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Regulatory Implications of Embedded Grid Energy Storage

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U.S. DEPARTMENT OF ENERGY

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Executive Summary

Electricity is unique among commodities in that its supply chain was developed without a storage component. Every other resource commodity has the ability to store excess quantities built into its supply chain – in the form of granaries, warehouses, reservoirs, etc. This embedded storage creates a buffer for mismatches between supply and demand, stabilizing prices and protecting customers.

The lack of embedded storage on the electric grid has ramifications for its design, operations, and costs. Without a buffer, electric grid operators must maintain generation (supply) and customer load (demand) in constant balance – a responsibility that requires constant precision with very little margin for error. To account for unpredictability in loads, generation, weather, and mechanical outages, operators must maintain significant amounts of reserve generation that can quickly respond to changing grid conditions and preserve the balance. It also means that grid components must be sized and built based on peak demand, resulting in a grid that is larger (and more expensive) than what average load would require. When contrasted with the natural gas system, which has ubiquitous storage built into its delivery system, the benefits of embedded storage become clear.

Recent advances in flexible and scalable electrical energy storage technologies have made the concept of embedded storage on the electric grid feasible, but complex regulatory issues must be resolved before it can be practical. The U.S. energy regulatory structure, which bifurcates authority between federal and state levels, has resulted in a fragmented approach to grid planning, involving multiple processes subject to different jurisdictions, each of which considers different grid functions under different time horizons.

This regulatory structure also creates two classes of resources: regulated assets subject to fixed rates set by regulators, and competitive assets subject to market rates. Transmission and distribution assets, the electric grid's delivery infrastructure, are almost universally regulated assets subject to fixed-rate recovery. As a grid asset used to manage the flow and delivery of power, embedded storage would most likely fall into the category of a regulated asset, identified through a regional transmission planning process or a single utility's distribution planning process and subject to fixed-cost recovery.

But before embedded storage can fit within this regulatory paradigm, five key issues must be resolved: the lack of underlying standards, barriers in planning processes, ownership model, compensation structure, and metrics.

The lack of underlying standards for embedded storage is a core challenge that directly or indirectly affects every other challenge. Absent reliability standards that identify the value of embedded storage and establish its role in grid operations, planning models can't identify the need for it, which means that utilities and project developers can't justify investments to regulators or investors.

There are two potential pathways to create opportunities for embedded storage to be deployed on the grid. The first is an incremental pathway, in which regulators establish requirements or guidelines for how embedded storage should be analyzed within existing planning frameworks. The second is a more complex pathway that involves amending existing reliability standards or developing a new standard to establish storage as an integral function of the bulk power system. Regardless of the pathway, quantifying the impacts of embedded storage and

identifying optimal locations for siting it would require coordination across multiple grid planning and modeling processes in order to capture impacts on bulk power system flows, generation and ancillary service needs, and distribution system flows.

Beyond the regulatory issues identified in this paper, several questions remain relating to how the impacts of embedded storage would be quantified and valued. These questions include developing metrics for measuring embedded storage, determining the performance characteristics that storage assets would need to meet to be embedded in the grid, and quantifying impacts on reserve and ancillary service requirements.

These questions will be explored in a subsequent paper in this series, which will discuss the valuation of embedded storage. Development of a pilot project to test the value and impact of embedded storage may provide valuable insight into these questions, particularly if the pilot project is deployed on the seam of a transmission and distribution system that are under the operational control of different entities, so that the impact on balancing needs at both levels is clear.

Acknowledgments

This work was funded by the U.S. Department of Energy's Office of Electricity. The authors also appreciate the guidance of Joe Paladino in the technical direction and focus of this project.

Acronyms and Abbreviations

CAISO	California Independent System Operator
DG	Distributed generation
DSO	Distribution system operator
EIA	Energy Information Administration
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
Hz	Hertz
ISO	Independent system operator
ISO-NE	ISO New England
MISO	Midcontinent ISO
NERC	North American Electric Reliability Corporation
PSH	Pumped storage hydro
RTO	Regional transmission organization
WECC	Western Electric Coordinating Council

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1.0 Introduction

This is the second in a series of papers exploring the concept of embedded energy storage in the electric grid. The first paper introduced this idea as an expansion of how energy storage assets are currently used on the grid – as marginal additions to improve grid flexibility through energy arbitrage and other ancillary services – to also “embed” storage in the architecture of the grid, similar to a substation or a transformer (O’Neil, Becker-Dippmann, and Taft 2019).

This approach, the paper suggested, would unlock value for all grid users by adding the “shock absorber” that we take for granted in other commodities, but has not been possible with electricity until recent advances in energy storage technologies. Absent such shock absorbers, the electric grid operates in a “brittle” state, with grid operators having to constantly maintain a real-time balance between electric supply and demand (*Id).* Maintaining such a balance, while a fundamental physical condition of grid operation, requires oversizing systems to accommodate the greatest possible demand; assuring other resources are available and online to react to a variety of changes in demand (and now, in supply); governance structures to ensure the secure transfers across interconnected systems; and paying extensive costs to maintain the system in this way. In principle, adding the “springiness” and flexibility through embedded storage would decouple supply and demand, and thus would allow us to reshape grid operation toward a more resilient and less costly electric system.

The objective of this paper is to identify the regulatory questions raised by the concept of embedded storage and explore potential pathways forward. The remainder of this section will describe the basics of grid operations and how embedded energy storage could improve them by providing contrasting examples of how embedded storage has benefitted the natural gas system.

Section 2 provides an overview of energy regulatory structures in the U.S. and discusses the questions that embedded storage raises within those structures. Section 3 suggests possible regulatory pathways for embedding energy storage, and Section 4 identifies possible next steps and potential future research opportunities.

1.1 Electric Grid Fundamentals

The U.S. electric grid operates on an alternating current (AC) at a frequency of 60 hertz (Hz), meaning that the current continuously changes direction (moving away from or back toward the generator), completing 60 full cycles every second, as shown in Figure 1 (right).

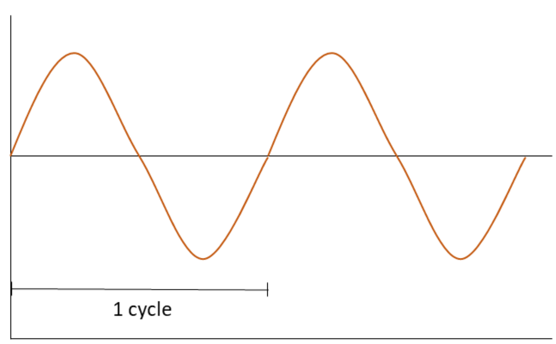
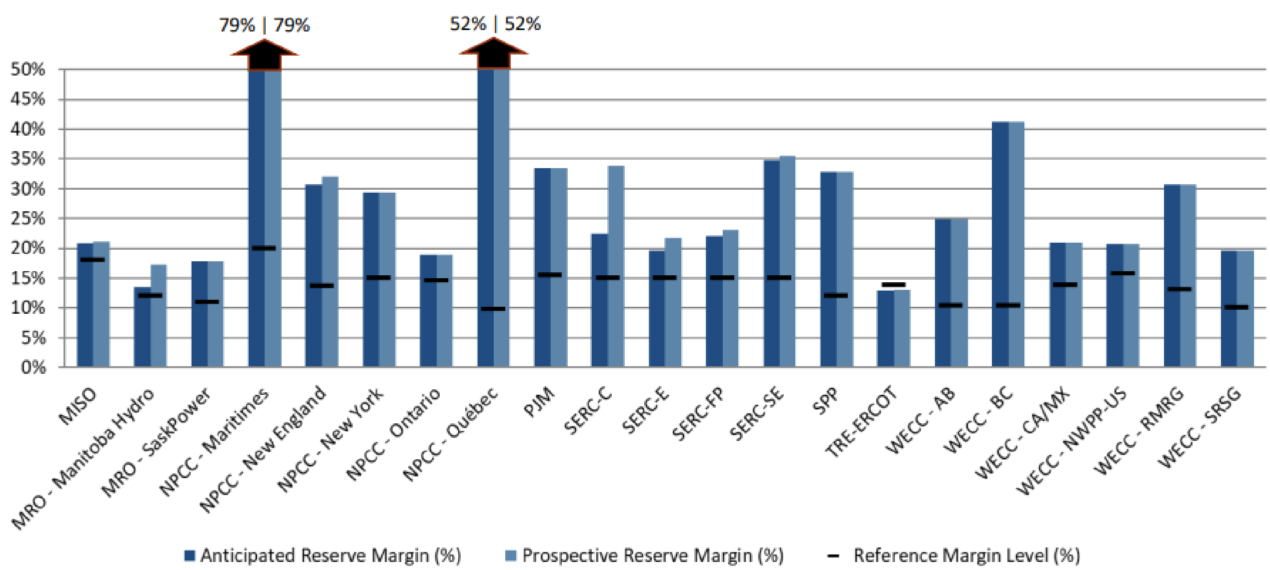


Figure 1. An alternating current cycle

Frequency is an important indicator of the health of the grid, as it measures the balance between generation resources on the grid (supply) and customer loads (demand). If there is more generation than load, frequency increases, and if there is more load than generation, frequency decreases. In the U.S., grid infrastructure and electric motors are designed to function at 60 Hz, and even the smallest variances can damage equipment. To protect that equipment, a primary function of electric grid operators is to keep generation and load in balance, indicated by a frequency of 60 Hz.

Maintaining that balance is a complex exercise fraught with uncertainty. The growing penetration of variable generators makes supply increasingly unpredictable, while customer adoption of new technologies such as distributed generation (DG) and electric vehicles (EVs) has the same effect on demand. Additionally, mechanical failure or inclement weather could force generators or power lines offline at any time. To manage all of that uncertainty and ensure their ability to maintain balance, grid operators carry significant amounts of backup generation, known as a reserve margin, that can come online and support the grid when needed. Figure 2 shows the anticipated reserve margin (the expected level based on then-existing resource availability) and prospective reserve margin (the potential level if planned or out-of-service resources became available) for various North American regions in Summer 2020:



NERC 2020a

Figure 2. Anticipated and prospective reserve margins by NERC Region, Summer 2020

As Figure 2 shows, every region except one was above its reference margin level, which is the region's internal assessment of the reserve level necessary to ensure reliable service throughout the season, accounting for various contingencies. In several regions, the reserve margin is anticipated to be much higher than what has been identified as necessary.[1] That represents gigawatts of generation that have been built to act as a buffer for the grid by providing the necessary flexibility to keep constantly fluctuating supply and demand in balance – at significant cost.

[1] Some of the regions in Figure 2 have a winter peak, meaning that they would have a relatively higher reserve margin level for a summer season.

1.2 Embedded Storage in the Natural Gas Industry

In this respect, electricity is fundamentally different from other energy commodities, which have built-in flexibility in the form of embedded storage. To understand the contrast between a system with embedded storage and a system that lacks it, it is helpful to compare the electric grid with the only other energy commodity that has a delivery system of comparable scope – natural gas. The difference in how the two commodities make use of embedded storage is explicitly captured in the uniform systems of accounts adopted by the Federal Energy Regulatory Commission (FERC) for electric and natural gas utilities. FERC created these accounts to serve as an industry standard for tracking utility expenditures for ratemaking purposes, and their structures illustrate an important difference between the electric and gas industries, as shown in Table 1:

Uniform System of Accounts for Electric	Uniform System of Accounts for Gas
Intangible Plant	Intangible Plant
Production Plant	Production Plant
Transmission Plant	Natural Gas Storage and Processing Plant
Distribution Plant	Transmission Plant
Regional Transmission and Market Operation Plant	Distribution Plant
General Plant	General Plant

Table 1. FERC's Uniform Systems of Accounts for Electric and Gas Industries

The accounting systems for electric and gas industries follow the same basic structure, with one notable difference in each industry. For natural gas, that difference is the inclusion of storage as core infrastructure in utility operations and ratemaking. Storage is in the DNA of the natural gas system; an integral function that can be taken for granted, but which has created sizeable benefits for the industry and its customers. To understand just how transformational the role of embedded storage has been in the natural gas industry, it is helpful to compare it with the electric industry.

The U.S. has the ability to store more than 9.2 trillion cubic feet of natural gas on a long-term basis (EIA 2020a), nearly one-third of the 31 trillion cubic feet that the U.S. consumed in 2019 (EIA 2020b). This capability results in three critical benefits for the industry and its customers.

First, storage allows gas providers to reduce price volatility by building up reserves ahead of seasonal and daily peaks. By November 2019, the U.S. had almost 8 trillion cubic feet of natural gas in long-term storage, enough to meet all U.S. demand for more than two months during the winter season (EIA 2020a; EIA 2020b). Not only does this allow for more reliable supply when it is most needed, it also protects customers from price spikes by allowing utilities to buy low-cost gas during periods of low demand and store it for use during high-demand (and therefore high-cost) periods. To manage daily demand cycles, local gas distribution companies may also pre-pressurize distribution lines with additional quantities of gas in advance of high-demand periods.

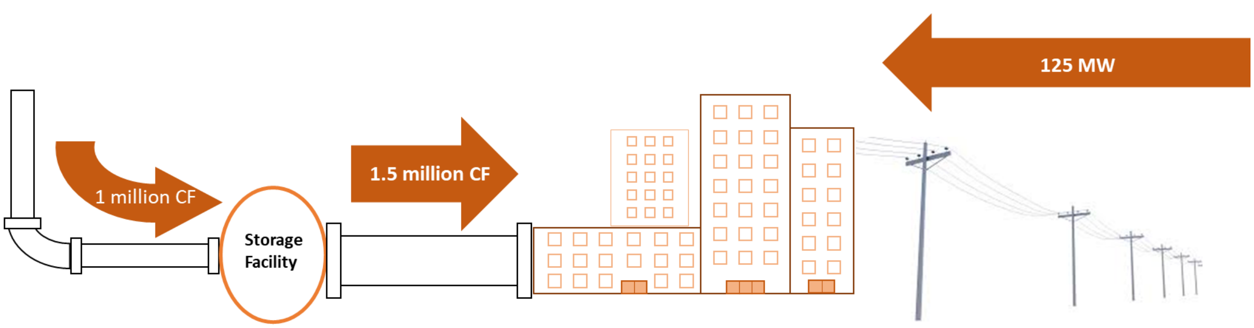
Second, embedded storage enables natural gas pipeline owners to offer more services and greater flexibility to customers. Instead of static contracts for delivery of natural gas from point A to point B at a specific time, pipeline operators can offer products tailored to various customer use profiles, including those that may need gas on short notice (such as a power plant), those that may have varying daily needs (such as a manufacturing facility) and those that need flexibility in both delivery point and quantity (such as a local distribution company) (Aspen Environmental Group 2012).

Third, and perhaps of greatest consequence, embedded storage facilitates optimal design and operation of the natural gas system. Consumption of natural gas, like electricity, is peaky in nature. That is, there are cycles between high-demand periods and low-demand periods on a daily basis. On an annual basis, there are periods of very high demand, which tend to be relatively few in number and short in duration. Because utilities have an obligation to serve the demand of their customers, they must design their system to meet those annual peak periods of maximum demand, even if they only represent a few hours of the year. The result is a system that, for most of the year, is significantly larger (and more expensive) than what is needed.

For example, the Western Electric Coordinating Council (WECC), which oversees electric system reliability for the Western U.S. and Canada, prepares an annual report of transmission system utilization in the region. In 2018, WECC found that on average across the region, transmission lines exceeded 75 percent of their rated capacity just 6.2 percent of the time (about 543 hours) and exceeded 90 percent of their rated capacity just 1.3 percent of the time (about 114 hours) (WECC 2019). Conversely, those numbers mean that after meeting peak demand during a few hours each year, the system had significant levels of unused capacity for the rest of the year.

Having to design the electric system in this way also results in different – and relatively higher – cost structures for customers. Abundant buffering in the natural gas system means that it can store enough gas to meet daily peaks and keep the variable cost of serving customers steady, even as demand fluctuates throughout the day. On the electric side, the only way to meet daily peaks in customer demand is to bring on peaking units that can quickly start up when the peak period begins and shut down when it ends – at higher cost than the resources used to meet normal demand. Since the system cannot be “pre-filled” to meet those peaks, the cost of serving customers necessarily increases during high-demand periods. In recent years, many electric utilities have implemented time-of-use rates, which pass on to customers the higher costs of operating the system during high-demand periods. These rates have two purposes: to align the recovery of those operating costs with the usage of the customers who cause them, and to send a price signal to encourage customers to shift their usage to lower-demand periods. Approximately half of the investor-owned utilities in the U.S. have adopted time-of-use rates (Trabish 2019).

Figure 3 below illustrates the impacts of embedded storage on system design for natural gas and electric systems serving the same city. For simplicity, the figure assumes that average gas demand in the city is 1 million cubic feet, growing to 1.5 million cubic feet at peak. Average electricity consumption is assumed to be 100 MW, with a peak of 125 MW.



Adapted from Aspen Environmental Group 2012

Figure 3. Impact of Embedded Storage on Utility System Design

As Figure 3 shows, embedded storage in the natural gas system allows pipelines located upstream of the storage facility to be sized according to average demand, with excess flows during low-demand periods filling the storage facility. With this buffer in place, only the pipelines downstream of the storage facility must then be sized based on peak demand needs. On the electric side, however, the absence of a buffer requires the entire delivery system serving the city to be sized according to peak needs, meaning that a significant portion of its capacity goes unused during normal operations. It also means that an additional 25 MW of higher-cost peaking generation must be added to the system to meet that demand.

It should be acknowledged that storing natural gas and storing electricity are two very different activities. Natural gas storage is primarily a question of physical space; it can be stored in underground caverns or in manufactured facilities, and can even be stored on a short-term basis in distribution lines themselves. As a result, incorporating storage into the natural gas system has been a relatively straightforward undertaking. Storing electricity, however, has historically only been done in large pumped storage hydro (PSH) facilities, which were originally developed in tandem with large thermal generating stations to shape the facility's fixed amount of generation to changing load patterns throughout the day. Used in this fashion, PSH acted as a buffer for inflexible generators, rather than as a buffer for the broader electric system. Over time, however, these facilities have come to be integrated with transmission functions and used to resolve drastic shifts in load and supply, such as a large generator tripping; or being paid for black start capabilities. But PSH facilities are constrained by geography and physical size, as opposed to gas storage, which can be placed throughout the system.

Recent advances in scalable battery storage technologies, however, have created the potential for energy storage to be sited throughout the grid, as FERC recognized when it added subaccounts for energy storage to the Production Plant, Transmission Plant, and Distribution Plant categories within the Uniform System of Accounts for electric utilities (FERC 2013). The advent of scalable grid storage technologies such as batteries offers significant potential for embedded storage to begin transforming electric grid operations by providing the long-absent buffer. And since batteries can be scaled and sited close to customers, they can maximize the upstream portion of the transmission and distribution systems that can be sized based on average – rather than peak – customer demand. Finally, because they can change from charging to discharging or vice versa and adjust their input or output on a moment's notice, they are naturally suited to provide the flexibility necessary to buffer an electric grid in which supply and demand are both in constant flux.

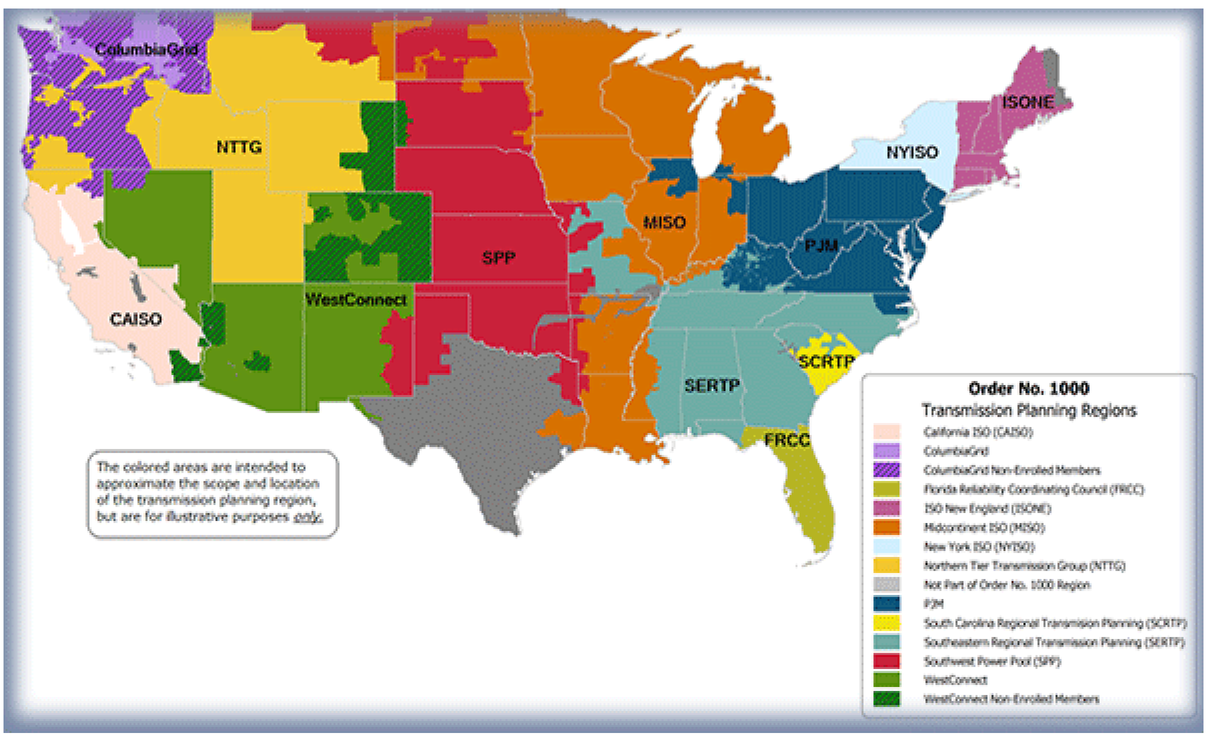
2.0 Survey of Regulatory Questions

While technology has enabled the possibility of embedded storage on the electric grid, the concept raises several regulatory questions that must be answered before it can be realized. This section will provide a brief overview of the U.S. regulatory landscape and then discuss the implications and questions that those structures create for embedded electric storage.

2.1 Overview of U.S. Electric Regulatory Structures

Electric regulation in the U.S. is functionally divided between the federal and state governments. At the federal level, FERC is responsible for regulating interstate transmission, which is also referred to as the bulk power system. FERC's jurisdiction is primarily economic in nature – providing review and approval of transmission system investments and setting the rates that transmission owners can charge customers and other parties for use of those facilities. Where competitive interstate energy markets have been established, FERC also has jurisdiction over market design and rates.

Through a series of orders, FERC has required transmission owners to provide competitive access to their lines and set forth principles for transmission system ratemaking in orders 888 (1996) and 890 (2007). In 2011, FERC issued Order 1000, which requires transmission owners to engage in coordinated, regional transmission system planning and consider non-wires alternatives such as energy storage and demand response in the planning process. Figure 4 illustrates the regional transmission planning groups established pursuant to Order 1000:[1]



FERC

Figure 4. FERC Order 1000 Transmission Planning Regions

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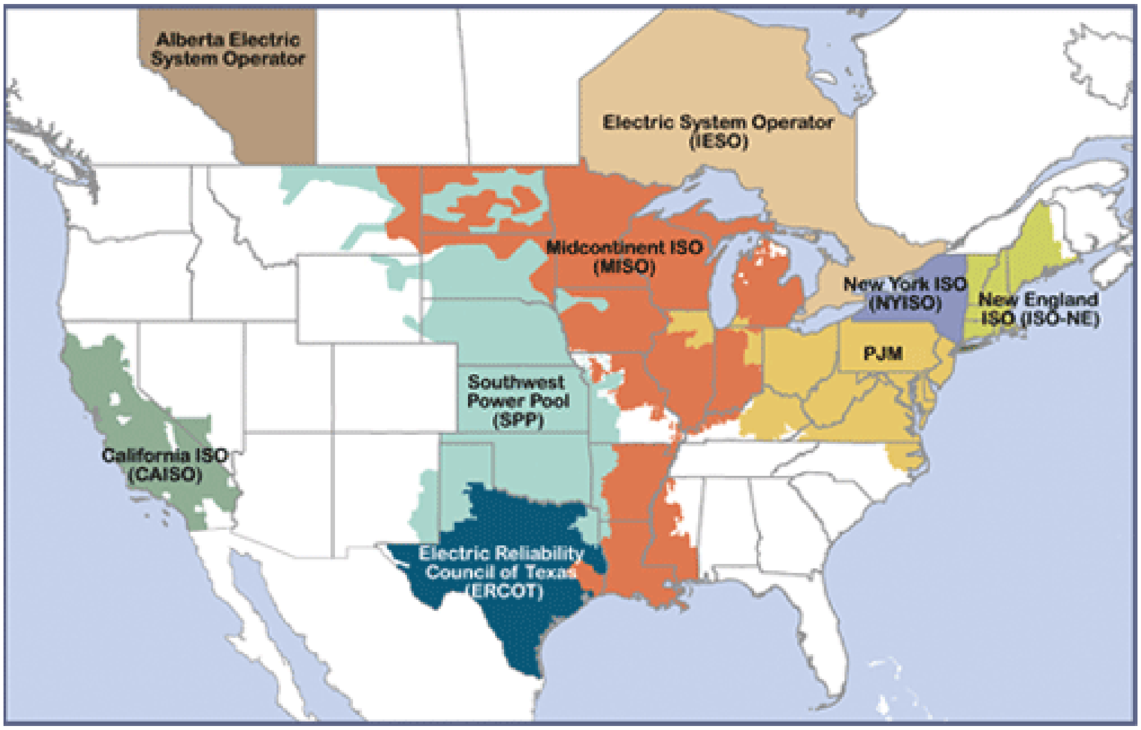
[1] ColumbiaGrid and Northern Tier Transmission Group (NTTG) merged at the beginning of 2020 into an entity known as NorthernGrid.

Using its jurisdiction over interstate wholesale markets, FERC issued Order 841 in 2018, which requires regional market operators to provide fair and competitive access for energy storage by designing market products that recognize and compensate the unique capabilities of storage technologies. Figure 5 below illustrates the competitive market regions in the U.S. and Canada; all U.S. regions are subject to FERC regulation except the Electric Reliability Council of Texas (ERCOT), which is not electrically interconnected with any other state.



FERC

Figure 5. Competitive Regional Energy Markets in the U.S.

In 2005, Congress expanded FERC's authority to include oversight of grid reliability and tasked FERC with creating an Electric Reliability Organization, which would be responsible for developing and enforcing reliability standards, subject to FERC approval. FERC has designated the North American Electric Reliability Corporation (NERC) as that organization, and NERC currently has 98 mandatory reliability standards in place for grid operators (NERC 2020b). Standards cover everything from transmission system planning to infrastructure protection, and also require grid operators to carry reserve generation – both the operational reserves necessary to maintain system balance under normal operating conditions and the contingency reserves necessary to restore system balance in the event of major disruptions.

Where federal authority has historically been based on interstate transmission and sale of electricity, states have historically held jurisdiction over generation and distribution systems. Since the 1990s, states have taken two approaches to energy regulation: the vertically integrated model and the deregulated model.

Under the vertically integrated model, a single utility retains control over all three electric functions: generation, transmission, and distribution. State regulators review utility investments and set rates for all three functions, with any transmission revenues earned through FERC-established rates used to offset transmission costs to the utility's customers.

Details of the deregulated model vary by region, but in general, dispatch of generation resources is done through competitive markets administered by an independent system operator (ISO) or regional transmission organization (RTO) according to FERC-approved procedures and rate structures. Utility ownership of generation assets varies by region; some regions allow it and some prohibit it. Utilities retain ownership of their transmission assets, but place them under the operational control of the ISO or RTO, which also coordinates transmission planning for the region and collects transmission revenues on behalf of participating utilities.

Utilities that own interstate transmission lines – either in a vertically integrated or deregulated construct – file FERC rate cases on an individual company basis, and FERC sets the rates that utilities are authorized to charge for use of their transmission facilities by other parties. Under most deregulated models, the only function that remains directly under utility control and state regulatory authority is distribution.

2.2 Regulatory Implications for Embedded Storage

The regulatory structures identified in the previous section establish the paradigm within which embedded storage assets would operate. Specifically, these structures have implications on how such assets would be identified in grid planning processes and, once constructed, how they would be compensated.

At a fundamental level, almost every component of the U.S. electric grid is compensated in one of two ways: through a fixed rate set by regulators, or through a competitive rate set by a market. Where regulators set the rate, it is done through a general rate case process, which has two parts: cost allocation and rate design. During the cost allocation phase, regulators:

1. Review the utility's investments for reasonableness;

2. Determine the share of investment costs that can be passed on to customers;

3. Authorize a rate of return (profit margin) for the utility to earn on its investments; and

4. Allocate the utility's total authorized revenue (which includes both recovery of its investments and the authorized rate of return) across different customer groups (industrial, commercial, residential) based on each group's usage of the grid.

During the rate design phase, the duty of regulators is to set rates that will provide the utility with a reasonable opportunity to recover its authorized revenue based on average annual customer usage.

Where costs are recovered through competitive market rates, the asset owner is responsible for bidding the resource into various market products, such as providing capacity, energy, reserves, or other ancillary services needed to keep the grid in balance. How much revenue the asset can earn is determined by the owner and market forces; the primary role of regulators in this model is to assure that market products and mechanisms will procure the necessary portfolio of resources to maintain reliable service at a reasonable cost. Certain assets may face risks in this model if market design does not recognize their capabilities and fairly compensate them for the services they provide; FERC identified and sought to correct such market failures related to energy storage in Order 841.

Delivery infrastructure – transmission and distribution system equipment including lines, substations, and transformers – are almost universally compensated through fixed rates set by regulators.[1] Generation assets are compensated through fixed rates in vertically integrated territories and competitive rates in deregulated territories.

Based on its proposed function – as an integrated grid component that helps manage and optimize power flows – embedded storage on the electric grid would be part of the delivery system, and therefore a regulated asset subject to fixed-cost recovery. Conceptually, it would act as a natural buffer within the system between constantly fluctuating generation and loads. This type of use would require the device to operate independent of market signals as necessitated by grid conditions.

Current market structures measure energy imbalance – the difference between expected generation and load and actual generation and load – and compensate flexible resources that can adjust their output to remedy the imbalance. In wholesale markets, competitive ancillary service products such as frequency regulation, spinning reserve, and non-spinning reserve secure these services on a regional basis. In vertically integrated territories, the utility is responsible for setting aside reserve generation to provide those services. The Energy Imbalance Market, which includes the California ISO and several vertically integrated utilities in the Western U.S., provides an interface for market participants and non-market participants to trade balancing resources. In each case, the transaction is based on correcting an observed imbalance. But one of the primary functions of an embedded storage asset would be to act as a buffer between load and generation, absorbing volatility from both and reducing or preventing imbalances. This proactive approach to grid power flow volatility management is not something which reactive market structures are designed to measure or compensate. Under current market structures, therefore, there is no pathway for development of embedded storage as a competitive asset.

From a planning perspective, U.S. energy regulatory structures create multiple grid planning processes. Transmission plans are subject to FERC oversight and are prepared by individual, transmission-owning utilities, who then submit those plans for consideration and analysis in a regional planning process as required by Order 1000. Distribution system planning is done by individual utilities under state oversight, though the degree of oversight that states exercise in this space varies and is an area of active development around the country (Homer et al 2017). Generation planning for vertically integrated utilities is an internal process subject to oversight by state regulators, while most ISOs employ some form of centralized energy planning and procurement process.[2]

Given those processes, the most conducive venue for initially studying embedded storage would likely be a regional transmission plan. In that process, planners employ sophisticated power flow models to understand how electricity moves through the region and how the grid behaves under multiple scenarios. NERC's transmission planning standard identifies multiple contingency analyses that each regional process must perform to identify under what circumstances – and where –additional flexibility is needed. Accurately incorporating embedded storage into these models would provide the clearest picture of how adding buffers to the bulk

[1] Under certain circumstances, FERC has authorized non-utility transmission line owners to negotiate rates for usage of their facilities. See https://www.ferc.gov/sites/default/files/2020-04/E-2_36.pdf.
[2] In some ISOs, notably CAISO and SPP, utility resource plans subject to state regulatory approval remain a factor in the planning process.

power system would increase internal flexibility and reduce the need for the grid to seek external flexibility from generation resources.

Distribution system planning is another conducive process for studying embedded storage. As customer adoption of DG and EVs continues to rise, so will the need for buffers in the distribution system, to absorb excess generation and prevent backflows on circuits with high penetration of DG, and to inject additional power to support EV charging demand. At lower levels of adoption, it is likely that regulatory mechanisms such as time-of-use rates or tariff requirements can cost-effectively manage those challenges and ensure that the costs created by such resources are borne by their owners. To address the grid impacts of high DG penetration, for example, Hawaiian regulators have amended the state's net metering policies to require new customers installing rooftop solar to either allow the utility to curtail their generation when necessary for grid reliability, or to install energy storage to either keep all generation onsite or to shape it and only export it to the grid at certain times.

However, as customer adoption of distributed energy resources like DG, EVs, storage and grid-interactive appliances continues to grow, and as new technologies enable more visibility into and control over distribution system operations, some have suggested a Distribution System Operator (DSO) role, which would be responsible for balancing supply and demand at the distribution system level, similar to the way that an ISO operates the bulk power system (De Martini and Kristov, 2015). In that potential structure, embedded storage acting as a buffer between the DSO and the ISO could create value by capturing errant flows between the two entities, thereby reducing the need for reserve resources and infrastructure investments at both levels. Section 4 will discuss this concept in additional detail.

2.3 Key Regulatory Issues Raised by Embedded Energy Storage

While the energy regulatory structure in the U.S. creates a framework that could potentially accommodate embedded storage, there is no clear mechanism by which it could make its way onto the grid. Any effort to create a regulatory pathway for embedded storage would have to address, at a minimum, five key regulatory issues:

1. Lack of underlying standards
2. Barriers in planning processes
3. Ownership model
4. Compensation structure
5. Metrics

Lack of underlying standards. Reliability standards are the backbone of the electric industry, governing every aspect of its design and operation. They form the objectives that transmission planning models must meet, establish the reserve resources that grid operators must procure, and dictate the operational requirements for the grid. The primary function of all grid planning activities – whether for generation, transmission, or distribution – is to identify the investments necessary to satisfy those reliability requirements at the lowest reasonable cost.

That planning framework is a key product of reliability standards. In a reliability planning paradigm, the need for a resource – be it a generator, a transmission line, a substation, etc. – is established, and the planning objective is to identify the most reasonable-cost, best-fit solution. Where a resource doesn't explicitly meet a reliability need, it is considered in an economic paradigm, in which it is evaluated on its ability to improve system efficiency. Embedded storage doesn't fit within either paradigm. There is no reliability standard to expressly support it, and while it may make the grid more resilient against significant disruptions, there are no resilience standards by which that contribution could be measured – and therefore justified. Economically, the likely impacts of embedded storage do not readily lend themselves to quantification and compensation through a market construct, and as will be discussed below, those benefits are diffuse and would require a much more integrated approach to grid planning that what is currently practiced.

The result is that embedded storage has no clear implementation pathway. Absent underlying standards associated with embedded storage, either explicitly or a requirement that embedded storage best resolves, planning models cannot identify it as a solution. And if a model cannot identify a need for it, utilities cannot justify investments to regulators, and markets cannot create a product for it. Even when standards exist and models identify storage as a best-fit solution, the assets are limited to providing the function associated with the need. This narrow application of planning to standards may result in the addition of storage, but only for the express solution identified; the wider benefits of networked and flexible storage are lost.

To illustrate this point, it may be helpful to consider two instances in which regional transmission plans identified a need for storage. In 2018, the California ISO (CAISO) Transmission Planning Process identified an energy storage device as the most cost-effective means of meeting a reliability need near Dinuba, CA. In the planning process, CAISO identified a contingency scenario in which if a nearby transmission line went down, the resulting additional flows would overload the transmission system near Dinuba. By placing an energy storage asset at the local substation, the storage could absorb those excess flows and protect the local system at a lower cost than rewiring it to manage the additional flows (CAISO 2018).

In its 2019 Transmission Expansion Plan, the Midcontinent ISO (MISO) selected an energy storage asset to manage a reliability issue near Waupaca, WI. The issue identified in this instance is essentially the opposite of the one identified by CAISO; in the event of an outage for a nearby transmission line, there would be insufficient power to serve the Waupaca area. By performing some minor reconfigurations of the existing transmission system and placing an energy storage device at a local substation, MISO determined that it could cost-effectively maintain service to the Waupaca area in the event of an outage (MISO 2019).

To date, these are the only two instances in which a regional transmission planning process has identified an energy storage solution, and they are indicative of the limited role that storage can play in current transmission planning processes. In both instances, the storage is only providing a single, narrow service. As reliability assets placed on the grid to respond to a contingency event, the devices are only used in the event of a very specific problem with the grid, and are likely to only be used a handful of times during their useful lives. Current reliability standards are reactive in nature – designed to identify where issues may occur and build additional redundancy into the system to resolve them. Embedded storage could facilitate a more proactive approach to reliability planning by employing buffers to prevent momentary fluctuations in supply and demand from propagating into reliability issues.

Barriers in planning processes. It could be argued that if embedded storage truly creates value for the grid, then existing transmission planning practices should be able to consider and recognize it. Order 1000 directs transmission planners to evaluate system needs from three perspectives: reliability standards, system economics, and public policy requirements. While the first and third categories are driven by external factors, the economic analyses are internally focused – intended to understand how power flows across the bulk power system and identify cost-effective ways of improving those flows. Theoretically, this would create a window for embedded storage to be studied. However, these economic analyses are primarily focused on identifying and alleviating congestion – locations on the grid where transmission constraints increase the cost of delivering power (Eto and Gallo 2017). While reducing congestion is one potential value that embedded storage could provide to the grid, any study that narrowly focuses on that one value would miss the broader impacts that embedded storage would provide, and would be highly unlikely to identify embedded storage as a least-cost, best-fit option.

Furthermore, regional transmission planning practices have historically been slow to consider emerging technologies. For example, Congress indicated in the Energy Policy Act of 2005 that various technologies, including energy storage, should be considered as alternatives to transmission system infrastructure. In Order 1000 issued in 2011, FERC reinforced that directive by encouraging regional transmission planning processes to include energy storage and other non-wires alternatives in their studies. However, as previously discussed, it wasn't until 2018 that CAISO developed the first regional transmission plan that thoroughly analyzed – and selected – a storage alternative. MISO's 2019 plan is the only other plan to have followed. CAISO and MISO have both developed procedures for how storage can participate in the transmission planning process, something other regions have not yet done, and those regions have yet to transparently evaluate energy storage as a transmission asset. This discrepancy indicates that absent specific regulatory guidance or requirements for how new technologies are to be included in planning practices, they are unlikely to be considered.

A possible factor in the slow uptake of new technologies in regional transmission planning is that regional transmission plans are not subject to formal regulatory review. The primary regulatory function of regional transmission plans is to serve as evidence when the assets that the plans selected are ultimately built and brought before FERC and state regulators for approval and rate recovery. While FERC and NERC establish rigorous criteria for what transmission plans should cover, the final plans themselves are not formally reviewed or approved by either entity. The result is that even where FERC has established expectations for plans to consider new technology solutions, there is no direct enforcement mechanism to ensure that they did so.

Ownership model. Even if embedded storage made its way into a plan and were selected for investment, there would remain a question of who would build and own the asset. Historically, existing transmission asset owners had a right of first refusal to submit alternatives for consideration in a regional planning process. FERC placed limits on that right in Order 1000, requiring planning processes to grant fair and equal consideration to projects proposed by nonincumbent transmission developers. While FERC acknowledged that competitive bidding for transmission projects could reduce their costs, Order 1000 did not require competitive bidding. Nevertheless, some regional planning organizations conduct competitive bidding for certain projects; CAISO conducts competitive bidding for all projects selected for regional cost allocation, while ISO New England (ISO-NE) conducts competitive bidding for any need that is more than three years in the future.

Because of its potential role in the bulk power system, embedded storage raises complicated questions of operational control and cybersecurity. Balancing those security concerns with policy interests in competitive solicitation and ownership of transmission assets, and ensuring that any third-party owned assets comply with safety, reliability, and security standards are matters that would have to be addressed.

Compensation. The lack of underlying standards and the obstacles in current transmission planning practices collectively mean that embedded storage, even if constructed, would have no obvious mechanism for compensation – either as a market or a regulated asset. Market products are designed to compensate resources for the measurable contributions that they make toward meeting reliability standards – products like energy, capacity, and various ancillary services. If there is no objective standard to be met, there is no way to quantify how much of the service is needed or what it's worth. By limiting or preventing imbalances, embedded storage's reliability contributions would be counterfactual in nature, and markets are not designed to compensate what they can't measure.

Regulated assets, meanwhile, require documented justification to earn regulatory approval and rate recovery. That documentation generally comes in the form of a resource or transmission plan that describes the system need, conducts a comparative analysis of different options, and identifies the best solution. If there is no standard, a plan cannot identify a need, and if the need cannot be identified in a plan, investments cannot be justified to regulators.

Metrics. Every asset's contributions to the grid are measured in some way. Generation assets are measured by their energy production and/or their contributions to reliability standards, while transmission and distribution infrastructure are measured by their contributions to power flows and power quality. How would the contributions of embedded storage be measured? How can the impacts of a buffer be quantified? It would likely entail a blending of traditional metrics – capturing not only its impact on bulk power system flows, but its impact on generation and ancillary service needs. Additional metrics, such as its impacts on daily price swings and locational marginal prices, may also be appropriate. This type of multi-faceted analysis would be difficult to conduct in existing functional and planning siloes, particularly where different functions are under the operational control of different entities. Embedded storage's ability to absorb energy would also add a challenge not readily addressed in existing planning models. Section 3 will discuss how these different planning processes and models might be coordinated to conduct a thorough economic analysis of embedded storage.

3.0 Potential Pathways Forward

Now that the potential benefits of embedded storage on the electric grid and the regulatory barriers that would impede its development have been identified, this section will explore potential pathways forward. This section proposes two conceptual approaches – an incremental approach consisting of minor reforms to grid planning processes, and a complex approach consisting of new reliability standard development. These pathways are intended for discussion purposes, and should not be interpreted as formal recommendations. The section concludes by discussing the implications of embedded storage on existing planning frameworks and identifying how various modeling processes would need to be coordinated to capture the full value of embedded storage.

As suggested in Section 2, regional transmission plans are a logical venue for studying the benefits of embedded electric storage. Order 1000's planning requirements establish transparent processes by which regional power flows must be analyzed and, where necessary, improved. As such, this process is uniquely suited to identifying the broadest range of embedded storage benefits at regional scale.

This is not to diminish the role that embedded storage would play on the distribution system. Because transmission and distribution are in fact electrically one whole system, embedded storage would simultaneously impact distribution systems positively through the same volatility management mechanism as with transmission. But given the structure created by Order 1000 and NERC transmission planning standards, regional transmission plans present a more readily adaptable entry point for embedded storage to be analyzed. This is not to meant to preclude the possibility of expanded coordination in regional transmission plans to work with local distribution companies to identify mutual benefits created by embedded storage. Indeed, with FERC's recent direction in Order 2222 for ISOs to increase their coordination with distribution system operators to facilitate the orderly usage of distributed energy resources, there may be increased coordination in transmission and distribution system planning processes in coming years.

Both pathways forward presented in this section are expressed in terms of the reliability standard that governs transmission system planning, NERC standard TPL-001-4, which establishes seven types of contingency analysis that all transmission plans must address. These contingencies are often referred to as "n-1" or "n-1-1" analyses, in which "n" represents the system in its normal state, and analyses assume that a major component of the grid fails, such as a generator or a transmission line (n-1), or that one major component's failure is compounded by the failure of a second major component (n-1-1). The objective of these contingency analyses is to identify the conditions under which the grid would lose stability and formulate a corrective action plan to add additional redundancy or flexibility to ensure stability.

3.1 Incremental Pathway

An incremental pathway forward for embedded storage is one that does not include the development of new reliability standards, but rather works within the framework created by existing standards. Under this approach, regulators could drive minor reforms to transmission system planning by encouraging or requiring analysis of embedded grid energy storage within the system and contingency analyses required by NERC TPL-001-4.

The advantage of this approach is that it can be done relatively quickly through more nimble mechanisms. FERC, as the ultimate arbiter of grid reliability standards, would be the logical venue for such an action. FERC could drive changes either through an order, which establishes legally binding requirements for the entities that it regulates, or through a policy statement, which provides non-binding guidance for regulated entities to consider in their operations. FERC has addressed regulatory issues related to energy storage through both mechanisms in recent years, issuing a policy statement to establish guiding principles for the development of dual-use (generation and transmission) energy storage assets in competitive markets in 2017, and issuing Order 841 in 2018, which required market operators to create participation models for energy storage in competitive markets. FERC can conduct a proceeding that results in an order or policy statement within a matter of months.

The disadvantages of this approach are that it would be difficult to enforce and that transmission system analyses may not be able to identify best-fit applications for embedded storage because of their focus on the transmission system. FERC could potentially address the second issue by establishing clear guidelines for what benefits an embedded storage analysis should consider, including those that are traditionally beyond the scope of transmission planning (such as impacts to wholesale markets or distribution systems). But the enforcement challenge is more difficult. As discussed in Section 2, the lack of direct oversight of regional transmission plans appears to have been a factor in the slow and uneven incorporation of new technologies into those plans, even where FERC has provided guidance.

3.2 Reliability Standard Pathway

As its name implies, this pathway would include the revision of existing reliability standards or the development of a new standard specific to embedded storage.

The advantage of this approach is that it is the most direct means of changing the way the electric system is planned, constructed, and operated. As has been argued throughout this paper, standards provide the basis for planning, operating, and paying for the electric grid. The only certain way to create a process capable of analyzing and identifying best-fit opportunities for embedded storage is to create a reliability standard that would justify the analysis and any ensuing investments.

The disadvantage of this approach is that reliability standard development is a lengthy process that can last for years. Proposed reliability standards are subject to extensive analysis and review by grid operators and other NERC members, who must ultimately approve any standard by a vote. Along the way, proposed standards may be revised, split into different standards, or rejected and amended. While relatively simple standards may be approved in under two years, more complicated standards (as a new standard for embedded storage would likely prove to be) may spend several years in development.

3.3 Model Coordination

As discussed in Section 2, a full economic analysis of embedded storage within current planning structures would be challenging, since its benefits fall under different planning processes, each of which considers different facets of the electric grid under varying time horizons. Power flow benefits, for example, would be captured by a transmission system model, while impacts on generation and ancillary service needs would be captured by a system expansion model, and impacts on daily price swings and system power costs would be captured by a market or power cost model. Finally, distribution system models would be needed to quantify any benefits or impacts on the distribution system. Figure 6 illustrates the scope and planning horizon for these various planning processes:

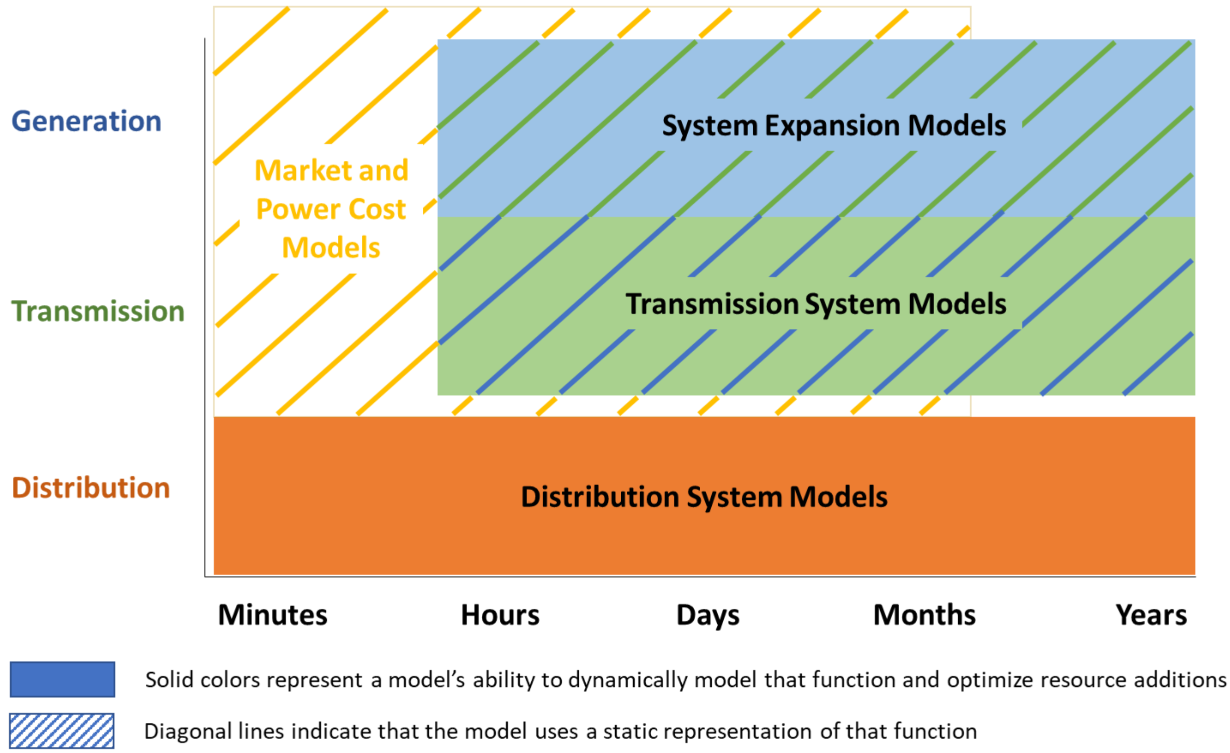


Figure 6. Comparison of the functional scope and time horizon of grid planning processes

While the exact mix of models and how they are used may vary from one region to another, Figure 6 illustrates how the models generally fit together. A system expansion model, for example, can be used to dynamically optimize the generation fleet and identify the most cost-effective additions over a period of many years, but will do so using a static representation of the transmission system. It can consider alternate scenarios in which a transmission asset is assumed to be built, but it cannot optimize the transmission system or identify whether the assumed addition is the most cost effective. The inverse is true for a transmission system model – it can dynamically model the transmission system and identify optimal additions, but will do so based on a static representation (actual or assumed) of the generation fleet. Market and power cost models are used by regional market operators or individual utilities to optimize generator dispatch and ancillary services over a short to medium term (up to one year) based on expected loads, but cannot identify optimal additions to either the generation fleet or the transmission system. Finally, distribution system models can optimize and expand the distribution system over extended time periods, but do not consider other functions.

Therefore, it would take a coordinated effort across multiple planning processes to fully quantify the benefits of embedded storage. While an embedded device would not "value stack" in the same way that storage assets have traditionally done by dispatching to various market signals, its use to manage power flows would create value across the functions of generation, transmission, and distribution. Capturing and accounting for those values during the planning process would require a more integrated approach to planning that what is currently employed.

4.0 Summary and Next Steps

In virtually every commodity, storage is ubiquitously embedded in a manner that can easily be taken for granted. Whether it is wheat, water, gasoline, or consumer electronics, the existence of storage-rich supply chains creates a buffer against mismatches in supply and demand, which reduces costs and protects customers. Due to the technological challenges of storing it, electricity is the only major commodity whose delivery structure had to be constructed without storage.

Recent technological advances in cost-effective and scalable electric energy storage technologies have created the possibility for electricity to “catch up” with other commodities. Embedded electric storage holds fascinating potential to improve grid efficiency and reduce costs for customers. But the complexity of how the electric grid is planned, operated, and regulated means that figuring out how, where, and how much storage could be reasonably embedded will not be an easy process.

This paper has viewed the challenges of embedded storage through a regulatory lens. By exploring the energy regulatory landscape of the U.S. and its ramifications for the concept of embedded storage, it has identified some of the regulatory issues raised by this idea and suggested pathways forward for addressing them.

But many questions related to embedded electric storage still remain, such as:

1. **Metrics.** How will embedded storage’s contributions to the grid be measured? By what standards will assets be sized and placed?

2. **Performance characteristics.** What are the specific functions that embedded storage will be asked to do? What would be the power and energy requirements? Are existing commercial technologies capable of meeting those needs, or are additional research and development necessary?

3. **Impact on operational reserves.** The lack of buffering in the current electric grid requires operators to carry costly operational reserves to balance the grid. Theoretically, embedded storage would act as a buffer between supply and demand, reducing the need for generation assets to provide that function. But how can the impact of embedded storage on those reserve levels be quantified? If sufficient benefit is identified, how can deployment be phased to guard against stranded investments?

Economic questions such as these will be the focus of a subsequent paper in this series, which will generally investigate the question of how embedded storage assets should be valued.

It may also be of value to think about designing a pilot project to test the feasibility and value of embedded storage on the electric grid. One approach that may provide significant insight into the effects of embedded storage on all grid functions would be to deploy embedded storage at a substation, to act as a buffer between the transmission and distribution systems. Ideally, this project would be sited at a point where the transmission and distribution system are under different operational control, such as a DSO as described in Section 2 or a local distribution utility that purchases wholesale power from an entity responsible for managing the bulk power system. Such an approach would ensure a clear understanding of how embedded storage affects operations on either side of the seam between the distribution and transmission systems.

As discussed in this paper, the uncertainty inherent in balancing variable generation and variable loads requires grid operators to carry reserve resources to ensure reliability. System frequency and energy imbalance – the difference between expected generation and loads – are the primary metrics for measuring this variability.

But what if there were no imbalance? What if a distribution system with a portfolio of distributed energy resources used those resources to internally balance its system and adhere to its scheduled energy deliveries from the bulk power system? What if embedded storage were placed at the seam with the transmission system to absorb errant flows from either side and re-inject them as needed?

From the bulk power system perspective, the point of delivery at that substation would be steady, meaning that there would be a reduced need to carry reserves to account for load uncertainty at that node. And if that embedded storage could also absorb excess generation during one period and then re-inject it during a period of insufficient generation, then there would be a reduced need to carry reserves to account for generation uncertainty on the bulk power side. And if there were enough of those buffers strategically placed on the grid, those impacts may begin to efficiently reshape the way we operate the electric grid. An initial project to test and quantify those impacts would be a logical place to start.

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