Market and Policy Barriers to Deployment of Energy Storage☆

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Abstract

There has recently been resurgent interest in energy storage, due to a number of developments in the electricity industry. Despite this interest, very little storage, beyond some small demonstration projects, has been deployed recently. While technical issues, such as cost, device efficiency, and other technical characteristics are often listed as barriers to storage, there are a number of non-technical and policy-related issues. This paper surveys some of these main barriers and proposes some potential research and policy steps that can help address them. While the discussion is focused on the United States, a number of the findings and observations may be more broadly applicable.

Keywords: Energy storage, electricity markets, externalities, incomplete markets, energy policy

1. Introduction

Recent developments in the electricity industry have increased interest in the use of energy storage as part of the operation of the electricity grid. These developments include the introduction of restructured electricity markets that signal the value of electricity services and the increasing use of variable renewable energy sources, such as wind and solar. This interest has spurred new storage demonstration projects, proposals for significant expansion of storage deployment, and increased research into novel storage technologies.

The deployment of grid-scale energy storage is dependent on the economic benefits to a developer in either a traditional regulated or restructured market. EPRI (1976) provides an early discussion of storage technologies and their relative economic performance. Because it is framed by the 1970s, before the advent of restructured electricity markets, the focus is on storage use by a vertically-integrated utility to replace peaking generation capacity. More recent analyses, including the works of EPRI-DOE (2003); Eyer et al. (2004); Eyer and Corey (2010); Denholm et al. (2010), recognize that storage can provide a much broader array of services—ranging from wholesale energy and capacity for the bulk power system to backup energy for an individual building or home. Table 1 categorizes these services into seven broad categories, giving a brief explanation of each service. Some of the applications are not be amenable to all storage technologies, depending on the specific circumstances, site under consideration, and necessary technical characteristics, and such restrictions are also noted in the table. Storage technologies are characterized by energy and power capacities, which can be important deployment considerations. For example the limited energy capacity of flywheels and some batteries restricts them to short-duration services such as regulation. Other technologies, such as pumped hydroelectric storage (PHS), typically have storage capacities of multiple hours and can provide a larger range of services. These different characteristics also makes uniform comparison of storage technologies (for example on a \$/kW or \$/kWh basis) difficult and often of limited use. Detailed technology characterizations and cost estimates of existing and emerging technologies are provided by EPRI (2010).

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Table 1: Major energy storage applications

Application	Description	Necessary Characteristics
Energy Arbitrage	Storing low-cost energy which is discharged and sold when prices are higher.	Discharge time of hours.
Generation Capacity Deferral	Discharge energy during peak-load hours, reducing the need for peaking generators.	Discharge times of up to a few hours.
Ancillary Services		
Regulation	Increase or decrease in net output of storage to ensure real-time balance between system energy supply and demand.	Response time of seconds to minutes. Charge and discharge times are typically minutes. Service is theoretically zero net energy over extended periods of time.
Contingency Reserves	Increase in net output of storage to response to a contingency, such as a generator or transmission outage.	Response time of minutes. Discharge time of up to a few hours.
Ramping	Follow hourly changes in electricity demand.	Response time of minutes to hours. Discharge time of hours.
T&D Capacity Deferral	Storing energy when T&D are lightly loaded and discharging when T&D are constrained.	Response time of minutes to hours. Discharge time of hours. Small-scale deployments may be necessary, depending on each specific site.
End-User Applications		
Managing Energy Costs	Storing energy when retail price is low and discharging when price is higher. Functionally equivalent to Energy Arbitrage.	Response time of minutes to hours.
Power Quality and Service Reliability	Using storage to improve power quality (*e.g.* voltage, frequency, harmonics). Discharging storage during a service outage.	Response time of seconds to minutes. Discharge time of hours.
Renewable Curtailment	Reduce curtailment of renewable generation due to generator (*e.g.* ramping, minimum load) or transmission constraints.	Response time of minutes to hours. Discharge time of hours.

Despite these benefits, there has been little actual storage deployment in the United States in the last two decades. ASCE (1993); Denholm et al. (2010) note that much of the construction of about 20 GW of PHS was initiated in the United States in the 1970s. Interest in storage then diminished in the 1980s, with little new capacity installed. More recently, storage deployment in the United States has been limited to a single 110 MW compressed air energy storage (CAES) plant that started operation in 1992 and other smaller demonstration and pilot projects. Although manufacturing costs, roundtrip efficiency, and other technical characteristics are often cited as major barriers to storage adoption, there are numerous non-technical issues plaguing the technology as well. These include storage valuation and market design issues, regulatory treatment of storage, significant risk and uncertainty associated with storage deployment, and limited support of the technology. In this paper we outline some of the main non-technical barriers to storage adoption and suggest regulatory, policy, and research steps that could help overcome these issues.

In this paper we have intentionally framed this discussion around markets and the regulatory landscape in the United States. Although the particulars of each country differ, many of the issues that we raise should be applicable more generally to storage adoption outside of the United States. Nevertheless, differences in market structure, regulation and natural resources between countries are likely to significantly impact the relative economics and barriers to deployment. While the focus of this paper is the use of stationary energy storage, it is important to recognize that these issues could also apply to the use of electric vehicles for grid services and other competing technologies, such as demand response (DR).

We divide these barriers into four broad categories, which are discussed in the following sections. Section 2 discusses issues surrounding the valuation of storage services. Section 3 discusses regulatory treatment of storage. Section 4 discusses risk and uncertainty surrounding storage development, including limited support from government and the electricity industry. Section 5 then concludes. While we have separated these issues for ease of exposition, many are interrelated and these linkages are discussed as appropriate.

2. Incomplete Valuation of Benefits

2.1. Incomplete Markets

One of the more commonly cited barriers to the deployment of storage is the inability to quantify and capture the multiple value streams provided to the grid. Before the advent of restructured markets, valuation of storage usually only considered the ability of storage to provide two basic classes of services—firm capacity and 'load-leveling' (charging storage with low-cost off-peak generation and displacing high-cost on-peak energy). Other benefits, such as ancillary services (AS), were rarely valued. This lack of valuation in regulated markets is in large part due to the limitations of capacity-expansion and simulation software used by utilities. The emergence of restructured markets and the introduction of AS markets with appropriate price signals has led to recognition and valuation of fast-response services that are well suited to certain storage technologies. Indeed, the most active deployment of batteries and flywheels in the United States is in locations with restructured markets to provide frequency regulation reserves. Examples include a 3 MW flywheel project and a 20 MW plant in the New York ISO market and a 1 MW battery in PJM. These investments were made possible, in large part, by Order 890, which was issued by the Federal Energy Regulatory Commission (FERC) in 2007 and requires wholesale markets to consider non-generation resources (including storage and DR) for grid services. As a result, a number of market operators have created new tariffs allowing storage to participate in AS markets.[1] More recently, FERC approved Order 755, which provides higher compensation for fast response regulation services, citing storage as an example of a technology that is not currently valued appropriately.[2]

Despite these developments, significant limitations remain in the market valuation of energy storage. This is due to the inefficiency of price signals for some services, and the lack of transparent prices to end users in other instances. For example, of the applications listed in table 1, those serving the distribution network or the end user have limited or zero market exposure. The value of customer-sited 'behind the meter' storage is dependent on utility rate structures, which currently often poorly capture the time-varying cost of electricity. Those rate structures that do vary as a function of time, for instance critical-peak or time-of-use pricing, typically do so in a predetermined fashion, which cannot be dynamically adjusted in real time. The current lack of 'smart grid' technologies (*i.e.* communication between system operators (SOs) and load-sited resources) precludes the real-time dispatch of storage devices and provision of many services, including valuable AS. This limits the deployment of storage by eliminating a potentially important market participant, but also important is the lack of gaining the technical and economic benefits of distribution- and load-sited storage. Load shifting by end users to manage energy costs is functionally equivalent to energy arbitrage, so in one sense it doesn't matter if the device is sited at load or in the transmission network. From the standpoint

[1] For example, the New York ISO created a limited energy storage resource tariff, details of which can be found in FERC docket number ER09-836-000, and the Midwest ISO created a stored energy resources tariff, which can be found in FERC docket number ER09-1126-000.

[2] Details of the rule can be found in docket number RM11-7-000.

of system complexity it is currently far easier to plan and dispatch fewer large transmission-sited assets than many hundreds or thousands of customer-sited storage devices. However customer-sited storage provides very real and quantifiable benefits of reducing future distribution infrastructure requirements and T&D losses. For example, Nourai et al. (2008) note that since transmission and distribution losses are proportional to the square of line loading, using storage to intertemporally shift transmission- and distribution-level loads can reduce such losses. These avoided losses can also increase the effective peak-capacity benefits of load-sited storage, as well as improve transmission and distribution utilization, which can reduce the need for new infrastructure. Since the distribution network is now, and likely to remain, part of a regulated monopoly, and because locational marginal prices (LMPs) are not computed at the distribution level, it will be difficult to access these benefits absent policy interventions (such as the introduction of markets) or smart grid technologies. As a result, there are currently little to no incentives to place storage at the locations where it could potentially provide the greatest benefit. This challenge is particularly notable for storage technologies, such as thermal energy storage (TES), that can only be load-sited. Given the challenges of customer adoption, it may be easier to develop business models that deploy utility-owned but customer-sited storage. At least one TES manufacturer has taken this approach[3] and in 2010 a consortium of municipal utilities in southern California began installing 53 MW of distributed ice storage systems as a system resource using this business model.[4] This type of approach is not dissimilar to the use of third-party owners acting as a bridge between utilities and customers to ease photovoltaic solar adoption, as noted by Cory et al. (2008).

Conversely, restructured markets can provide incentives for siting storage to relieve transmission constraints. Walawalkar et al. (2007); Sioshansi et al. (2009) demonstrate this by using historical LMP data to show that arbitrage values can vary significantly within a transmission network, due to systematic LMP differences. They speculate that such revenue differences could encourage storage development at the most-congested locations in the network (subject to the site being able to accommodate the physical characteristics of the technology) to capture the higher revenues. This model of storage development is akin to the merchant transmission model advocated by early market restructuring proponents, such as Hogan (1992); Chao and Peck (1996); Bushnell and Stoft (1996, 1997). Joskow and Tirole (2005); Sauma and Oren (2005, 2009) demonstrate, however, that in the presence of market power, lumpy investments, and other realities of electricity systems, this merchant transmission model may result in inefficient investment, which would presumably affect storage investment in a similar manner.

There are other benefits of storage that are either poorly or not at all captured in existing markets. This is often because provision of the services is not efficiently coordinated by markets or due to market design constraints. Many power quality-related services, including voltage support and reactive power, are not priced in markets. This is due to extreme locational market power that arises because of physical realities of power flows—oftentimes only a single generator, which would be a *de facto* monopolist, can provide the service to a particular transmission bus. Thus provision of these services is often coordinated by the SO to meet reliability and quality mandates, with generator costs recovered through uplift-type payments.

Another poorly priced benefit of storage is its ability to reduce generator ramping and cycling. These benefits arise when storage is used for energy arbitrage, and can become increasingly important as variable renewables place added strains on conventional generators, as noted by GE Energy (2010). Sioshansi et al. (2010) demonstrate that because LMPs are typically computed using a static optimal power flow that does not explicitly include generator ramping constraints, they do not capture the cost of ramping. If LMPs are instead computed using a dynamic model, they show that an intertemporal subsidy occurs—prices during hours in which generators are ramp-constrained are higher with offsetting reductions in adjacent hours, which properly allocates the additional system costs imposed by the ramp. Storage can also reduce the extent to which generators must incur costly startups and shutdowns. These benefits are not captured in the market, since these non-convex startup and shutdown costs are not signaled by LMPs. O'Neill et al. (2005) develop a pricing scheme that signal these non-convex cost benefits, however their method is computationally

[3] Ice Energy has recently adopted this approach. An informational brochure describing their business model is available at `http://www.ice-energy.com/stuff/contentmgr/files/1/e652fc8cfc87e0e60b6aac10a6f4f61c/misc/cm_utility_pdf.pdf`.

[4] A press release detailing the installation is available at `http://www.ice-energy.com/content10197`.

burdensome (it requires the SO to determine the optimal dispatch of the generators and storage, and computes prices from this optimized schedule) and the pricing scheme is discriminatory. Thus these two storage benefits can be significantly undervalued in the market, due to computational limitations and market design considerations.

Where markets do not exist it is incumbent upon the utility to calculate the benefits of storage compared to the alternatives and demonstrate that storage is a prudent investment to the relevant regulatory bodies. Capacity-expansion and other planning models used by utilities struggle to capture the benefits of storage to the system, particularly those that capture dynamic benefits involved with AS and system ramping over various time frames (these issues are discussed further in section 2.2). However even where markets do exist, it may be difficult to estimate potential revenues under the uncertainty of scheduling and operating an energy storage device.

It is fairly straightforward for a conventional generator that is considering entering a market to compare the average dispatch price of the generator to historical market prices. Estimation of potential AS revenues is also possible by considering the opportunity to operate the unit at part load and consider the opportunity costs of avoided energy generation. Potential revenues can then be compared to plant carrying and maintenance costs, considering the risks associated with fuel price fluctuations and other factors. However estimating the potential revenues from storage operations is further complicated by the continual need to optimize the storage device, deciding when to buy, hold, and sell energy and other services under the uncertainty of market prices and conditions over multiple time scales.

2.2. Valuation of Benefits

As discussed in section 1, storage can potentially provide a wide range of services, such as those listed in table 1, and many of the values are 'capturable' in existing restructured markets. EPRI-DOE (2003); Eyer et al. (2004); Eyer and Corey (2010); Denholm et al. (2010) provide overviews of these different services, as well as some generic ranges of their potential value using historical market price data. Despite these and other works examining storage applications, our understanding of and ability to quantify some of these values is still quite limited, especially considering combinations of applications.

One issue with valuing storage is that most analyses consider only one or two closely-related storage applications, while it is widely noted that maximizing storage value will likely require multiple value streams. For example, many studies focus mainly on energy arbitrage, examples of which include the works of Graves et al. (1999); Figueiredo et al. (2006); Walawalkar et al. (2007); Sioshansi et al. (2009); Sioshansi (2010); Sioshansi et al. (2011); Schill and Kemfert (2011). These studies often conclude that arbitrage is unlikely to support the high capital costs of most energy storage technologies. A number of these studies further use historical data to estimate an added capacity value, which would be applicable in restructured markets that include supplemental capacity payments, also suggesting that storage is still often uneconomic, though in some cases storage investments can be marginally economic. Studies of other applications include the work of Walawalkar et al. (2007), who examine the value of storage providing AS. They show that among different AS products, regulation is the most valuable, followed by spinning and non-spinning reserves. Regulation is also attractive for energy storage since it is in theory a zero net energy service in the long run, and requires a limited amount of storage capacity compared to most other services. Nourai (2007) examines the value of using storage to relieve a distribution bottleneck thereby deferring distribution investment. An issue that these types of storage analyses raise is the overreliance on historical data. This can be problematic because the market for some of the services considered may be 'thin,' which can result in their values being overstated. For instance, although it is the highest-value AS, the average hourly demand for regulation capacity in the PJM market during the summer of 2011 was less than 1000 MW. Thus the market may only support a limited amount of storage providing regulation services. Moreover, if storage investors act on the same underlying historical price data, a glut of storage may enter the market. Models that can capture the effect of storage on the market are needed to better address these kinds of issues.

While examining these other applications may show additional benefits, and indeed in some cases shows storage to be potentially cost effective (particularly provision of regulation reserves), existing analyses are still limited in that they typically only consider a single application. This highlights the need for more comprehensive analysis that considers multiple applications that may reveal more favorable storage economics. Analyzing multiple applications presents modeling challenges, however, since it requires simultaneous co-optimization of multiple services. This is because different storage applications can compete with or complement one another, implying that their values can be sub- or super-additive. Thus adding values from individual storage studies is generally not appropriate. For example, using storage for AS can reduce its ability to provide arbitrage in subsequent hours if it has to discharge AS-related energy. Although some studies have taken first steps in examining multiple storage applications, these often neglect these types of interactions between services, including the complexity of operational decisions involving multiple services. Sioshansi and Denholm (2010a,b); Drury et al. (2011) study the value of arbitrage and spinning reserves, however they explicitly neglect the effect of AS calls on the ability of storage to provide energy in subsequent hours. They justify this assumption by the fact that spinning reserves tend to be called infrequently, nevertheless this limits the robustness of their estimates. Moreover, regulation tends to be called quite frequently in real-time, meaning that such considerations must be modeled to accurately capture the full AS value of storage. He et al. (2011) examine storage use for multiple applications, although their focus is on designing a set of sequential auctions to coordinate such use rather than an integrated modeling approach.

Another limitation of the existing literature is that many analyses neglect the effect of market and system risk and uncertainty. Instead, they rely on perfect-foresight assumptions, whereby all pertinent state variables (*e.g.* prices, renewable generation) are known *a priori*. This potentially understates the risk and overstates the revenues obtained by a real storage plant developer. Lund et al. (2009); Sioshansi et al. (2009, 2011); Sioshansi and Denholm (2010a); Drury et al. (2011) bound the effect of the perfect-foresight assumption on arbitrage values by examining a 'backcasting' heuristic, whereby storage operations are optimized in an ongoing rolling fashion using historical price data, demonstrating that such simple techniques can be highly effective. Mokrian and Stephen (2006) develop stochastic and dynamic programming approaches to maximize expected arbitrage value when facing future price uncertainty. While such techniques can be successful at capturing potential storage revenues, the amount of net revenue available over the life of a storage asset (and thus the overall return on the asset) can be highly uncertain and more difficult to estimate and model. An important limitation of these works, however, is that they focus exclusively on price uncertainty. Depending upon the application being studied, other forms of uncertainty may be more pertinent. Moreover, when analyzing multiple storage applications, uncertain state variables can cause adverse interactions between different services. Numerous factors such as, energy prices, system contingencies, and renewable generation, can affect the state of charge of storage and the feasibility of a planned schedule of services. Although some modeling work, such as that of Powell et al. (2011), is being done in this area, there is a significant need for analysis and models that can better capture the technical capabilities of storage and the effect of market and system risk and uncertainty. This is especially true in light of the fact that storage developers are often small startup ventures, with limited resources to develop their own modeling and valuation methodologies.

A third issue with existing storage valuation techniques is that they typically neglect strategic behavior on the part of a storage operator and assume storage behaves in a perfectly competitive manner. Many arbitrage analyses implicitly make this assumption by using static prices that do not respond to storage charging and discharging. In other cases storage is analyzed using a production cost model that optimizes generator and storage dispatch decisions to minimize system costs. Some analyses, such as the work of Sioshansi et al. (2009); Sioshansi (2010, 2011); Schill and Kemfert (2011), relax the competitive assumption and examine arbitrage use by a strategic entity. These analyses demonstrate that the static price assumption can overstate arbitrage values, due to the effect that storage could have in suppressing price differences. Thus a profit-maximizing storage operator could underuse storage compared to the welfare optimum. This suggests that new contract structures could be used to fully exploit the social value of a storage deployment. Sioshansi (2010, 2011); Schill and Kemfert (2011) further demonstrate that storage can have negative social welfare impacts, depending upon market structure, that would not be fully captured by the competitive assumption. These results show that modeling strategic behavior can be important in fully understanding the private and external value of storage.

Another area of interest is storage's role in enabling greater penetrations of variable renewable sources. Storage can help reduce renewable curtailment, which can occur due to transmission or operational constraints. An example of the former is the roughly 1.4 GW of wind that interconnected in the McCamey region of Texas in 2001 and 2002, despite there only being about 400 MW-e of transmission capacity. LCRA (2003) estimates that this resulted in about 380 GWh of wind generation being curtailed at an estimated cost of more than $21.4 million in 2002. Furthermore, Wiser and Bolinger (2011) note that in 2010 about 3.5% of potential wind generation in the United States (and 8% in Texas) was curtailed, mostly due to transmission constraints, but increasingly due to minimum generation constraints on thermal generators during periods of high wind and low load. Co-locating storage with renewables can relieve the constraint forcing curtailment—Denholm and Sioshansi (2009) demonstrate that storage can be an economic alternative to transmission for renewable interconnection, while Tuohy and O'Malley (2011) show that adding storage to a system with high renewable penetrations can alleviate generator constraint-related curtailment. The literature occasionally discusses other synergies between renewables and storage. However, there are a limited number of analyses that perform detailed simulations of the impact of renewable deployment on storage value using utility-grade simulation tools. For example, GE Energy (2010) found new PHS to be generally uneconomic even, at a renewable penetration of 35% on an energy basis. However the analysis only examines energy arbitrage and does not consider any ancillary services or capacity benefits, in large part due to modeling challenges. As a result of the difficulties of performing detailed simulations, some estimates of renewable/storage synergies attempt to evaluate individual value streams or 'coupled' applications. An example of this is 'firming' a variable renewable generator. This is something of a canard, in our opinion, since this service would likely be procured in some combination of balancing energy and AS markets and would not be a separate storage application. Indeed, directly coupling storage to a particular renewable generator can yield inefficiencies, since other resources (including other renewables) may be able to counterbalance this variability to some extent. Given the need to evaluate the role of storage in the system as a whole, there is a growing need to better define the role that storage will have in renewable integration and model the value of these services.

3. Regulatory Treatment of Storage

Recent years have seen a shift in the electricity industry away from the traditional vertically integrated utility model toward restructured markets. Because the momentum in market restructuring has stalled, both types of markets are likely to be important within the United States in the near term. Thus it is useful to recognize that storage deployment challenges need to be considered under different market environments, each of which poses its own unique challenges.

In a traditional regulated market, utilities typically rate base generation, transmission, and distribution investments that are shown to be prudent and provide a desired level of system reliability. Storage investments should thus be made in a similar manner—if the utility shows storage to be the least-cost alternative to provide a necessary service (*e.g.* using capacity-expansion models), then the utility could rate base the investment. This is currently difficult to do in practice, however, due to the limitations of capacity expansion models in capturing the value of storage.

Storage investment presents unique challenges in restructured markets, due to the system being operated in a hybrid fashion between cost-of-service regulation and complete reliance on markets. The hybrid design arises because while some electricity services can be provided through competitive markets, others cannot due to natural monopolies, market power, or other factors. The hybrid model can be seen, for instance, in generation services being traded in markets whereas transmission investments and upgrades are largely rate based. Because of this hybrid arrangement, regulatory decision making in restructured markets traditionally classifies an asset as either generation, transmission, or distribution. Whether costs should be recovered through the market or rate base is determined by this classification, and this poses particular challenges for storage because it can have all of these characteristics.

As we suggest in section 2, such a treatment can undervalue storage, since it neglects storage's ability to provide multiple services that cross between these roles. The 20 GW of PHS built in the United States in the 1970s did not suffer from this issue, since these investments were proposed as low-cost alternatives to peaking generation and were thus viewed exclusively as generation assets. Under cost of service regulation, PHS was seen as a prudent investment for provision of firm system capacity, especially compared to expensive natural gas- and oil-fired units and the anticipation of continued high prices for fossil fuels. Large PHS plants were planed and developed similar to other capital-intensive generation assets (such as nuclear plants) and even shared or co-owned by multiple regulated utilities. As natural gas prices dropped new PHS developments became less cost competitive, especially when not valuing many of the ancillary benefits of storage technologies. More recently, however, developers and regulators recognize that storage can provide multiple services. Nevertheless, regulatory decisions still rely on the traditional classification of assets, which may not fully reflect the value storage. Two recent FERC rulings suggest that whether a storage developer plans to exclusively provide regulated services can determine what cost recovery mechanism is used. This raises the question of whether it is beneficial from a regulatory standpoint to have a more flexible treatment of storage that reflect its generation, transmission, and distribution characteristics, or to risk seeing the market not provide the socially optimal amount and operation of storage.

The first case concerns the proposed Lake Elsinore Advanced Pumped Storage (LEAPS) plant in southern California.[5] The developer, Nevada Hydro, proposed building the 500 MW LEAPS plant along with a new transmission corridor between the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) service territories. Nevada Hydro claimed that both projects provide transmission benefits—the new corridor increases transfer capacity between the SCE and SDG&E regions while LEAPS relieves transmission by shifting loads from congested to uncongested periods. Because of the transmission benefits, Nevada Hydro requested that its investments be rate based. Nevada Hydro also proposed a novel operational arrangement whereby the California ISO (CAISO) would dispatch LEAPS to maximize transmission relief benefits. While the FERC allowed the transmission corridor to be rate based, it denied Nevada Hydro's other requests. It concluded that the CAISO dispatching LEAPS would jeopardize the independence required of a market operator, since this would be akin to it owning and operating generation that can affect the market. Moreover, the FERC concluded that since LEAPS would provide its transmission service by participating in the energy market, it would not exclusively be a transmission asset. Thus it concluded that it would be inappropriate to rate base an investment that it viewed as providing generation services, which should instead recover costs through the market.

The second case concerns a set of batteries that Western Grid planned building in California.[6] Western Grid proposed using the batteries to provide voltage support, address thermal overloads, and provide other transmission-related services. As with the Nevada Hydro case, Western Grid requested that its investment costs be rate based because of the transmission benefits of the project. Unlike the Nevada Hydro case, Western Grid was explicit in stating that the batteries will only provide transmission services as instructed by the CAISO and would not participate in any energy or AS markets (*i.e.* their operation would be governed solely by transmission needs stipulated by the CAISO, and not on the basis of market price signals). Western Grid further stated that the batteries would be operated by the CAISO in the same manner as capacitors that address transmission, and as such would not disrupt the CAISO's market independence. Unlike with the Nevada Hydro case, the FERC granted the rate basing requested by Western Grid.[7]

Taken together, these cases suggest that a storage developer must demonstrate that the asset will be used solely to provide regulated services (*e.g.* transmission or distribution relief) for the investment to be rate based. Moreover, for storage to be eligible for rate basing it cannot provide these services in a market-based manner, for instance by using congestion price signals to determine its dispatch. This forces storage developers to choose between one of two dichotomous regulatory structures, both of which may result in inefficient storage use and investment. One is to use storage exclusively for a regulated service and rate base the investment, such as in the Western Grid case. This approach can, however, result in inefficient use of storage that could otherwise provide non-regulated services. Indeed, one of the CAISO's objections in the Western Grid case was that limiting the batteries to capacitor-like operation would force ratepayers to pay for batteries without realizing their full value. Because this approach forecloses storage from capturing market-based value (*e.g.* from energy, AS, or capacity sales), it can also result in inefficient storage investment.

[5]See FERC docket numbers ER06-278-000 through ER06-278-006 for all of the associated filings and rulings.

[6]See FERC docket number EL10-19-000 for all of the associated filings and rulings.

[7]Although the FERC did not grant all of the incentive rates that Western Grid sought, this ruling is substantively different from the Nevada Hydro case in that it allowed rate basing of the investment costs.

This would occur if storage would be an economic alternative to a transmission or distribution upgrade when these other market-based values are included, but would not be without such values. The alternative approach for a storage developer is to capture the value of its services exclusively from the market, thereby foregoing rate basing. As we discuss in section 2.1, however, electricity markets do not provide price signals for the full range of services that storage can provide. Moreover, some services, such as transmission relief, may not be priced efficiently. Thus, unless a storage investment can only provide services that are priced in the market, this approach may yield inefficient levels of storage investment. Under both approaches, however, storage will tend to be undervalued relative to alternative technologies that can provide regulated services. This is because storage must either recover costs through the market, placing it at a competitive disadvantage relative to rate-based transmission and distribution upgrades, or it must forgo market value to earn a rate base.

Since these inefficiencies stem from treating storage as either a regulated or market asset, and because neither treatment fully values storage, it is natural to consider a regulatory scheme that separates the two types of value streams from one another. One approach would be to adopt the open access model that FERC currently applies to natural gas under order 636 and which He et al. (2011) consider. Under such a model, a storage owner would sell storage capacity to third parties, for instance through an ISO-coordinated auction. The third parties could then put their storage capacity to different uses. For instance, an industrial customer purchases capacity to reduce retail energy costs by arbitraging diurnal price differences while a transmission operator uses capacity to provide voltage support. Depending on whether each counterparty is using the storage capacity for a regulated or market service, these costs could be rate based. In the previous example, for instance, the transmission operator would apply for rate basing of its storage costs while the industrial customer would incur the cost of the storage capacity against any energy savings that it realizes. This scheme should efficiently value a storage investment, so long as the capacity is competitively auctioned in order to realize its maximized value. Moreover, it is attractive from a cost recovery standpoint since the market and regulated values of the services can be separated from each other by each counterparty to the storage owner. The primary obstacle to adopting such an approach would likely be financial. Since most technologies are capital-intensive, a storage developer would likely require long-term contracts to be in place before making an investment. Regulated counterparties may, in turn, be reluctant to engage in such contracts due to regulatory risk, for instance if a regulatory body finds that storage capacity is not a prudent investment. Despite these potential issues, such an open-access scheme may prove to be an attractive regulatory framework for storage.

4. Risk and Uncertainty

The current regulatory treatment of storage adds significant risk and uncertainty to the deployment of new storage technologies. Moreover, revenue and technology risks appear to be significant barriers to storage development, regardless of the regulatory structure.

While storage investment in a regulated market only requires a utility to demonstrate that it is prudent, Narayanamurti et al. (2011) note that there is a lack of incentives in regulated markets for deploying new technologies. This issue may be exacerbated by the challenges of analytically demonstrating storage value, as discussed in section 2. For example, Sioshansi et al. (2009, 2011); Drury et al. (2011) demonstrate that storage can face revenue uncertainty, by showing that net arbitrage revenues can vary by a factor of up to five from year to year. This type of uncertainty can add to the difficulty of demonstrating the prudence of a storage project. Nevertheless, if a utility is able to demonstrate this, which it may be able to since storage can reduce the variability of consumer costs, it should be able to earn a rate of return on its investment. Moreover, this rate of return can be largely independent of any value generated by the storage asset *ex post*, although novel regulatory mechanisms such as performance-based rate making, which are surveyed by Comnes et al. (1995), can tie the two together. Thus storage in a regulated market (or allowing storage to be rate based in a restructured market) should reduce the riskiness of the investment, implying a lower discount rate and higher net present value, as argued by Sioshansi et al. (2011), who also show that the breakeven cost of energy storage could be reduced substantially. Although the storage project is less risky to investors in such a regulated framework, the overall risk associated with the investment and operation of the asset is not necessarily reduced, since ratepayers may have greater exposure to risks such as cost overruns and technical shortcomings.

While in regulated markets a utility that demonstrates storage is prudent receives an established rate of return, restructured markets expose merchant developers to the full risk of these capital-intensive technologies. As a result of these added risks, the discount rate required for such an investment will increase, which will tend to reduce the net present value of a potential storage project. Thus a storage project that is marginal under a regulated setting may be a poor investment in a restructured market. Such storage projects are subject to additional sources of revenue risk that contribute to the higher discount rate. One is the regulatory treatment of storage, including the issues raised in section 3, uncertainty surrounding how a particular regulatory proceeding may be determined (*e.g.* determining whether the proposed project will be rate based or not), and the future evolution of storage-related regulation. A second related issue is the effect of future changes in market rules on the ability to capture value streams. For example, Kaufman et al. (2011) note that PJM, the New York ISO, and Midwest ISO recently updated their tariffs to allow storage to participate in the AS markets. Uncertainty leading up to this rule change likely hindered storage development. A third important issue is the thinness of markets for some services, and the effect of market entry (by storage or by competing technologies or services) on these markets. A fourth issue is uncertainty in the time to build a storage project and the state of the market and system, including the generation mix, when complete. A fifth is risks associated with deploying a new technology, including how long the effective asset life will be, what potential cost or technology improvements may come in the near future, and related first of a kind issues, which are discussed by Narayanamurti et al. (2011). These issues can make it worthwhile for some investors to defer an investment decision today and wait for future technology improvements which would be expected to improve storage economics.

Economic deployment of renewable generation is largely based on a combination of incentives, such as investment tax credits (ITCs) and renewable portfolio standards (RPSs). These types of programs can be applied to storage if it provides value that is not properly reflected by the market. Examples of incentive programs in the United states include a federal 30% ITC for new storage investments, which was proposed in 2010. An example of a storage standard, which is similar to an RPS, is California Assembly Bill 2514, which requires certain utilities to install storage devices to meet standards that will be determined by the California Public Utilities Commission by March 1, 2012.

While market and regulatory risk and uncertainty are important barriers, technology risks also remain a very important barrier for storage deployment, as very few storage technologies have been deployed at scale, and backed by established manufacturers. Moreover, technology risks are important barriers to storage deployment in both regulated and restructured market settings. There are a number of examples of storage technologies that appear to be technologically viable, yet reluctance from developers to 'go first' has resulted in significant delays in technology deployment. One example is CAES, seen as the primary alternative to PHS, and likely the lowest-cost bulk-storage technology. While the McIntosh CAES plant is highly successful with well documented reliable operation and based on mature gas turbine technology, construction of a second plant in the United States has yet to occur. Part of the challenge is the geologic requirement. The McIntosh cavern was developed in domal salt, which Succar and Williams (2008) note is uncommon outside of the Gulf of Mexico region. The real promise of CAES is likely deployment using saline aquifers, depleted gas wells, and other porous rock formations. However little research has been historically devoted to development of these formations, and to the authors' knowledge only two formations (one in Pittfield, Illinois and the other in Dallas Center, Iowa) have been thoroughly evaluated for possible CAES applications. The proposed Iowa facility was canceled in July, 2011 due to insufficient geologic conditions after five years' testing and considerable expense of over $8 million, representing another setback to the deployment of a new generation of CAES plants. This adds to the list of greatly delayed or canceled CAES projects, including the fully permitted Norton Energy project in Ohio, where the use of a depleted hard rock mine largely eliminated the geologic risk component.

Other less mature technologies, such as liquid electrolyte flow batteries, face even greater challenges, as demonstrated by the limited deployment to date. The largest planned facility, a 15 MW, 120 MWh flow battery, based on the sodium bromine 'Regenesys' technology was actually partially completed by the Tennessee Valley Authority in 2001. EPRI-DOE (2004) notes that a substantial fraction of the plant, including electrolyte tanks and the power electronics building, were constructed before the battery manufacturer canceled delivery of the core battery components. Other flow battery technologies, such as vanadium redox, have seen multiple iterations offered by multiple vendors. This 'vendor risk' appears to be a strong consideration for utilities considering new technologies, with Nourai (2007) noting this as a factor in American Electric Power's (AEP's) decision to pursue sodium-sulfur (NaS) batteries.

A number of solutions to help mitigate risk-aversion in the utility sector have been proposed, and a common one is demonstration programs supported by government agencies. Until recently, however, there was little research, development, and deployment (RD&D) support for stationary storage technologies. For instance, Boyes (2006) notes that from 1992 through 2008 the annual budget for the Energy Storage Systems Program within the United States Department of Energy's Office of Electricity was typically less than \$10 million per year, with a large fraction of the research congressionally directed. While there were some state RD&D activities, these were limited in scope. Examples include the New York State Energy Research and Development Authority (NYSERDA), which has supported demonstration programs for flywheels and several battery technologies, and the California Energy Commission, which has supported several storage demonstration projects (Huff (2010) provides further details of the NYSERDA program). In 2010 the Office of Electricity's Storage budget was increased to \$14 million, and the American Recovery and Reinvestment Act (ARRA) of 2009 greatly increased funding for storage RD&D through several programs. Applied research is supported through the Advanced Research Projects Agency–Energy program, with \$30.6 million and \$37.7 million awarded for fiscal years 2010 and 2011, respectively. Electricity storage demonstrations were funded directly through the ARRA with total funding of \$185 million. Johnson (2010); Christy (2010); Roberts and Harrison (2011) provide details regarding these funding efforts. ARRA is further supporting development of CAES in several alternative formations, including a depleted gas well, an alternative salt formation, and had supported the Iowa plant. If successful, these developments should help address part of the geologic risk component of CAES, although demonstration in aquifers remains an important barrier. Other projects will demonstrate a variety of advanced battery types and other technologies. While it is unclear if deployment of only one or two of each type will be sufficient to clear the technology risk hurdle, there does appear to be some willingness for both regulated utilities and independent developers to pursue storage technologies that have been demonstrated even at small scale. A recent pattern of development for several technologies has been an initial small deployment (typically with some degree of government support) followed by larger deployments with reduced or zero support through either traditional regulation or on a merchant basis. Examples include:

- AEP deploying a 100 kW NaS battery in 2002, a 1 MW unit in 2006, three 2 MW units in 2008, and a 4 MW unit in 2009. Other developers have since deployed or proposed other NaS facilities.
- AES Corporation deploying a 1 MW lithium ion battery in 2008, followed by several larger projects including a 32 MW facility in 2011.
- Beacon Power deploying a 1 MW flywheel plant in 2008, which was expanded to 3 MW in 2009, followed by an additional 20 MW facility in New York in 2011. However, the bankruptcy of Beacon Power in late 2011 demonstrates some of the challenges and risks facing a merchant storage developer. These challenges may have been compounded by the fact that Beacon Power was both the device manufacturer and plant developer, exposing the company to both technology-development and market-price risks.

The modular nature of these technologies helps enable the incremental deployment, establishing a technology track record and could demonstrate value to both independent developers and to regulators that indicate storage is a prudent investment.

Even mature technologies such as PHS face risks. PHS projects tend to be very large in size, resulting in large upfront capital costs, compounded by long permitting and construction times, especially considering the uncertain regulatory treatment discussed in section 3. Recent declines in natural gas prices have also made bulk storage technologies of all types less competitive. It should be noted, however, that about 49 PHS projects totaling 37 GW of capacity have been proposed.[8] While a major barrier appears to be capital cost, an element of this cost is the long construction time, and associated risks and uncertainty, especially under changing market conditions and structures—Adamson (2009) notes that FERC permitting alone can require about five years. State and local applications and permitting can further add to this time. Construction times vary, with one recent estimate of four to five years. This results in a 10- to 12-year construction time for new PHS based on current schedules. Adamson (2009) notes, however, that closed-cycle PHS plants could be candidates for a streamlined FERC permitting process, given their lack of interaction with any active body of water. This could reduce licensing and construction times to six to eight years, reducing investor risks. Nevertheless, a six-year construction time is still a long waiting time to make an investment in a restructured market environment.

5. Conclusions

Although technical issues, such as manufacturing costs and device efficiency, are often listed as barriers to storage deployment, numerous policy and market issues are also deterrents. This includes incomplete valuation of the full benefits that storage can provide, the regulatory treatment of storage, and risks associated with storage development. Although this discussion is focused on storage deployment in the United States, many of these issues are broadly applicable elsewhere. As appropriate, we suggest some policy approaches or research agendas that can possibly address these barriers, as well as steps that have been taken to ease storage development. Valuation issues can be addressed through further research and model development, as well as more transparent pricing of energy-system services and provision of price signals and control technologies to end users. The current regulatory landscape in the United States is moving towards a dichotomous treatment of storage as either providing solely regulated services (in which case the cost can be rate based) or having to recover all of its costs through the market. This raises a question of whether a hybrid treatment of storage that can better capture market and non-market services, such as unbundling, can provide more efficient storage development. Government support, such as the use of investment tax credits, and streamlining of the permitting process can help mitigate the riskiness of storage technologies, improve project economics, and lower deployment barriers. While we raise possible policy approaches, we are not advocating any particular position and careful thought must be given to decide what policies would be optimal from a societal perspective.

It is important to stress that even if these non-technical issues are addressed, storage is not necessarily the complete panacea that some advocates suggest. This is because storage must ultimately compete against other policy or technology solutions, *e.g.* DR, transmission and distribution upgrades, and generation. Moreover, as we suggest, many of the non-technical issues that limit storage deployment are likely to raise similar barriers to these competing solutions. Thus, to the extent that addressing these issues can make storage more attractive, it will often improve the economics of these competing technologies. For instance, smart grid-type technologies that enable real-time monitoring, control, and communications between the end users and utilities and SOs can aide the deployment of distributed storage. These technologies can aide the introduction of DR programs, which may prove to be a more economic or attractive alternative to storage for some applications.

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[8] A list of proposed PHS projects in the United States that have been issued pre-permits by FERC is available at `http://www.ferc.gov/industries/hydropower/gen-info/licensing/issued-pre-permits.xls`. Many of these projects are in the early stages of development and information on financing is limited. Many are located in areas without restructured markets; while it is unclear if plants proposed in areas with markets would be developed on a merchant basis without long-term contracts or other mechanisms to reduce investor risk.

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