** The relationship between how a device would be used and how it would interconnect to the grid was a focal point of the MISO proceeding. MISO staff initially proposed two alternatives: 1) requiring all storage alternatives to have an interconnection agreement before they

could be studied in MTEP; or 2) allowing transmission-only storage assets to bypass the interconnection queue, but to go through the queue and secure an interconnection agreement before providing any market services (*id)*.

- **Cost recovery:** For dual-use storage assets, MISO staff proposed four cost recovery options. The first three were effectively the same as the CAISO alternatives, but MISO also added a fourth proposal in which assets needed for transmission service on a seasonal basis could receive fixed recovery as a transmission asset during the season in which they were needed and be market assets for the remainder of the year (*id.*).

After public comments elucidated the numerous challenges associated with enabling dual-use storage, MISO staff proposed to focus the proceeding on identifying the measures necessary to enable storage as a transmission-only asset (SATOA), and revisit the question of dual-use energy storage in a subsequent future phase. The outcome of the MISO proceeding was a filing at FERC to implement a process for studying energy storage alternatives within transmission planning and the requirements by which SATOA assets would be bound.

Multiple parties objected to MISO's filing, generally arguing that it was discriminatory toward other resources, did not adequately explain the process for studying SATOA resources, unfairly allowed MISO to manage state of charge for SATOA assets, and failed to consider market impacts (FERC 2020c). In response, FERC suspended the proceeding and held a technical conference to explore the complaints.

At the conclusion of the proceeding, FERC determined that MISO had met its burden of proving that its SATOA framework was fair, just, and reasonable and allowed the tariff to go into effect with minor revisions to address stakeholder concerns. Those revisions clarified the situations in which storage alternatives would be considered in MTEP, what costs would be included in the planning assumptions, and that SATOA assets would only transact in markets to charge or discharge based on their designated transmission functions.

MISO launched a new initiative in January 2022 to revisit the matter of dual-use energy storage.

3.2 Challenges for Market Participation by Dual-Use Energy Storage

The CAISO and MISO proceedings stemming from the FERC policy statement highlight multiple underlying challenges that a dual-use participation model must resolve. While both proceedings provided a forum for robust discussion and exploration of these challenges, neither has yet resulted in a model that addresses them.

Many of these challenges are the result of the rigid regulatory lines between the transmission and generation functions in wholesale markets. The resulting tension between generation and transmission owners results in a zero-sum worldview in which generation owners generally perceive storage deployed <u>as</u> transmission reduces their investment opportunities, while transmission owners perceive storage deployed <u>in place of</u> transmission as doing the same for them.

The tension between transmission and generation owners was particularly evident in the FERC proceeding on MISO's SATOA filing; a consortium of MISO transmission owners was one of only two entities to file in support of the SATOA tariff, while more than two dozen entities, many of them utilities and generation developers, opposed it. Protesters successfully convinced FERC to limit the contingencies under which storage could be analyzed in the TPP and Commissioner James Danly, writing in dissent of FERC's approval of the SATOA tariff, argued that the decision "… impermissibly blur[red] the line between generation and transmission" (FERC 2020c).

This regulatory paradigm has resulted in multiple, specific barriers that prevent an energy storage asset from moving between transmission and generation functions in a manner consistent with the principles of the FERC policy statement. Specific details may vary slightly by market region, but in principle a dual-use participation model must answer three basic questions: **When** will the asset participate in the market? **How** will the asset participate in the market? **Where** will the asset recover its costs? Answering those questions requires that the following issues be addressed.

When an asset participates in the market:

- **Market participation windows**: The CAISO initiative demonstrated the challenge of determining how and when a dual-use asset may participate in the market. CAISO's initial proposal of making that determination during the TPP proved to be unworkable, and CAISO indicated that market availability for dual-use assets would likely have to be determined a daily basis. But even with that increased resolution of market availability, guidelines are necessary to determine that market participation does not jeopardize the asset's ability to meet its transmission function.
- **Recall**: The potential for dual-use assets to be released to the market, but then recalled to meet an unanticipated transmission system need increases risk for project developers. In addition to making revenue streams uncertain, unplanned recalls raise the possibility of penalties for failing to deliver on market commitments.
- **Asset sizing and interconnection**: In addition to the impact that dual-use storage can have on current market participants, decisions about how an asset is designed and interconnected to the grid may impact future market participants. Whether a storage project identified in transmission planning should be allowed oversize to have excess capacity available for full-time market participation was a question raised but not answered in both the CAISO and MISO proceedings. As both proceedings identified, the possibility raises complicated questions of allocating interconnection costs between the transmission and generation functions, ensuring that the generation component does not gain unfair market access by free riding on the transmission component, and maintaining fairness for other generation resources in the interconnection queue.

How an asset participates in the market:

- **Asset definition**: ISO operations are founded on a firm structure of definitions that define assets not by technology, but by operational characteristics such as dispatchability, responsiveness, and duration. Those definitions inform everything about how the asset participates in the market, from contractual arrangements to market product eligibility to cost recovery. Allowing dual-use storage to participate in generation markets requires an operational definition that recognizes transmission service as the asset's primary responsibility and allows it to move in and out of market participation subject to that constraint.
- **Market impacts**: The FERC policy statement requires that dual-use storage assets not create adverse market impacts. Because they can bypass interconnection queues and recover most of their costs (or all, depending on the cost recovery system) through regulated means, dual-use storage assets would have easier access to the market and a different cost structure than other market resources. Absent recognition and correction for this inequity, dual-use assets may submit artificially low market bids, suppressing prices for remaining market participants.
- **Operational control**: The final principle in FERC's policy statement was intended to preserve the integrity of market operators by requiring them to return operational control of a dual-use asset to the owner for market participation. FERC reasoned that an independent system operator cannot be independent if it is responsible for bidding a resource into the market, so a dual-use participation model must allow for fluid transition of operational control between the grid operator and asset owner.

- **Asset life management**: Aggressive market participation by a dual-use asset would wear the device out ahead of schedule, requiring early refurbishment or replacement that could undermine the objective of dual-use assets by increasing costs for customers. To avoid that outcome, a dual-use participation model should impose reasonable participation constraints.

Where an asset recovers its costs:

- **Cost recovery**: Achieving the objective of FERC's policy statement – lowering grid costs by enabling cross-functional assets to provide a wider range of services – requires balancing two principles. The first, identified in the policy statement, is that dual-use assets not be overcompensated for those services, as that would defeat the purpose of generating savings that can be passed on to customers. However, asset owners need to be able to keep some of the market revenue as an incentive for market participation. Balancing the costs that are recovered through regulated and market rates in a manner that comports with FERC's principles is a key component of a dual-use participation model.

4.0 Identifying a Dual-Use Participation Model

As the previous sections have explained, identifying a participation model for dual-use energy storage assets is a complicated process that must address multiple barriers across multiple ISO processes. Significant effort has already been expended on answering these questions at FERC as well as CAISO and MISO; those discussions have provided a solid foundation upon which this project has been able to build.

The objective of this project is to identify a participation model that would enable energy storage to provide services both as a regulated transmission asset and as a competitive market asset, and then to quantify the resulting benefits of such an approach. Because market structures and rules vary by region, developing a universal model that can be readily applied in any region is not a practical objective. But by identifying the principles of a viable dual-use participation model and alternatives for satisfying those principles, this work may illustrate the value of dual-use energy storage and further inform future proceedings as ISOs revisit or initiate efforts to implement FERC's policy statement.

In developing a participation model that would resolve the barriers in transmission planning and market operations identified in the previous sections, the research team was bound by three foundational principles: reliability, incrementalism, and balance.

Reliability: A dual-use asset's market participation must not jeopardize its ability to serve the transmission function for which it was initially selected. As discussed in Section 2, grid operators are subject to mandatory reliability standards that govern how the electric grid is planned and operated. Violation of these standards carries strict consequences, both physical (outages, damaged equipment) and financial (fines, lost revenue, repairs). If energy storage is selected in a TPP, then maintaining safe and reliable operations requires that the device be available to perform its designated function whenever needed. Market participation should therefore be viewed as a secondary benefit for dual-use storage, one that can create offsetting revenue that can be shared with customers to reduce grid costs, but never the primary objective.

Incrementalism: Dual-use participation models should be based in established market practices and principles to the greatest extent possible. Implementing operational changes within an ISO is a complicated, time-consuming process involving extensive stakeholder proceedings at the ISO level and then again before FERC. These processes serve a valuable purpose in thoroughly vetting proposals and building consensus but add cost and time to the implementation of new processes. To increase stakeholder confidence in the model and limit the amount of change that would have to be vetted through regulatory proceedings, the research team has endeavored to build a participation model using existing, proven practices already in place in one or more ISOs.

Balance: A dual-use participation model must recognize competing priorities and seek to balance them. This report has identified some of the conflicting objectives associated with dual-use energy storage. FERC's policy statement indicated that system operating costs could be reduced by returning the revenue from a dual-use asset's market participation to customers, but asset owners need to retain some of that revenue as an incentive for them to participate in the market. And while market participation is necessary to achieve offsetting revenue that can be shared with customers, too much market participation may reduce the useful life of the asset and require it to be refurbished or replaced ahead of schedule, which could result in an overall increase in system costs. Optimal deployment of dual-use energy storage consistent with FERC's objectives and principles requires identification of these competing priorities and a balanced approach to addressing them.

The remainder of this section will present the key principles for facilitating energy storage's inclusion in transmission planning and then enabling market participation by dual-use storage. Alternative approaches for satisfying each principle, demonstrated practices where available and theoretical practices where not, will also be presented.

4.1 Facilitating Energy Storage's Inclusion in Transmission Planning

Identifying cost-effective opportunities for the initial deployment of dual-use storage during the TPP consists of two principles:

- Establish clear, transparent processes for the proposal and study of energy storage
- Prepare a reasonable forecast of future market revenues to capture the net present cost of the asset to transmission customers.

Establish clear, transparent processes. Order 1000 places the burden of including energy storage in TPPs on project developers. But absent clear procedures for how those projects may be proposed and how they will be studied, those proposals and those analyses do not appear to be occurring in most regions. It is not a coincidence that the only two regions to have developed specific processes for studying energy storage (CAISO and MISO) are the only two regions that have studied energy storage. Those two regions, however, present a clear contrast in how they included storage in their respective TPPs.

In MISO, identifying how storage would be studied in the MTEP process was a major stakeholder initiative that thoroughly explored the issue and resulted in extensive tariff amendments to codify the specific conditions under which SATOA assets may be proposed, how they will be studied, and how they will be operated if selected (MISO 2021).

To inform the analyses identified in the box to the right, MISO requires parties that propose a SATOA alternative to provide detailed information about the device's technical specifications and costs. In addition to analyzing how the device would impact the current MISO system, planners also study the impacts that it would have on future generation resources that will soon interconnect near the SATOA. If the presence of the SATOA would require additional grid upgrades to interconnect those generation resources, then those upgrades are included in the SATOA's costs.

MISO's Seven Factors for SATOA Analysis

MISO's SATOA tariff describes seven factors considered when analyzing storage in the MTEP:

- Technical ability to meet the identified need
- Maximum capacity required to meet the need
- Energy component (charge/ discharge) required to meet the need
- System reliability analysis of inverter
- Lifecycle cost comparison
- Construction factors (lead time, right of way, etc.)
- Impact on queued generators

CAISO, on the other hand, employed a much less prescriptive approach. At the beginning of each TPP cycle, CAISO allows stakeholders to provide input into the unified planning assumptions that will be used in the process, including the proposal of "preferred resources" that CAISO staff should consider. Given California's emphasis on energy storage in recent years, storage has naturally worked its way into the unified planning assumptions. This essentially places the onus on CAISO planning staff to identify and study storage alternatives and creates a receptive environment for storage alternatives proposed by transmission owners or stakeholders. Where MISO's transmission planning tariff has seven pages describing how and when storage will be studied in detail, CAISO's tariff only contains passive references to storage as a possible transmission alternative and analytical details are handled on a case-by-case basis in the TPP.

The narrative explanations in CAISO's 2017-2018 Transmission Plan (CAISO 2018a) provide insight into this process. In the two cases in which storage was selected in the plan (discussed in Section 1 of this report), the plan describes the reliability issue, available alternatives and costs, and the solution selected. While the storage alternative selected in Oakland was a joint proposal from the local transmission owner and load-serving entities, the storage alternative selected in Dinuba appears to have been identified by CAISO staff.

Clearly CAISO and MISO operate under different circumstances. CAISO and its stakeholders all operate within a single state energy policy regime, which facilitates a looser approach founded on shared objectives. MISO's 15-state territory, however, requires a more regimented approach to ensure balance across a greater diversity of stakeholders and state policies. Though the two approaches to do not lend themselves to a direct comparison, each has led to the identification of cost-effective storage alternatives, and they illustrate the range of options available to regional transmission planning coordinators for creating greater clarity and certainty for energy storage alternatives in the TPP.

Forecast future market revenues. Offsetting revenue earned through participation in a wholesale market and credited back to transmission customers over time reduces the rates that the transmission customers pay for the asset. Accounting for these reductions on an upfront basis during the TPP is necessary to ensure that the true cost of a dual-use storage alternative is identified and used as a planning input. Table 3 illustrates the effect of market revenue sharing on the total cost of a dual-use storage asset, using a generic project assumed to cost $10 million with a useful life of 40 years and an authorized rate of return of 10 percent, which provides ratepayers with an annual market credit of $50,000.

Table 3: Comparison of Project Costs, With and Without Market Revenue Crediting

Year	Transmission Revenue Requirement	Market Revenue Credit	Net Transmission Revenue Requirement
1	($1,250,000)	$50,000	($1,200,000)
2	($1,225,000)	$50,000	($1,175,000)
3	($1,200,000)	$50,000	($1,150,000)
…			
38	($325,000)	$50,000	($275,000)
39	($300,000)	$50,000	($250,000)
40	($275,000)	$50,000	($225,000)
Total	($30,500,000)	$2,000,000	($28,500,000)
Net Present Value	**$10,000,000**		**$9,511,047**

As Table 3 demonstrates, if this $10 million asset can credit $50,000 in market revenue back to transmission customers during each year of its operation, then the total amount that transmission customers pay for that asset will be reduced by $2 million.

From a planning perspective, those annual reductions in the asset's TRR mean that on a net present value basis, its costs are reduced to about $9.5 million. Including a reasonable market revenue forecast in resource cost assumptions ensures that the true cost to customers is considered when the storage alternative is compared against other options and increases the accuracy of planning outcomes.

4.2 Dual-Use Energy Storage Participation Framework

FERC's policy statement identified three foundational objectives to guide the participation of dual-use energy storage assets in markets: 1) avoiding double recovery; 2) minimizing adverse market impacts; and 3) maintaining ISO/RTO independence. But as the CAISO and MISO proceedings demonstrated, creating a dual-use participation model involves additional layers of complexity and competing objectives that must also be resolved.

As previously stated, the objective of this project is not to develop a one-size-fits-all participation model. To ensure flexibility and adaptability for various regions, this paper instead identifies the key elements of a dual-use participation model and points of flexibility. Using these foundational components, grid operators and stakeholders may craft participation models based on each project's characteristics, ISO policy, and the characteristics of the storage technology being considered.

In the simplest terms, the participation model must answer three questions, namely *when* a dual-use device participates in the market, *how* it participates in the market, and *where* it recovers its costs. To answer these questions, we have identified a dual-use participation framework that consists of three key elements: establishing market participation windows in advance; creating flexible market products and resource definitions; and balancing cost recovery mechanisms to incent market participation.

Additional topics that are not directly implicated in market participation mechanisms, such as procurement, ownership, and whether the asset should be allowed to oversize for market participation, will be briefly addressed in the next subsection.

4.2.1 Establish Market Participation Windows in Advance

Once the reliability need has been identified in the TPP, determining when the device can participate in markets is a necessary step to enable estimation of the market revenues that can be returned to customers. But as the CAISO proceeding concluded, long-term commitment to predetermined market participation windows is infeasible; changing grid conditions require those windows be revisited on a seasonal or even daily basis.

Regardless of the interval at which those windows are determined, the asset owner should receive advance notice of its anticipated reliability obligations so the owner can make informed bids into the market without infringing on those obligations. If possible, day-ahead notification prior to the closing of day-ahead markets is preferrable.

When determining when a dual-use asset can participate in the market, the following points of flexibility exist:

- **Eligibility windows**: A dual-use asset's ability to participate in the market may vary based on the nature of the reliability need it is meeting. For predictable needs (such as those that only occur during peak, for example), defined market windows may be appropriate.

Relevant Practice: CAISO's Day-Ahead Transmission Modeling

When solving for generation needs in the day-ahead market, CAISO also identifies available transfer capacity on its transmission pathways for the day, based on the technical capability of each line as well as existing rights and obligations. This analysis is completed 90 minutes before the close of day-ahead market bidding. From the perspective of a dual-use storage asset, this practice could be used to identify the periods during which the asset can safely participate in the market based on anticipated system needs. This in turn would enable the asset owner to submit informed bids into the day-ahead market.

- **State of charge management**: Instead of defining specific times of day during which an asset can participate in the market, grid operators may allow the device to participate in the market at any time, subject to a minimum state of charge that the device must maintain. This may be the preferred approach when transmission needs are unpredictable, to ensure that the device has sufficient charge to be called upon for transmission service at any time.[1]

4.2.2 Create Flexible Market Products and Resource Definitions

How a dual-use asset participates in energy markets encompasses many of the principles identified in Section 3.2. In addition to meeting FERC's requirements related to operational control and market impact mitigation, the mechanism must also manage the useful life of the asset and allow for smooth transitioning between functions during reliability events.

To satisfy FERC's requirements related to operational control, a market participation model should first require the asset owner to bid the resource into the market during approved windows subject to any bid formulation requirements imposed to ensure fairness for other market resources. To assuage owner uncertainty about being recalled from market service and facing penalties, the mechanism should allow for instant, no-fault redispatch of the asset for transmission purposes. Depending on the size of the storage asset, limits on the amount of capacity it can commit to markets may be necessary to manage market impacts and the amount of residual services to be procured in the event that the asset is redispatched for transmission.

When determining how a dual-use asset can participate in the market, the following points of flexibility exist:

- **Asset definition**: One method of enabling dual-use participation is to develop a resource definition that captures the market limitations of dual-use assets. Pursuant to Order 841, ISOs have recently developed mechanisms for compensating energy storage assets for the services that they provide. Many ISOs also have asset classes for resources whose dispatch is limited by external factors such as environmental restrictions or contract terms and resources that are required to provide service at certain times to maintain reliability. Dual-use assets have elements of all these asset classes; existing principles may be adapted into a new resource class that can bid into markets as a storage asset that may be reassigned for transmission as necessary.
- **Market product creation**: Alternatively, the unique nature of dual-use storage assets may be captured in a market product that allows resources to simultaneously bid into multiple grid functions. Some regions already have processes that allow resources to simultaneously bid into energy and ancillary service markets. Modifying products like these or adding a new product that includes a transmission function in the bid would allow grid operators to dispatch the device to market or transmission functions in real time based on current grid needs and provide the necessary bidding flexibility for dual-use storage owners.

[1] In the CAISO initiative on dual-use storage, staff argued that a storage asset serving an unpredictable transmission need should not be eligible for dual-use treatment. We propose this alternative as a possible means by which the benefits of dual-use storage may be realized while reserving sufficient charge for the transmission need. This approach may require the asset to be slightly oversized to have sufficient capacity for limited market functions. This topic will be discussed in Section 4.3.1.

> **Relevant practice: Dual Bidding in CAISO**
>
> When submitting energy bids in the day-ahead or real-time CAISO markets, asset owners may indicate in the bid how much of their capacity is available for ancillary services and at what price. CAISO then solves for the ancillary service market with these bids, adjusts the energy bid for resources that were selected for ancillary services, and then solves for the energy market.

> **Relevant practice: Reserve Procurement in ISO New England**
>
> ISO New England (ISO-NE) procures spinning and non-spinning reserves twice a year in its Forward Reserve Market. In real-time energy market operations, any incremental reserve needs are co-optimized with energy market bids to ensure that customer needs and reliability requirements are both met by the lowest cost available resources.

- **Bidding rules**: Markets already have rules for mitigating the bids of certain resources to limit their market power. Requiring a storage asset to consider the costs associated with market dispatch in its bid can similarly help ensure that it does not use its status as a regulated asset to underbid other market participants. Energy losses, variable operations and maintenance, and opportunity costs are some of the costs that market operators may require to be included in bid formulation for a dual-use storage asset. CAISO staff's proposed TRR crediting mechanism introduced in Section 3 is another potential means of enforcing fair and accurate bid formulation.
- **Market limitations**: Another means of curbing a dual-use asset's ability to unfairly impact energy markets and reduce its useful life from excessive use is to limit the services that it can provide. Capping the amount of capacity that large devices can bid into markets can help preserve market integrity, while limiting market participation to services that will only lightly use the device (such as frequency regulation or operational reserves) can prevent overuse of use-limited assets such as batteries.

4.2.3 Balance Cost Recovery Mechanisms to Incent Market Participation

Achieving FERC's goal behind the policy statement of sharing market revenue with transmission customers as a means of reducing electric system costs requires a thoughtful approach to how a dual-use asset recovers its costs. In determining how an asset's cost recovery will be split between regulated and market functions and how market revenues will be divided, a balance must be struck between giving the asset owner a reasonable opportunity to recover investment expenses and preserving an incentive for the owner to participate in the market and earn offsetting revenue.

As discussed in Section 3.1, the CAISO proceeding identified some of the flexibility in determining how to balance those objectives. ISOs may want to consider adopting multiple options and allowing asset owners to choose their preference.

- **Partial fixed recovery with revenue sharing**: Once annual market revenues have been forecast, the annual TRR may be reduced by a portion of that annual revenue (though ideally not the full amount, since the asset owner would have little incentive at that point to participate in the market). The asset owner then retains all market revenues. This approach avoids the need for splitting the revenue but does raise the risk profile for the owner and creates a strong incentive for aggressive market participation that could wear out the asset ahead of schedule.

- **Full fixed recovery with revenue sharing**: For asset owners that prefer the security of full fixed recovery, some form of revenue sharing will be necessary. The percentage of revenue the owner keeps and the percentage that is returned to customers would likely need to be negotiated on a case-by-case basis, subject to the performance characteristics, costs, and forecast revenues of each project. Grid operators may also want to consider the use of sharing bands, a commonly used approach in regulatory ratemaking that allows for the revenue split to vary at different levels of revenue as a means of managing incentives and usage.
- **Hybrid approach**: CAISO staff's proposed TRR crediting mechanism is a hybrid approach to cost recovery that addresses the concern of prematurely wearing out a device through aggressive market participation by forcing asset owners to internalize the costs of market usage. Staff proposed to calculate the reduction in useful life associated with each charge/discharge cycle of the storage asset and then reduce the asset's fixed revenue requirement by a commensurate amount. This approach would ration usage of the asset for market purposes and maximize its useful life but would likely also prove controversial and administratively burdensome. And while it applies most directly to batteries whose useful lives are dependent on cycling, it may also be appropriate to quantify incremental maintenance needs for PSH resources under market usage and require asset owners to internalize those costs as well.
- **Cap and Floor mechanism**: In the United Kingdom, to be responsive to the need for merchant transmission development to enable large-scale imports and exports of energy to the European mainland, the market regulator, Ofgem, developed the Cap and Floor mechanism. In simple terms, the mechanism supports the development of merchant transmission where otherwise private developers were not able to secure financing due to uncertainty of long-term revenues. The Cap and Floor mechanism establishes a rate recovery floor, that is a minimum return that transmission projects are guaranteed to receive from customers through regulated transmission rates. The scheme also establishes a cap, or a maximum return projects can receive, permitting market participation while protecting ratepayers and preventing windfall profits for the developer. Any revenues generated above this cap are transferred to the system operator and used to reduce transmissions charges across the system. Since the mechanism was implemented in 2012, there are five installed and operating transmission projects. Review of these projects carried out by Ofgem have indicated that the scheme is operating as intended (Ofgem 2016, 2018).

4.3 Other Issues for Consideration

The preceding section identified the essential elements of a dual-use participation framework, but there are other considerations and related issues that may need to be addressed as well. This section will briefly discuss some of these options.

4.3.1 Device Oversizing

As discussed in Section 3, both the CAISO and MISO initiatives explored the question of whether storage-as-transmission assets should be allowed to oversize relative to the identified transmission need and use the excess capacity to provide market services. Since the transmission-facing project component would not be subject to interconnection studies or costs, market participants argued that allowing the oversized, market-facing component to free ride on that interconnection would give it an unfair advantage and subvert the market.

Proposals to address this potential inequity included requiring that the owner pay the prorated share of interconnection costs associated with the asset's market capacity and that the asset go through the interconnection queue before providing market services. While prorating costs is a straightforward process, requiring the asset to go through the interconnection queue creates a mismatch in timing. The decision to oversize must be made up front but working through an interconnection queue to provide market services can take two to four years (Caspary, Goggin, Gramlich, and Schneider 2021). This creates an extended idle period between construction and clearance for market operations during which the market component of the asset would be unused and unable to earn offsetting revenue that can be shared with customers.

The question of oversizing a transmission asset is particularly relevant to PSH. Given their scale, PSH facilities could conceivably be sized such that only a fraction of their capacity is needed for transmission purposes. Having clear policies in place for equitable cost allocation and market participation by oversized assets would ensure fair consideration of all storage technologies and facilitate the selection of projects that offer the broadest set of grid benefits.

Ultimately, the decision about whether and under what conditions a dual-use asset should be able to oversize is a policy decision made by grid operators in consultation with stakeholders. That conversation may be narrowed and focused by limiting the potential for oversizing to assets serving an unpredictable reliability need, to ensure sufficient capacity to generate market revenues while constantly maintaining sufficient reserves to be redispatched for its reliability need at any time. To address the gap between asset construction and interconnection queue clearance, grid operators may consider accelerated study processes for dual-use assets or some means of merging the transmission project with a nearby queued market project (such as a joint venture or allowing developers of nearby competitive assets that would soon interconnect to amend their projects to address the transmission need as well).

4.3.2 Procurement and Ownership

Once identified, some transmission investments are opened for competitive procurement and some are assigned to an existing transmission-owning utility. ISOs have different processes for determining where this line is drawn; in some regions it is a function of the transmission voltage at which the project would connect and in others it is based on the timing of the need. Because of the competitive implications of dual-use assets and the relative speed with which some storage technologies can be deployed, traditional transmission procurement guidelines may not make sense to apply to storage alternatives. Competitive procurement of dual-use assets may increase flexibility and result in lower cost projects. Ownership of dual-use assets is another factor that will vary by region. Because FERC requires market participation to be under the control of the asset owner, third-party ownership will be necessary in regions where utility ownership of generation assets is prohibited. In regions where transmission and generation ownership are mutually exclusive, dual-use storage may require joint ventures between transmission and generation owners.

5.0 Summary and Next Steps

Dual-use energy storage can potentially improve grid efficiency while reducing costs for all customers. Deployed as a transmission asset, storage can increase the flexibility of the transmission system while protecting and extending existing infrastructure and deferring or eliminating the need for costly new investments. Unlocking the ability of such a device to also access energy markets when not needed for transmission would generate revenue that can be shared with customers to lower their energy costs. This usage model presents significant potential opportunity for PSH facilities in particular, as their scale and development cycle align well with transmission applications, but they are also capable of providing a wide range of generation services.

But as the CAISO and MISO proceedings demonstrated, developing enabling regulations for dual-use storage is a complicated and controversial process. Regulatory structures have drawn bright lines around the transmission and generation functions, and those lines are not easily crossed.

Before a dual-use model can be created, barriers in transmission planning processes that prevent the selection of energy storage must be addressed:

- Lack of clarity for how and when storage will be considered
- Difficulty representing storage in power flow models
- Weak links between transmission and generation planning processes
- Financial disincentive for utilities to consider lower-cost options
- Lack of regulatory review

Practices in CAISO and MISO provide templates for clarifying how and when storage will be considered; CAISO requires planners to proactively identify those opportunities, while MISO has a written procedure detailing how stakeholders may propose storage alternatives.

Creating a participation model that allows dual-use storage assets to move between transmission and generation functions must answer three questions:

1. **When** will the asset participate in the market? Establishing clear parameters for when an asset may participate in the market—through defined temporal windows or by setting a state of charge floor—allows for the asset owner to make informed bids into the market. It also facilitates reasonable forecasts of future revenues in the transmission planning process, so that the asset's true net present cost can be used.

2. **How** will the asset participate in the market? A dual-use asset must be able to freely move between generation and transmission functions as needed by the grid, without incurring penalties. That flexibility can be created through resource definitions and market products that establish a dual-use asset class and/or allow resources to simultaneously bid into market products and transmission service, then be dispatched as need in real time.

3. **Where** will the asset recover its costs? When determining which costs will be recovered through regulated transmission rates and which costs will be recovered through competitive market revenue, incentives for the device to participate in the market and earn offsetting revenue must be maintained.

This paper does not answer every question raised by dual-use energy storage, as many of those questions are unique to the existing structure of a given region. But by identifying the key principles that a dual-use participation model must satisfy and options for meeting those principles, this paper may be of use to grid operators, utilities, project developers, and other ISO stakeholders in future proceedings on dual-use energy storage. By facilitating identification and consensus building on major policy considerations, this work may allow ISO staff and stakeholders to focus on adapting the framework to their unique situation.

In the next step of this project, the participation model identified in this paper will be used to create a techno-economic model to measure the economic benefits of dual-use storage deployment. This paper has been focused on enabling market revenue streams by a dual-use storage asset; the next paper will quantify those revenue streams.

Beyond this project, future work on the topic of dual-use storage may focus on enabling increased flexibility for energy storage assets to serve multiple functions. This project has stayed within the confines of the FERC policy statement and focused on the necessary regulatory adaptations to enable the implementation of that statement. While this type of dual-use storage does represent a new level of flexibility in grid operations, it is still binary in nature. It allows storage to act as transmission or generation, but at any given point in time it is one or the other. Its operations are constrained by regulatory structures that require it to be sized based on a transmission need but complicate its ability to add additional capacity to provide other services. Additional study to identify the regulatory changes and benefits of increased flexibility for multifunction storage could potentially add operational and economic benefits.

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Appendix A: Regional Transmission Planning Processes

This appendix provides an overview of TPPs in each of the Order 1000 planning regions. Generally, these summaries seek to answer the following questions:

1. What is the planning cycle?
2. How and when are planning assumptions made?
3. What are the critical decision points and when are they made?
4. How are non-transmission alternatives considered under current practice? Where are the “access points” for energy storage?
5. Once projects have been selected, how are they procured?
6. What are the opportunities for stakeholder participation and input?

A.1 CAISO

CAISO’s TPP lasts for approximately two years, with cycles staggered such that a cycle concludes each year to comply with NERC’s requirement for annual plans. Plans have a 10-year horizon. Cycles launch every December and are divided into a three-part process that lasts from 16 to 26 months depending on the investment needs that the plan identifies.

- Phase 1 – December to March (4 months): CAISO develops unified planning assumptions for the cycle and develops a study plan identifying the technical studies that will be done.
- Phase 2 – April to March (12 months): CAISO works with transmission owners within its system to conduct a reliability assessment of the transmission system and technical studies defined in the study plan. CAISO identifies potential transmission needs and evaluates transmission and non-transmission alternatives for meeting those needs. After considering stakeholder feedback, CAISO recommends solutions in a draft transmission plan, which is submitted to the CAISO Board of Directors for approval.
- Phase 3 – April to January (10 months): If the final transmission plan approved by the Board of Directors identifies a need for projects that are eligible for regional cost allocation, there is a competitive solicitation process to procure those facilities.

The purpose of the unified planning assumptions and study plan is “to clearly articulate the goals and assumptions for the various public policy and technical studies to be performed as part of phase two of the TPP cycle.” (CAISO 2020). CAISO works closely with the CPUC and California Energy Commission, which oversee the state’s integrated resource planning process for generation resources, to develop assumptions about load forecasts and the size, location, and timing of planned generation resource additions during the planning period.

CAISO also solicits stakeholder comments to assist in formulating assumptions related to how energy policies should be represented in the plan, participation by demand response resources, non-transmission alternatives that should be considered, and suggested studies to identify economic transmission projects. In January of even years, CAISO also solicits requests for consideration of interregional projects.

Stakeholders have two opportunities to provide input into the unified planning assumptions: in written comments when CAISO issues a market notice at the beginning of the process (usually in mid-December) calling for stakeholder input and in written and verbal comments in February when CAISO posts the draft study plan and convenes a public stakeholder meeting for additional feedback.

After that meeting, stakeholders may also submit requests for CAISO to study potential economic transmission projects by identifying a system constraint and proposing a solution that may reduce the constraint while potentially reducing overall system costs. Proposals are vetted by CAISO staff for relevance (whether an actual constraint has been identified) and feasibility (whether the proposed solution is technologically capable of alleviating the constraint); proposals determined to be viable are prioritized and included in the study plan.

Once the study plan is finalized, the process moves to Phase 2. CAISO begins this phase by conducting the reliability studies required by NERC TPL-001-5 and the other technical studies identified in the study plan. Two technical studies are done every cycle: a long-term congestion revenue rights feasibility study and a local capacity requirement study that informs subsequent resource adequacy proceedings at the CPUC.

By August 15, CAISO posts the preliminary results of the reliability studies and opens a two-month window for stakeholders to propose solutions for addressing any identified reliability needs. Transmission owners have 30 days to submit their proposals, which are presented alongside the preliminary results at the second stakeholder meeting in mid-September, which is followed by a two-week comment period. CAISO incorporates the feedback and the proposed solutions into a final reliability study, which is posted by the end of October.

During the submission window, CAISO conducts the public policy studies identified in the study plan and the economic study proposals that made it through the vetting process. Preliminary results for those studies are posted in November, followed by the third stakeholder meeting and another comment period.

Once the reliability, public policy, and economic studies have been submitted for public review, CAISO incorporates the feedback and combines the study into a draft transmission plan that summarizes all identified transmission needs and proposes solutions for addressing them. The draft plan is posted in January, followed by the fourth and final stakeholder meeting and comment period. The draft plan goes to the CAISO Board of Directors for final approval in March.

Figure 8 summarizes the timeline of the CAISO TPP.

Once a transmission plan has been approved by CAISO's Board of Directors, procurement of the identified projects begins. If the plan identified a need for a regional transmission project, CAISO oversees a competitive bidding process. Any projects not determined to be regional transmission facilities will be assigned to the transmission owner in their respective areas for construction. CAISO defines a regional transmission facility as one that interconnects at greater than 200 kV or that interconnects at less than 200 kV, but includes the service territory of multiple transmission owners and is not an upgrade to an existing transmission facility or built within an existing right-of-way.

In practice, most projects are not regional transmission projects subject to competitive procurement. In CAISO's last five transmission plans, only two regional transmission facilities eligible for competitive procurement have been identified.

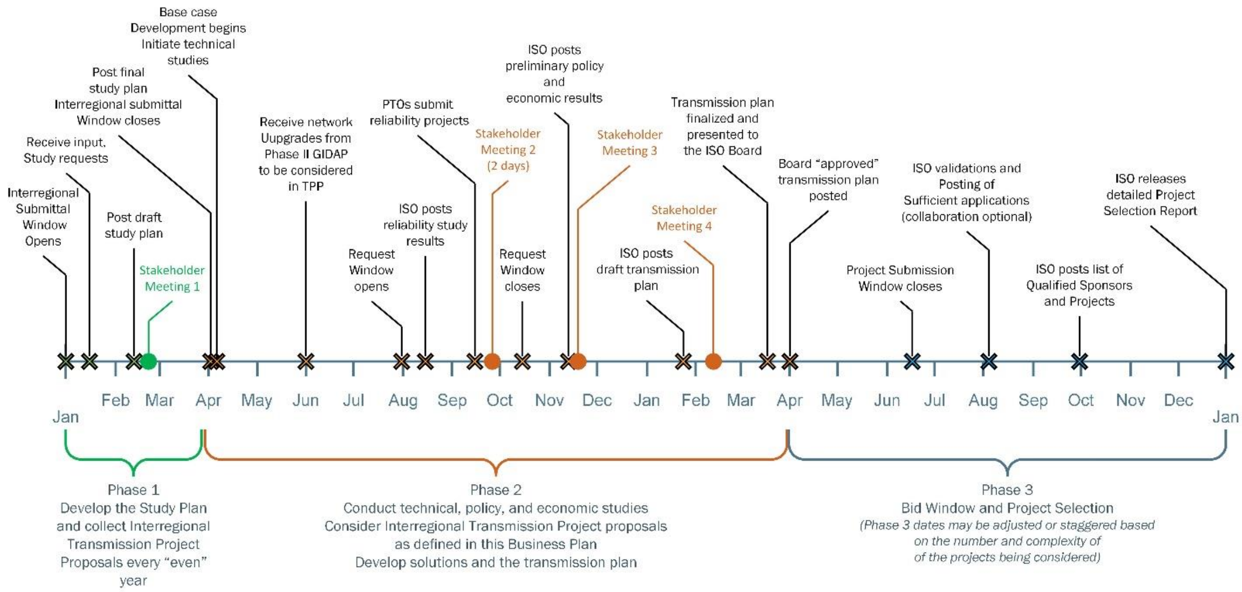


Figure 8: CAISO TPP

In forming the unified planning assumptions at the beginning of a planning cycle, stakeholders can also recommend preferred resources for CAISO to consider in the planning process. Examples of current preferred resources include demand response, energy efficiency, renewable generation, and energy storage. When assessing options for addressing an identified transmission need, CAISO considers the preferred resources first.

CAISO's 2017-2018 Transmission Plan (CAISO 2018a) was the first regional plan to select energy storage as a transmission asset. It selected a 7 MW/28 MWh project to manage thermal overloading on a 115 kV transmission line in the area of Dinuba, CA, over an alternative of reconductoring several miles of the line. CAISO also identified a storage project of at least 10 MW/40 MWh to manage thermal overloading driven by generation retirements in Oakland, CA. The latter project, however, did not involve deploying energy storage as a transmission asset. Rather, it identified the use of a market-facing energy storage project as a means of mitigating the identified thermal loading issue. East Bay Community Energy, the community choice aggregator that serves load in the Oakland area, is competitively procuring energy storage assets that will manage the thermal loading in the area by participating in CAISO's capacity and energy markets.

In the 2020-2021 planning cycle, stakeholders have asked CAISO to continue refining its treatment of energy storage in transmission planning. CPUC's comments on the draft study plan asked CAISO to provide more detail about how it models energy storage as a potential mitigation option. CPUC also indicated that while the state's recently completed integrated resource plan identified 2,000 MW of energy storage, it was still working on a methodology for estimating, at the substation level, where that storage would be deployed. A coalition of municipal utilities in the San Francisco Bay area suggested that CAISO conduct an analysis to determine where those 2,000 MW of storage resources could provide the greatest benefit to the system to better inform future siting decisions.

Pacific Gas & Electric, the utility deploying the two storage projects identified in the 2017-2018 transmission plan, submitted comments indicating that the Dinuba project has already been revised upward from 7 MW to 12 MW based on changing needs. They suggested that when considering storage as a transmission asset or mitigation option, CAISO apply a margin when estimating the size and cost of the storage necessary to satisfy the identified need.

A.2 Independent System Operator of New England

ISO-NE manages the electric grid in the New England region, which includes Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and most of Maine. Every two years ISO-NE issues a Regional System Plan, which incorporates the ISO's TPP and covers a ten-year planning horizon. The Regional System Plan includes a regional forecast of energy and supply as well as other studies relevant to current system conditions. It also identifies needed transmission projects, categorizing these projects into reliability transmission upgrades, market efficiency transmission upgrades, public policy transmission upgrades, elective transmission upgrades, and upgrades associated with generation interconnection.

Transmission reliability projects must address system needs three or fewer years into the future. ISO-NE frequently conducts needs assessments to evaluate the ability of its networked transmission facilities to maintain reliability. These assessments are triggered by several technical factors and are conducted by ISO-NE with review and feedback from system stakeholders. Although a needs assessment is intended to address a transmission reliability upgrade, it incorporates an analysis of potential market solutions, including resources (such as energy storage or distributed energy resources) and elective transmission upgrades. If an assessment identifies a reliability-driven transmission need that is at a voltage of 115 kV and above must be met in three years or less, ISO-NE conducts a solutions study to identify the most cost-effective transmission system upgrades that will address the identified needs. In addition, ISO-NE develops transmission solution alternatives with the input of transmission owners and its stakeholder Planning Advisory Committee and selects the most cost-effective option to meet the identified needs. The costs of these reliability upgrade projects are eligible to be allocated regionally.

Alternatively, if an identified reliability transmission need does not need to be met in less than three years, ISO-NE will conduct the competitive solutions process. This process works to select a project from a Qualified Transmission Project Sponsor, regardless of whether they are the incumbent operator of the transmission system that has the need. This approach is also eligible for regional cost allocation.

As part of the Regional System Plan, ISO-NE also conducts an annual economic study process, driven either by high network congestion costs or a desire to increase access to a future generation source through a stakeholder process. The studies evaluate reductions in generation production cost relative to the cost of a transmission solution. ISO-NE also conducts three economic studies each year that have been identified by the stakeholder community. These studies identify different proposed transmission and resource expansion scenarios and determine their potential value and costs to inform regional stakeholders, including regulators and policymakers. These studies rely on assumptions provided by stakeholders. If the study process identifies a justified transmission solution, the ISO conducts another study using its own assumptions. If this secondary study also identifies a transmission expansion, the ISO conducts a two-phase competitive process to select a project and a Qualified Transmission Project Sponsor. This project is designated a market efficiency transmission upgrade and is eligible to receive regional cost allocations. Stakeholders may also request that ISO-NE conduct economic studies that include evaluation metrics beyond economics, for example emissions metrics.

To study the need for public policy-driven transmission projects, ISO-NE relies on the New England State Committee on Electricity for guidance. Upon identification of a state or regional energy policy that may require additional transmission infrastructure, ISO-NE evaluates whether current transmission investment efforts (i.e., the other transmission upgrade approaches) will meet this need. If not, the ISO will conduct a competitive solicitation process to identify a Qualified Transmission Project Sponsor and permit regional cost allocation for the project.

Finally, transmission developers may also propose and develop participant-funded elective transmission projects. These projects are outside of the needs assessment and economic studies processes and are therefore not subject to regional cost allocation. These projects may be energy storage resources.

As part of ISO-NE's cost effectiveness and cost allocation of identified reliability and market efficiency upgrades, both the planning and stakeholder review processes include an examination of transmission upgrade alternatives to meet the identified transmission needs, including energy storage technologies. This effort evaluates the costs and thus the cost effectiveness of each transmission upgrade and its potential alternatives. The determination of alternatives for evaluation is subject to its own planning and stakeholder review from the Planning Advisory Committee.

A.3 Midcontinent Independent System Operator (MISO)

The MTEP is a 10-year plan formulated through a 24-month process. Cycles overlap by a full year so that a plan is completed every year to comply with NERC TPL-001-5. Cycles begin every January and conclude in January two years later.

Conceptually, MISO defines the MTEP in terms of three functions: a bottom-up function, which includes reliability-driven and non-reliability-driven projects identified through a transmission owner's local planning process; a top-down function, which includes market efficiency (economic) projects and multi-value projects; and an externally driven function, which includes generation interconnection projects, long-term transmission service projects, participant-funded projects, and interregional projects. Public policy projects in MISO are studied in the local planning processes of individual transmission owners.

Stakeholder participation in the MTEP process is facilitated through three mechanisms: sub-regional planning meetings, which are divided into four regions (North, Central, East, and South) and give stakeholders an opportunity to review bottom-up studies; the Planning Subcommittee, which provides feedback on top-down studies; and the Planning Advisory Committee, which assists in the development of the MTEP's planning assumptions. Sub-regional planning meetings are held three times a year, while the Planning Subcommittee meets seven times a year and the Planning Advisory Committee meets quarterly.

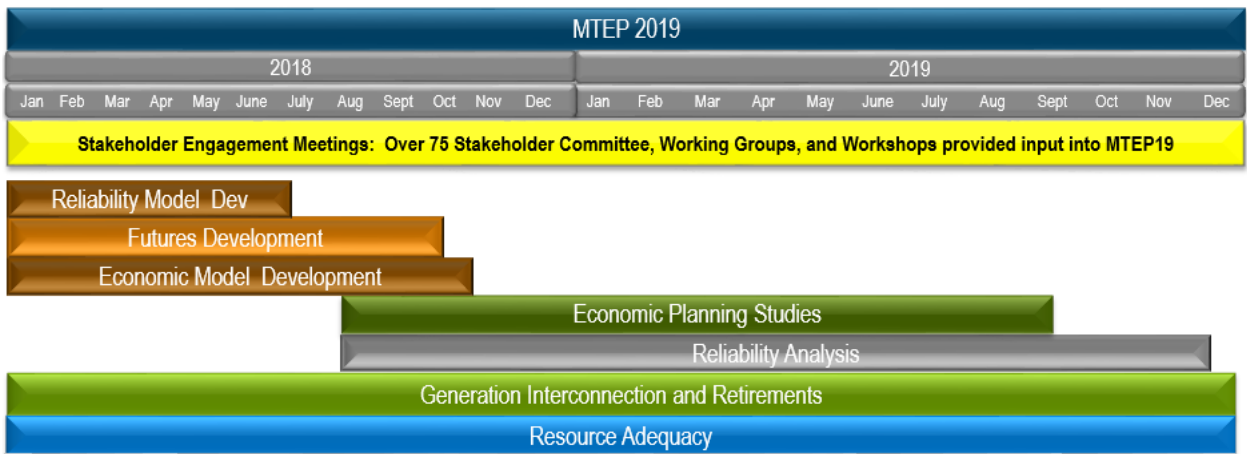
Structurally, each MTEP cycle conducts the bottom-up analysis first. It begins with MISO working with the Planning Advisory Committee to develop assumptions related to what the grid will look like in five years and requesting planning information from its member transmission owners, which have independently prepared their own local transmission plans. The local plans are treated as inputs into the regional plan.

The process of formulating assumptions, collecting local planning information, and defining the scope of the analyses that will be conducted in the cycle lasts from January until July or August. During this period, MISO also identifies market efficiency studies and accepts recommendations for such studies from transmission owners and stakeholders.

Once all the necessary inputs have been gathered, MISO conducts reliability and economic analyses concurrently. At the conclusion of the analyses, usually early the following year, MISO presents all identified needs to the Planning Subcommittee. In consultation with transmission owners, MISO conducts a preliminary review of the identified needs and flags those which cannot be viably addressed through a non-transmission project. For all non-flagged projects, stakeholders may request MISO to further analyze the need to determine the type and size of non-transmission alternatives that would be required to address it.

MISO takes all of this feedback and identifies a preferred solution for each need, then submits the preferred solution for stakeholder review and comment. By September, a draft MTEP is prepared and submitted for stakeholder review, and the MTEP is submitted to the MISO Board of Directors for final approval at its December meeting.

Figure 9 summarizes the process for the 2019 MTEP.



MISO

Figure 9: Overview of MISO's MTEP Process

MISO recently concluded an extensive stakeholder process to explore the role of energy storage in transmission and dual-use applications. The process culminated in a tariff filing that creates a new asset class (SATOA). FERC accepted the tariff, which allows an energy storage device that is selected as a transmission asset to forego the interconnection queue and any network upgrade costs but prohibits it from participating in MISO's energy markets.

MISO selected its first SATOA project in the 2019 MTEP, a 2.5 MW/5 MWh battery deployed on a 69 kV system near Waupaca, WI. The device will serve to maintain local reliability during maintenance and unplanned outages.

A.4 New York Independent System Operator

The New York Independent System Operator (NYISO) operates the high-voltage power system, administers the wholesale power market, and conducts system planning for the state of New York. With regards to transmission, NYISO conducts planning studies that identify transmission reliability needs, congested areas within the state, and potential solutions to public policy transmission needs. Market transmission participation is informed by identification of congested areas, which leads to further study of generic transmission solutions to inform market participants about how they may address this congestion through transmission or other projects.

Unlike other ISOs and RTOs, NYISO has not selected a transmission project for regional cost allocation since its inception in 2014. Market-based solutions or other market changes have addressed any identified transmission needs.

NYISO's Comprehensive System Planning Process consists of: (1) local transmission planning, (2) reliability planning, (3) economic planning; and (4) public policy planning as shown in Figure 10.

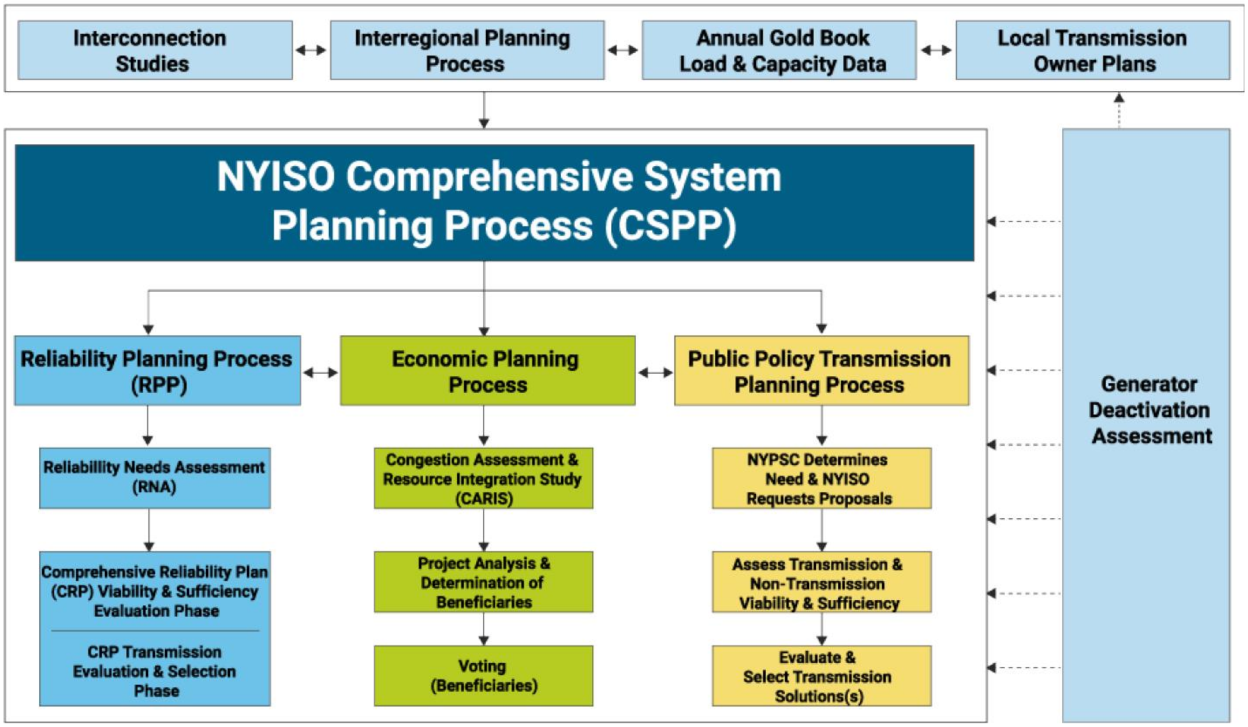


Figure 10. NYISO Comprehensive System Planning Process

Transmission owners within New York conduct their own planning studies for their transmission areas. These studies focus on reliability, generation interconnection, requests for transmission service within the area, and public policy drivers. The study effort develops transmission plans that form the basis for broader scale transmission planning within the state.

NYISO uses a two-phase, two-year cycle for regional reliability planning. In phase 1, NYISO develops a reliability needs assessment, conducting a New York statewide analysis of the overall suitability or adequacy of the local transmission plans submitted by each transmission owner over a 10-year outlook. These plans are evaluated according to NERC Standard TPL-001-5 as well as local reliability rules set by the New York State Reliability Council and reviewed by stakeholders of the Transmission Planning Advisory Subcommittee.

In phase 2, the NYISO develops a comprehensive reliability plan. NYISO requests both market-based and rate-regulated projects from developers that have qualified for the planning process. These projects are not limited to transmission solutions and can include transmission, generation, energy storage, and demand response among other resources that meet the need. NYISO considers the proposed solutions, preferring a market solution to meet the reliability needs assessment. If a market solution meets the need, it is selected; if it does not, NYISO evaluates and selects a rate-regulated solution that is the most cost effective or efficient mechanism to address the identified need. If the market solution is the preferred approach, NYISO will also select an existing transmission owner to develop a rate-regulated “back-stop” solution in case the market solution does not proceed. This comprehensive reliability plan is reviewed by stakeholders and approved by the NYISO board.

Similar to reliability planning, NYISO conducts economic planning in a two-phase, two-year cycle. As part of this effort, it develops a Congestion Assessment and Resource Integration Study that covers the same 10-year time horizon as the reliability needs assessment.

Phase 1 of the study effort identifies the three most congested areas of the state transmission system and prepares a benefit-cost analysis for hypothetical solutions (transmission, generation, energy storage, demand response, or others) that address each congestion area. As with other regional planning processes, this effort is intended to inform potential developers and other stakeholders about the value available to different solutions to address this congestion. Congestion areas are identified based on the five most recent years of transmission flows and operations and 10-year projections. These areas are then ranked by an aggregate congestion value, which is an aggregation of discounted congestion values for each of the constraints in the area, across the planning horizon (10 years plus five years) as well as the constraints' forecasted impacts to overall system production costs. NYSIO identifies the value of relieving the total constraints in each area by comparing production costs for the initial system and a fully unconstrained system. The three areas with the highest potential value of constraint relief are selected for study.

Next, NYISO takes a scenario analysis approach to evaluate four generic solutions to address congestion in each area. These solutions are primarily evaluated on a reduction in system production costs, but other relevant metrics are also considered and evaluated. The four generic solutions consist of generation, transmission, demand response, and energy efficiency.

Phase 2 of the economic planning is initiated if a developer proposes a project to address one of the identified congestion areas. In step one of phase 2, NYISO conducts a benefit-cost analysis of the proposed project, evaluating the project's costs (in the form of revenue requirement) relative to 10-year production cost benefits for the system. If the benefits exceed the costs, step two is initiated. In step two, NYISO establishes the regional cost allocation for the project by evaluating whether the sum of the zonal benefits of the project across the state exceed revenue requirements. Zonal benefits are calculated by considering the change in locational marginal prices that the project has on affected zones relative to the constrained case, subtracting contracts that otherwise are not impacted by the investment. If zonal benefits across the state exceed costs, the project is then submitted for stakeholder review and approval by the NYISO board.

NYISO's public policy transmission planning is conducted in partnership with the New York Public Service Commission (NYPSC), the state energy regulator. NYPSC establishes a transmission need based on public policy requirements it develops and those submitted by stakeholders and the NYISO. Developers then propose solutions to meet this identified need. These solutions are evaluated by NYISO to ensure they are adequate to meet the proposed need and this analysis is reviewed and approved by NYPSC. NYISO will then identify the most efficient or cost-effective solutions to meet the public policy need based on project costs and other metrics as directed by NYPSC.

Each step of the TPP includes the ability for stakeholders to provide input. In addition, the reliability planning process requests proposals for any type of project to meet identified needs. The economic planning process explicitly evaluates alternatives. At any time, market participants and other stakeholders may submit suggestions for changes to NYISO rules or procedures, which could result in the identification of additional resources or market alternatives suitable for meeting reliability needs if stakeholders determine that NYISO's process is not appropriately considering alternatives.

A.5 PJM

PJM's Regional Transmission Expansion Plan (RTEP) consists of two separate planning cycles: an overlapping 18-month cycle that prepares the annual plans required by NERC TPL-001-5 and a longer 24-month cycle, both of which utilize a 15-year planning window. The 18-month cycle focuses on smaller, near-term transmission needs (using a base year set 5 years in the future), while the 24-month cycle focuses on larger long-term needs (using a base case set 8 years in the future, or 7 years by the time the cycle concludes).

The 18-month cycles begin every September and overlaps by six months, so that two shorter planning cycles are completed during each longer planning cycle. Plans are named based on the year in which the analytical work was conducted, not the year in which they were published. For example, PJM published the 2019 RTEP in February 2020 and will publish the 2020 RTEP in early 2021.

Figure 11 summarizes the RTEP cycles (PJM 2019).

The annual RTEP document identifies two basic types of transmission projects: baseline upgrades, identified by PJM to meet network reliability, public policy, or economic needs; and supplemental projects, identified by PJM's member transmission owners for system expansion or improved reliability within their territory or zone. PJM reviews supplemental projects to ensure they will not adversely impact the broader system and presents cleared projects in the RTEP as informational items; they are not approved by the PJM Board of Managers.

Stakeholder participation to the RTEP is facilitated through two mechanisms. The first is the Transmission Expansion Advisory Committee (TEAC), which serves as the venue for stakeholder review of all projects that would connect at 230 kV or higher. The second is a group of three regional committees (Mid-Atlantic, Southern, and Western), which serve as the venue for stakeholder review of all projects that would connect below 230 kV (each regional committee reviews the projects within its region).

Regional committees also review analyses and proposals arising from the State Agreement Approach, a mechanism that allows a state or group of states to request transmission projects to enable public policies and enter into an agreement with PJM to allocate the costs of such projects to the participating state(s).

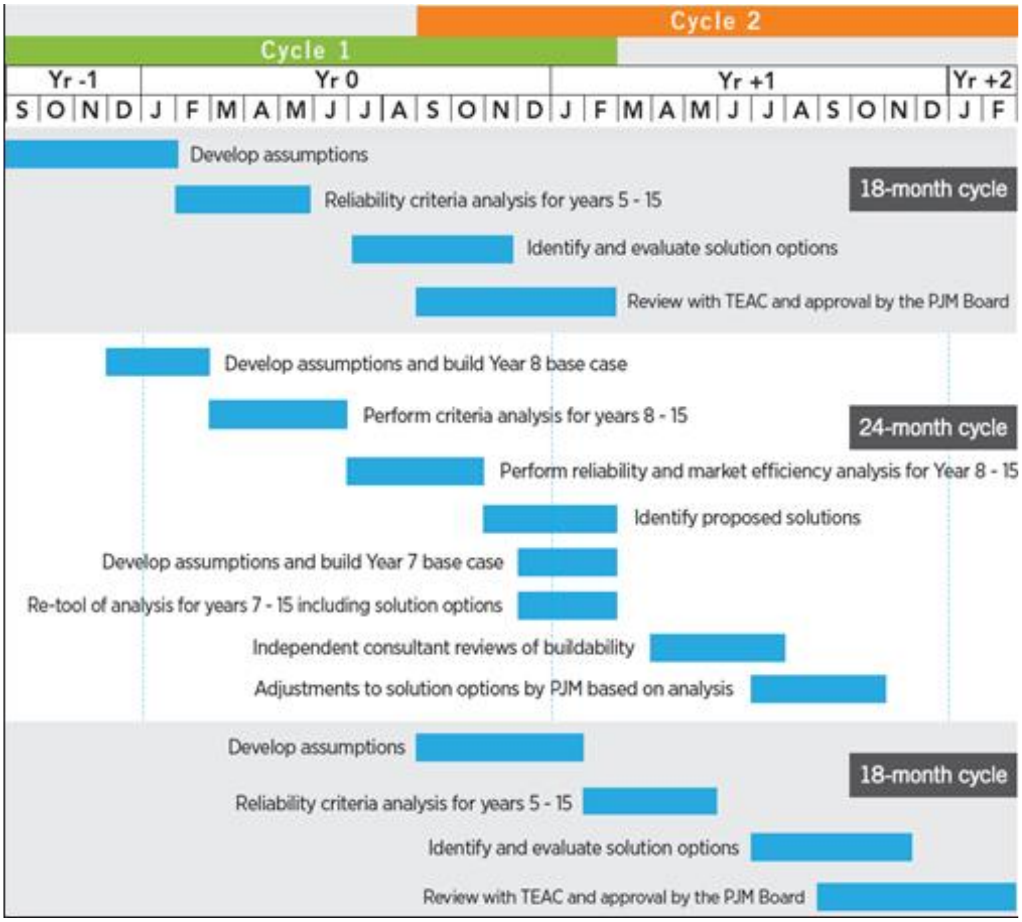


Figure 11: Overview of PJM RTEP Cycles

In practice, each RTEP is a progressive, layered analysis that begins with the required reliability studies and adds in other analyses and projects as follows:

7. Baseline reliability analyses based on the reliability standards set by NERC and regional reliability organization within the PJM footprint
8. Market efficiency analyses (economic projects)
9. Zone-specific analyses based on each participating utility's specific reliability standards and needs, as identified in FERC form 715
10. State Agreement Approach analyses (public policy projects)
11. Supplemental project analyses.

The baseline reliability analysis conducted in the first step effectively serves as RTEP's foundation; projects proposed in subsequent steps are compared against the baseline for need and appropriateness. If the needs identified by a subsequent project are addressed in the baseline analysis, or if the proposed project would negatively impact the broader network, the proposal is withdrawn or amended as necessary. The RTEP also has a mechanism for independently studying proposed projects that would satisfy multiple goals.

The RTEP process has frequent, regular opportunities for stakeholder participation. TEAC holds monthly meetings and the three regional committees also generally meet on a monthly basis.

Planning assumptions for each RTEP cycle are drafted by PJM and presented at the December or January committee meetings. Those informing the regional 245 kV and higher analyses are presented to TEAC and those informing the supplemental and below-245 kV analyses are presented to their respective regional committees. After the meetings, stakeholders are allowed to submit comments and suggest alternative modeling scenarios for PJM to consider. The assumptions are finalized in January and the reliability modeling begins.

Results of the reliability analysis are shared with stakeholder committees as they become available; complete results are available and shared with the committees by July or August. Results are presented in terms of the reliability violations that will exist in the baseline year (2024 for the 2019 plan) under the current planning assumptions. After final results are posted, a two-month proposal window opens in which transmission owners and independent developers can submit proposals to correct the identified system deficiencies.

Only certain issues are eligible for proposals, those representing an immediate need (within the next three years), that would be deployed at 200 kV or less, that are driven by a utility's local reliability standards as identified in FERC Form 715, or that would be deployed within an existing substation are all assigned to the local transmission owner for resolution. Of the 155 reliability issues identified in the 2019 RTEP reliability analysis, 102 were eligible for stakeholder proposals.

Once the reliability analysis is done, PJM conducts additional studies: market efficiency, Form 715, State Agreement Approach, and supplemental projects. Assumptions for these analyses have been submitted for stakeholder review months in advance. The final RTEP document is compiled by December and submitted to the PJM Board of Managers for approval.

Energy storage does not appear to have yet received serious consideration in PJM's RTEP process. The PJM Manual 14B: PJM Regional TPP is the business practice manual that governs the RTEP process. It contains only tangential references to how existing PSH facilities are modeled in PJM's power flow models. The 2019 RTEP does not identify energy storage for meeting any transmission system needs and the research team could not identify an instance in which storage was considered.

The 2019 RTEP refers to an effort that PJM convened in 2019 to better understand the potential role of energy storage in transmission applications and indicates that additional discussions are expected in 2020. PJM does not appear to have created a formal proceeding for the topic, however, and the research team could not find any record of the conversations that have taken place on the topic.

A.6 Southwest Power Pool

SPP's Integrated Transmission Planning (ITP) process is a 24-month, overlapping process that produces an annual 10-year Transmission Expansion Plan in compliance with NERC TPL-001-5. ITP analyses focus on cost effectiveness and flexibility, considering reliability, public policy, operational, and economic drivers while working in concert with SPP's existing sub-regional planning stakeholder processes.

ITP analyses are shaped by a study scope document that contains assumptions and methodologies that will be used during the process. The study scope document is subject to stakeholder review and approval at the outset of every ITP cycle and stakeholders can request modeling of alternate future scenarios.

Stakeholder participation in the ITP process comes through multiple avenues. SPP maintains three technical working groups to review different aspects of the plan: economic studies, transmission, and model development. There are also four stakeholder committees involved in developing the transmission expansion plan: the Seams Steering Committee, which reviews projects for potential interregional collaboration; the Strategic Planning Committee, which provides input into scenario development and policy issues; the Markets and Operations Policy Committee, which reviews the assessment report; and the Regional State Committee, which provides a state-focused review of the assessment report.

SPP also solicits input from stakeholders on combinations of potential economic upgrades that can be evaluated as potential balanced portfolios. Economic upgrades must include a 345 kV or higher facility, but may include a limited amount of lower voltage transmission facilities needed to integrate the 345 kV or higher facilities. Balanced portfolio projects must also include the costs of upgrades needed to relieve congestion on a neighboring system that results from building the potential balanced portfolio.

Once the study scope document is complete and planning models have been updated as necessary, SPP simultaneously conducts its reliability, economic, public policy, and operational assessments of the grid. Economic needs are identified if the analysis determines there is a high-congestion point on the grid that exceeds certain congestion cost metrics. Reliability needs are identified if any contingency analysis identifies a failure to comply with the standards in NERC TPL-001-5. Public policy needs are identified if the analysis finds a grid constraint that would prevent a region from complying with state-imposed resource mix requirements.

Upon completion of the studies, there is a 30-day response window during which any stakeholder may submit a detailed project proposal. After analyzing all submitted projects, SPP makes a comprehensive presentation of the results, including the preferred solution, and solicits feedback from stakeholder working groups. Using this feedback and the results of the cost effectiveness analysis, SPP prepares the annual ITP assessment report, which includes a draft list of projects for review and approval.

Projects approved by the Markets and Operations Policy Committee and SPP Board of Directors at the conclusion of the ITP process will receive a notification to construct letter. After a letter is issued, the project is reviewed annually to make sure it is still needed and on schedule.

The process flow of the ITP assessment is shown in

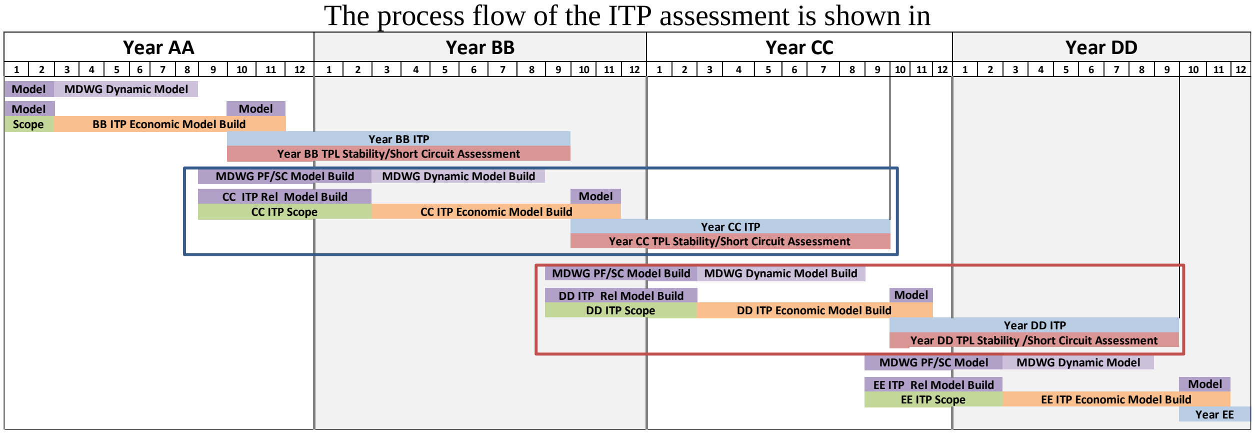


Figure 12 (SPP 2020).

In addition to the annual ITP cycle, SPP conducts an ITP 20-year assessment (ITP20) at least once every five years. The ITP20 is focused on planning for the highest voltage lines (300 kV and above) for a 20-year horizon. The purpose of the ITP20 is to design a backbone high-voltage transmission system for the region. SPP, along with its stakeholders, develops the scope of the ITP20. The final report identifies projects that meet design criteria for reliability, economic feasibility, and public policy. The ITP20 informs other assessments but does not necessarily lead to project construction approval by itself.

While the SPP transmission planning approach provides ample opportunity for new projects to be proposed, energy storage is rarely mentioned in any of its planning documents. SPP's Integrated Transmission Planning Manual only briefly mentions energy storage in the context of power flow modeling assumptions, and the manual's definition of non-transmission alternatives only discusses changing set points of the existing system or adding generation resources.

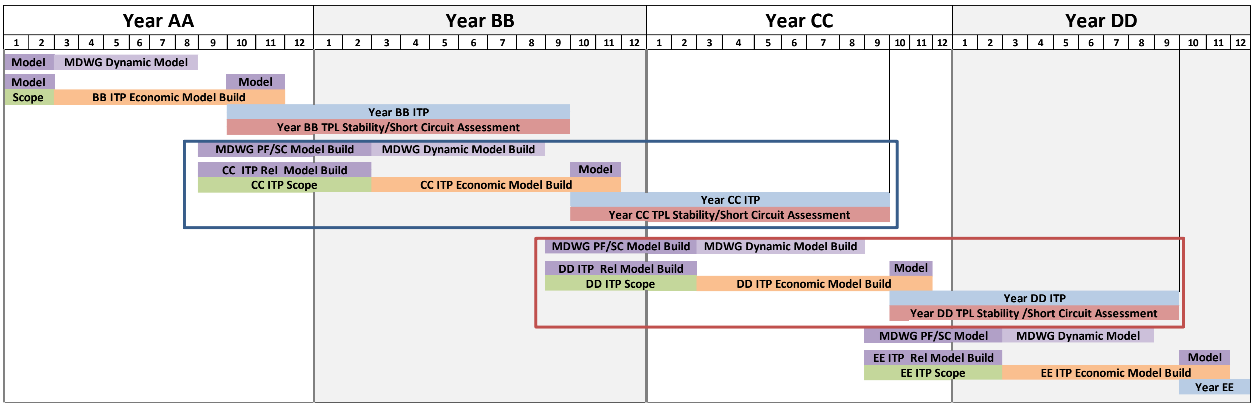


Figure 12: SPP's Integrated TPP

Though developers proposed energy storage projects during SPP's 2019 ITP process, those projects were not selected and storage has not yet been deployed as a transmission asset in SPP.

SPP issued a report in 2020 outlining the potential for energy storage in SPP as a generation asset, as a transmission asset, and as a dual-use asset. The report also identified some of the regulatory and modeling challenges that would limit realization of those benefits (SPP 2020). SPP created an Electric Storage Resources Committee to develop proposals for addressing those issues. At the time this report was published, the committee was working on drafting regulations for energy storage as a transmission-only asset, patterned after MISO's SATOA policy.

A.7 Non-ISO Planning Regions

A.7.1 NorthernGrid

NorthernGrid was formed as the combination of ColumbiaGrid and Northern Tier Transmission Group in early 2020 to allow for collaborative planning by the two regions on a single timeline. The NorthernGrid TPP will follow a two-year cycle and "provide meaningful opportunities for stakeholders to participate in the planning process."

Across the two-year cycle, the TPP involves multiple stages. The first stage is data gathering, which involves taking information from local transmission planning, prior regional plans, WECC cases, alternative projects, and other assumptions and data.

In stage two, the collected data is developed into a study scope. This process evaluates committed projects, baseline projects, alternative projects, non-transmission alternatives, and other considerations. Once developed, it is given to the Enrolled Parties and State Committee as well as members/stakeholders for review and comments. During this review procedure, stakeholders may submit additional projects for consideration and the study scope is eventually finalized. The execution of this study scope involves performing technical studies and leads to the development of the draft regional transmission plan.

In the draft final regional transmission plan, updates to the study scope are made if necessary, additional studies are performed as needed, and the draft regional plan is updated with stakeholder comments. The draft plan is sent to the same parties as before for review and comment. Once all comments have been addressed, the final plan is published.

The timeline of the steps outlined above is shown in Figure 13.

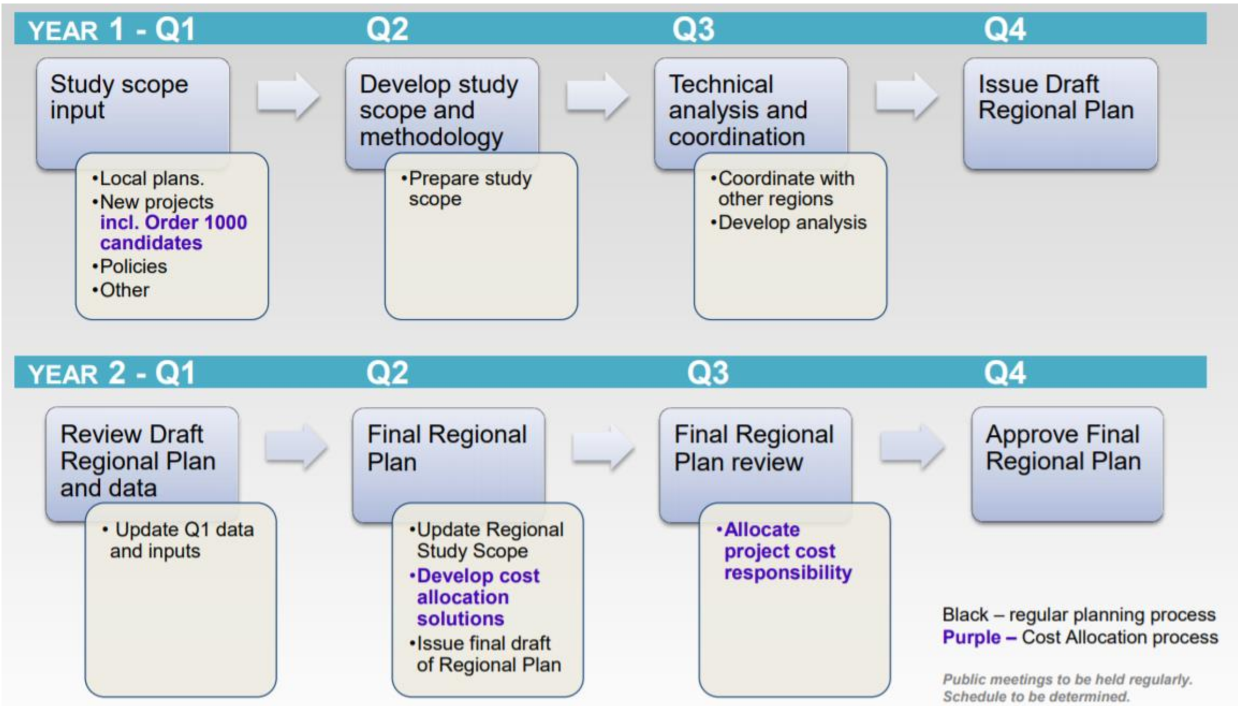


Figure 13: Timeline of NorthernGrid Planning Process

NorthernGrid aims to facilitate state involvement by having a representative from each participating state as a member of the State Engagement and Cost Allocation Committee. Neither of the most recent transmission plans for ColumbiaGrid and the Northern Tier Transmission Group contain information regarding the consideration of storage or alternative assets.

A.7.2 WestConnect

The TPP for WestConnect follows seven steps across a two-year planning cycle, as shown in Figure 14.

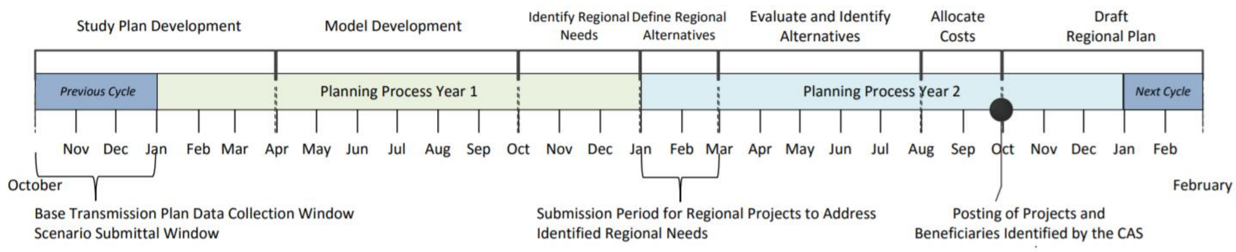


Figure 14: Timeline of WestConnect Transmission Planning Process

The process begins with development of the WestConnect regional study plan that is ultimately presented to and approved by the Planning Management Committee (PMC). The PMC includes five member sectors: (1) transmission owners with load serving obligations; (2) transmission customers; (3) independent transmission developers or owners; (4) state regulatory commissions; and (5) key interest groups. The PMC ultimately has authority over the regional transmission plan. The aim of the study plan is to examine the scope and timeline of study work that will be conducted throughout the planning cycle. This could include evaluation of necessary power flow and production cost modeling, planning data and assumptions (e.g., demand forecasts, additions or retirements to generation, infrastructure changes), public policy requirements, responses to WECC transmission expansion analyses that apply to the WestConnect region, and other considerations.

The base transmission plan developed from this process is later used to model the transmission network in the power flow and production cost modeling studies in order to identify the needs of the region. At this stage the base transmission plan includes planned projects developed by transmission owners with load-serving obligations and other projects such as those chosen for cost allocation or outlined in previous planning cycles. All projects included in the plan outline the regional transmission projects and non-transmission alternatives that can satisfy regional needs. Ultimately, the PMC reserves the right to exclude projects in their final review.

Once the final study plan is complete, during quarters 2 and 3 of the planning process, the power flow and production cost modeling is performed. These are completed to carry out the technical studies outlined in the study plan. Production cost modeling is used to examine whether there are projects available that can reduce the total delivered cost of energy through congestion alleviation or through other economic benefits to the system.

During quarter 4 of the planning process, the system is evaluated to determine transmission needs. WestConnect works with members and stakeholders during this stage to perform a reliability assessment using power flow analysis and production cost modeling to determine the economic assessment. At this stage, public policy (e.g., renewable portfolio standards, distributed generation standards) are considered as well. The findings of regional needs are shared with stakeholders at the end of the process.

Step five of the planning process involves consideration of alternative projects to meet regional transmission needs. Any active member can submit projects to be considered. This includes transmission projects that both are and are not seeking cost allocation as well as non-transmission alternatives. Qualified projects must be submitted with various data items including cost estimates, location of project, facilities required, independent studies required, an explanation regarding cost effectiveness, and other considerations.

Non-transmission alternatives, which could include distributed generation, load management programs, energy storage, and smart grid equipment, are considered in the rollup of local utility transmission plans into the regional plan or as alternatives to regional needs. Local utilities evaluate these resources in their integrated resource and transmission plans and their plans are brought into the WestConnect regional plan. WestConnect evaluates non-transmission alternatives on the bases of their relative cost, risks, reliability impact, construction timelines, and benefits.

In the sixth and seventh quarters of the planning process, the projects identified in the models and studies are examined to determine if they resolve the identified needs. The models and studies must determine if the regional projects submitted due to cost effectiveness impose any reliability risks or generate any new economic or public policy needs. Projects are selected from competing solutions to determine the overall combination of projects that satisfy needs.

Allocation of costs is exercised on projects determined to be more cost effective and pass the regional cost allocation benefit-cost threshold of 1.25. The allocation procedure distributes costs to transmission owners with a load-serving obligation for improvements to system reliability only when it is required to comply with NERC standards. The cost of projects that affect at least two members of WestConnect will be determined by the relative benefit that each receives.

During the final quarter of the planning cycle, and after stakeholder input has been collected, the PMC votes on the approval of the regional plan. The regional plan is continuously reevaluated to ensure that the selected projects are consistently the most efficient or cost-effective options to meet needs.

A.7.3 Energy Storage in the WestConnect TPP

Within its Regional Planning Business Practice Manual, WestConnect includes information regarding non-transmission alternatives that can be suggested within the TPP. Non-transmission alternatives are defined as “technologies that defer or possibly eliminate the need for new and/or upgraded transmission line.” The technologies that qualify include distributed generation resources, demand-side management such as demand response or energy efficiency, energy storage facilities, and smart grid equipment.

The two most recent planning cycles did not appear to reveal any storage projects to be considered as transmission.

A.7.4 Southeastern Regional Transmission Planning

The regional plan for Southeastern Regional Transmission Planning (SERTP) is developed on an annual basis and is a result of the combined local transmission plans of the utilities that participate in the regional group. The sponsors within the SERTP group each develop regional models that are ultimately coordinated together to develop an SERTP transmission plan. The models contain the most up to date transmission planning information within their specific area. Each of the individual sponsors plan their transmission system as needed to reliably and economically meet future load, public policy requirements, and other commitments. Each sponsor identifies and implements their transmission expansion options in order to deliver long-term service. A majority of the long-term transmission commitments in the SERTP come from Load Serving Entities (LSEs). The decisions made by LSEs and the corresponding commitments are passed along to the SERTP sponsors. These form the basis of the transmission planning assumptions in the region. LSEs identify resources that are outlined in their integrated resource planning processes as the most suitable to serve their customer’s needs. The load forecasts, demand-side programs, decisions on resources, and transmission commitments make up the majority of the obligations and modeling inputs for the SERTP region transmission planning. As LSEs update their needs for delivery and pass it on to the sponsors, these changes are incorporated into the most recent transmission planning models and analyses.

Transmission projects included as planned projects are reassessed and potentially retimed or removed from the transmission plan for various reasons. Given that the transmission plan is updated on a recurring basis, the SERTP is able to identify new cost-effective options and the removal of projects from their overarching ten-year plan. The SERTP sponsors work to identify regional alternatives to replace local transmission projects as necessary.

The SERTP region's process is intended to interact cleanly with integrated resource planning of the LSE's involved. When decisions are made in the planning process, the expected impacts on the transmission system are reflected in the regional plan unless an alternative and more cost-effective solution has been identified. The decisions by non-LSE participants are also considered and brought into the regional plan as well. For this reason, the regional transmission plan is constantly adapting.

The yearly regional plan is intended to reflect current needs in time and current assumptions and forecasts. If new reliability constraints are identified, sponsors work together to address them through cost-effective methods. Overall, the TPP is considered to be continuously evolving and iterative as demonstrated in Figure 15.

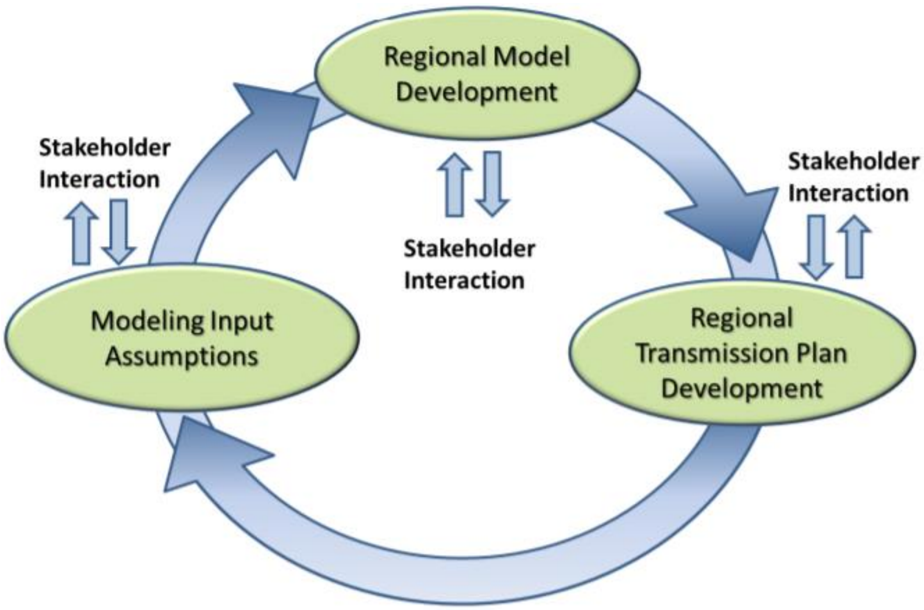


Figure 15: SERTP's Iterative Planning Process

Throughout the iterative process, current plans are re-assessed for need, timing, and potential alternatives. Figure 16 shows the timeline of the TPP across each quarter.

Regional power flow models are developed annually using coordinated inputs and assumptions. These models are intended to provide representations of the existing transmission structure and forecast changes across a ten-year horizon. They also incorporate assumptions brought forth by the LSEs and other transmission customers.

SERTP performs economic planning studies to inform market participants that might suggest alternative projects. The process involves establishing a baseline from the LSE transmission plans and evaluating alternatives proposed. SERTP conducts studies to analyze costs to accommodate the suggestions by stakeholders. SERTP also considers the cost of hypothetical regional projects to the costs considered in the baseline regional plan that they may replace. The overarching purpose of the economic planning studies is to inform stakeholders and developers. SERTP primarily considers avoided transmission costs and changes in transmission losses in evaluating the economic impacts of options in their planning studies.

Diagram II.2: SERTP Process – Quarters 1 & 2

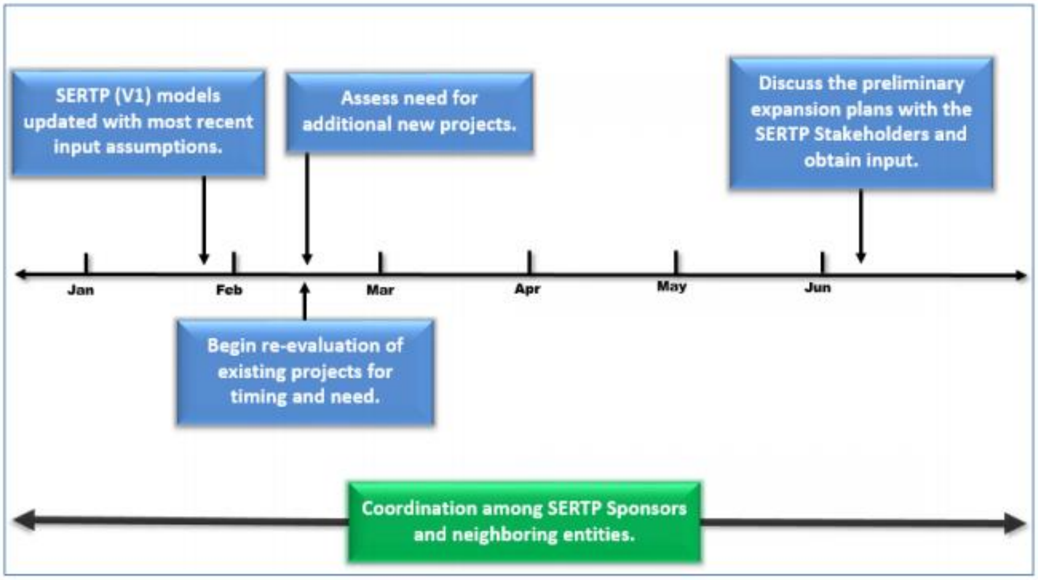


Diagram II.3: SERTP Process – Quarters 3 & 4

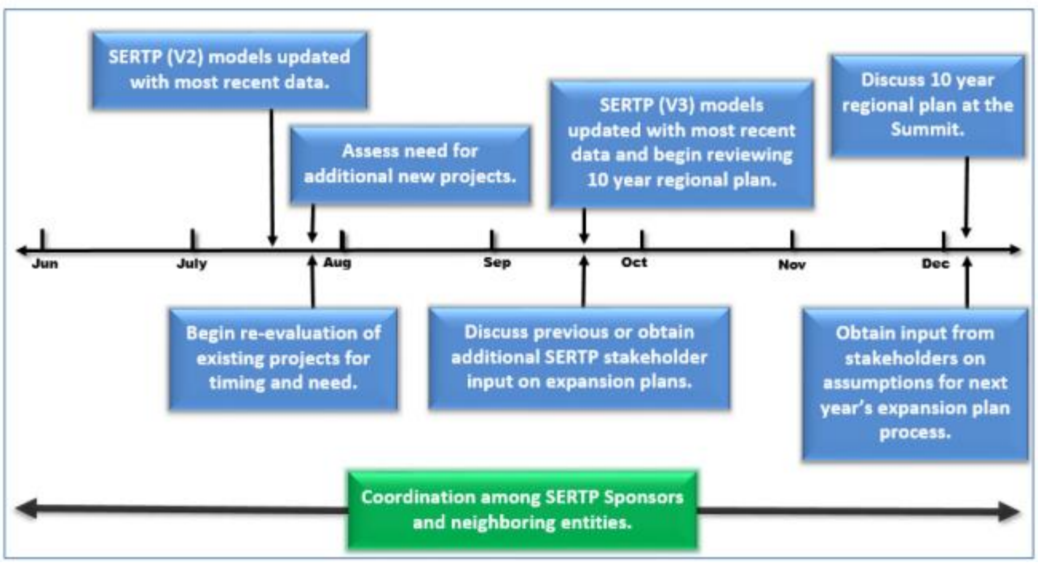


Figure 16: Timeline of SERTP Process

A.7.5 Energy Storage in the SERTP TPP

Energy storage does not appear to be mentioned explicitly within the documentation for transmission planning for the SERTP region. As the regional plan is continuously updated however, alternative transmission options may be suggested. In most cases, storage introduced to the region would likely come through the integrated resource planning process from the LSEs involved. In the 2018 regional transmission plan analyses, three potential alternative transmission projects were considered, but none of them were storage.

This report is being prepared for the U.S. Department of Energy (DOE). As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for fiscal year 2001 (public law 106-554) and information quality guidelines issued by DOE. Though this report does not constitute "influential" information, as that term is defined in DOE's information quality guidelines or the Office of Management and Budget's Information Quality Bulletin for Peer Review, the study was reviewed both internally and externally prior to publication.

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