Integrating Energy Storage Devices into Market Management Systems

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***Abstract*—Intuitively, the integration of energy storage technologies such as pumped hydro and batteries into vertically integrated utility and ISO/RTO-scale systems should confer significant benefits to operations, ranging from mitigation of renewables generation variability to peak shaving. However, the realized benefits of such integration are highly dependent upon the environment in which the integration occurs. Further, integration of storage requires careful modeling extensions of existing MMS systems, which are currently responsible for market and reliability operations in the grid. In this paper, we outline the core issues that arise when integrating storage devices into an MMS system, ranging from high-level modeling of storage devices for purposes of unit comment and economic dispatch to the potential need for new mechanisms to more efficiently allow for storage to participate in market environments. We observe that the outcomes of cost-benefit analyses of storage integration are sensitive to system-specific details, e.g., wind penetration levels. Finally, we provide an illustrative case study showing significant positive impacts of storage integration.**

***Index Terms*—Energy Markets, Energy Storage, Market Management System.**

I. Introduction

ENERGY storage is increasingly regarded as an important, complementary alternative to increased penetration levels of wind and other renewable energy sources when considering capital investments to improve power system reliability and flexibility, and to reduce operations costs [?]. For example, energy storage devices are used to capture and hold energy during periods of low demand, which is then released during periods of high demand. The result is a net reduction in the generation capacity required to serve a particular peak load level, potentially enabling lower capital investments associated with generation procurement. Further, because generators are typically dispatched in order from least to most expensive operating cost, energy storage can decrease fuel costs due to reduced reliance on costly fast-start thermal units. In power systems with large renewable energy penetration levels, storage devices can capture energy during periods of high renewable energy production and release stored energy when needed, reducing both the quantity of conventional generation resources required to mitigate variability in renewables production and the total amount of energy from renewables that is curtailed.

Despite the potential benefits, questions surround the economic viability of energy storage due to the currently high capital costs of the associated technologies. For instance, Nyamdash et al. conclude that storage is not a cost-effective mechanism to mitigate wind power variability when such devices are operated in the context of the day-ahead market in Ireland [?]. In this particular study, storage devices did not provide any ancillary services, with the focus instead on the use of storage to enable wind generation to behave more like a conventional generator. Ultimately, the economic viability of energy storage strongly depends on the details of how storage mechanisms are operated and how their associated services are exposed. Further, as with renewables integration, the benefits of energy storage depend on a variety of characteristics (e.g., renewables fleet characteristics and transmission topology) of the specific power system in which they are operated. The cost effectiveness of energy storage also depends on the scope of the associated cost-benefit analyses. For example, a recent analysis conducted by EPRI demonstrates that energy storage can be economically viable once *all* of the benefits conferred to a power system are considered in the cost-benefit analysis [?]. Such benefits come in the form of energy arbitrage and ancillary services, renewable energy integration, generation and transmission capital cost deferral, and voltage and frequency support.

Beyond the availability of conclusive cost-benefit analyses, other barriers to the widespread deployment of energy storage in power systems include regulatory, economic, and technological challenges. Some of these key barriers are detailed in [?]. For instance, power system stakeholders often do not have experience with or understand all the capabilities that a given energy storage technology may offer. Similarly, utilities, system operators, and investors are often unsure of how to conduct cost-benefit analyses for storage projects, due to potentially complex regulatory structures and market mechanisms, the lack of price signals, or the unavailability of storage modeling capabilities in commercial power system modeling software.

Compounding the challenges associated with evaluating the impact of storage mechanisms on a power system is the issue of integrating those mechanisms into the operational processes – embodied via complex software packages – of a given utility or system operator. Here, integrators and operators face two key issues. The first issue relates to the market processes (if any) associated with a particular power system, while the second issue concerns modeling of storage devices in order to meet certain computational efficiency and accuracy criteria required by the system integrator or operator. In this paper, we address both of these issues, in order to overcome some of the barriers to adoption and evaluation of energy storage discussed

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above. Ultimately, storage integration requires the availability of operational models of storage devices, in order to take full advantage of the potential services they may provide, and a set of market rules that fully exploits the benefits of energy storage and provides commensurate compensation for those services. Further, addressing these issues is a pre-requisite for detailed cost-benefit analyses, which typically rely on detailed simulation of the operational environment into which a proposed storage device may be placed.

The remainder of this paper is organized as follows. We begin in Section **??** by describing the general functions of a Market Management System or MMS, i.e., the software system that performs key market and reliability functions in a power system. In Section **??**, we present simple models to facilitate the integration of energy storage devices into an MMS for use in both regulated and deregulated environments. We then discuss potential benefits associated with energy storage in Section **??**, emphasizing systems with high renewables penetration levels and illustration via a concrete case study. The issue of designing new market constructs to more efficiently support storage device operators is examined in Section **??**. Finally, we discuss the future of energy storage in the context of MMSs in Section **??**.

II. Market Management Systems

A Market Management System (MMS) performs all core resource scheduling functions associated with power systems operations. Examples include day-ahead market (DAM) clearing functions, reliability unit commitment (RUC) processes, security-constrained economic dispatch (SCED), and ancillary service market (ASM) management [**?**]. The specific components of an MMS depend on characteristics of a given operating entity, as discussed below in Section **??**. DAM and RUC functions determine which conventional generation units are online, and for which time periods, during the next operating day – subject to forecasts of load and renewables production. The SCED function is executed in the context of an existing generation unit schedule, and determines dispatch levels for each online unit in the system as actual loads are revealed during real-time operations. The integration of storage into a power system necessarily occurs through the MMS, and – as we discuss below – requires changes to the MMS. The scope of these changes depends on the type of operating entity involved, but in the general case would impact at a minimum the DAM, RUC, and SCED functional units.

An MMS interfaces with other systems such as the energy management system (EMS) and commercial and market information systems (respectively denoted COMS and MIS). The MMS and EMS are central to operations performed by ISOs/RTOs. An EMS is responsible for real-time functions such as processing and monitoring measurements from across the grid and estimating system state, in addition to look-ahead functions such as load forecasting and security and stability analyses under current or future operating conditions.

Figure **??** provides a high-level view of these core systems and their interactions [**?**]. In aggregate, the set of functions performed by an MMS implements the operational and/or

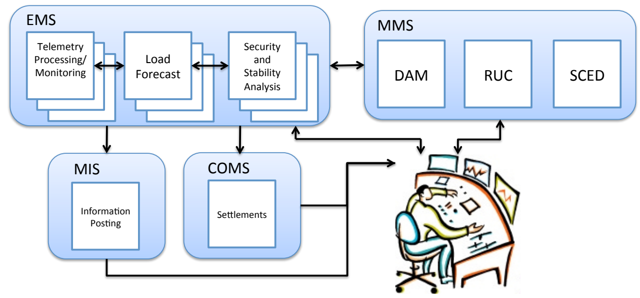

Fig. 1. An overview of power system management software.

market rules established by a system operator. An MMS depends critically on models of generation and other system resources, and these models are instantiated with market and system data. Thus, the integration of a new resource into a power system requires a combination of both resource modeling and potential modification of market rules that allow the resource to effectively participate in the market.

III. Modeling Energy Storage Devices

Power systems in the US are operated in one of two distinct paradigms: as a Vertically Integrated Utility (VIU) or as an Independent System Operator / Regional Transmission Operator (ISO/RTO). A VIU is a traditional, regulated power company that owns or otherwise has some form of control over and visibility into all generation assets in the system. Given such centralized control, DAM, RUC, and SCED functions proceed using known generator heat rates and fuel costs. In contrast to a VIU, an ISO/RTO operates a market in which independent merchant generation companies are allowed to compete. The ISO/RTO has no direct control over generators, and no visibility (beyond the data provided by the market bid structure) into the specifics of their operation. Consequently, DAM, RUC, and SCED functions in ISO/RTO contexts rely on generator energy offers, which specify costs for specific dispatch levels. Analogous processes hold for load in VIUs and ISO/RTOs. In VIUs, load is forecast by the company, and acts as an input parameter to the MMS. In ISO/RTOs, load serving entities (LSEs) submit bids for power, which are cleared concurrently with generator offers. The ISO/RTO then computes its own load forecast when executing RUC functions.

The details of models and operation of energy storage devices clearly depend on the context – VIU or ISO/RTO – into which those devices are placed. The remainder of this section is devoted to presenting candidate, exemplar energy storage models for inclusion in MMS functions, in both VIU and ISO/RTO paradigms.

A. Integrating Storage in a VIU

In a VIU environment, the DAM, RUC, and SCED functions have full control of and visibility into storage device operation. As a result, it is possible to develop models of storage that capture the three main processes associated with unit operation: energy input, energy retention (storage), and energy

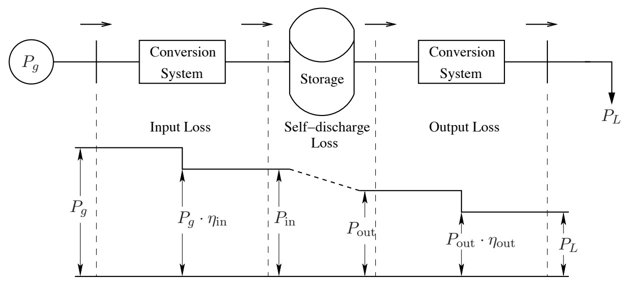

Fig. 2. Energy is lost when flowing from generation through storage to load.

output. Energy storage technologies critically differ in terms of how efficient they are at performing these processes, impacting their operational costs and consequently the applications for which they are economically attractive. For instance, a flywheel requires power electronics and a motor-generator to transfer energy to and from the power system to which it is connected; energy is stored as kinetic energy in a rotating mass. In contrast, pumped hydro energy storage (PHES) systems use pumps and hydro turbines to transfer energy, which is stored as potential energy in an upper reservoir. The input and output processes in a flywheel storage device may be more responsive and efficient than in a PHES because a flywheel's electric drives respond faster than the governor of a PHES. On the other hand, energy retention efficiencies are higher in a PHES than in a flywheel because the rate of water evaporation and leakage over a day is negligible compared to the total water volume in a reservoir [**?**]. In contrast, self-discharge rates in a flywheel are reported to be anywhere between 2% [**?**] and 20% [**?**] of stored capacity per hour. Such differences, depending on device efficiencies, can make PHES better suited for load leveling than flywheels, while flywheels may perform better than PHES units for power regulation and frequency support applications.

The three primary storage processes are illustrated in Figure **??**. In the graphic, energy is shown as flowing left-to-right, as indicated by the arrows at the top of the one line diagram. Energy from a generator flows into a storage device through a conversion system. Examples of such systems include AC/DC power electronics converters in battery energy storage systems and pumps in a PHES. The efficiency of this conversion system can be mathematically represented by the parameter η_{in}, $0 \leq \eta_{\mathrm{in}} \leq 1$. Assuming the generator and storage device are located at the same bus, the power input P_{in} to the storage device is given as

$$P_{\mathrm{in}} = \eta_{\mathrm{in}} \cdot P_g \tag{1}$$

where P_g is the generator power output. For simplicity, we assume no other load is connected to the bus.

Once energy flows into a storage device, self-discharge losses occur. These are illustrated in Figure **??** as a dotted line connecting input and output power levels in the storage device. Self-discharge losses depend on the energy levels and the duration the energy remains stored in the unit. Specific examples of self-discharge losses are friction in a flywheel storage system and water evaporation / leakage in a PHES. The rate of retention of a storage system can be mathematically represented by the parameter η_{sd}, $0 \leq \eta_{\mathrm{sd}} \leq 1$, which is defined in the context of a given time step ΔT. The state of charge (SOC) of a storage device is defined as the amount of energy stored, expressed as a fraction of the total energy capacity of the device. Consequently, $0 \leq SOC \leq 1$. Considering only self-discharge losses, the unit SOC after one time step ΔT is given as

$$SOC(t) = \eta_{\mathrm{sd}} \cdot SOC(t-1). \tag{2}$$

As energy flows from the storage system to the load, it must be transformed into AC electric power via a conversion system. In some cases, a single bi-directional conversion system processes energy both inbound to and outbound from a storage device. In any case, the efficiency of the output conversion system can be mathematically represented by the parameter η_{out}, $0 \leq \eta_{\mathrm{out}} \leq 1$. Assuming the load and the storage device are connected to the same bus, the power output P_{out} of a storage device as a function of the power delivered to the load P_L is given as

$$P_{\mathrm{out}} = 1/\eta_{\mathrm{out}} \cdot P_L. \tag{3}$$

Coupled with constraints on maximum energy storage levels, Equations **??** through **??** can be used to calculate the energy level of a storage device over time, based on the principle of energy conservation. Power system operations are generally modeled using discrete time steps, such that power generation and load are assumed to be constant across a time step. Given this assumption, a storage device's state of charge at the end of a time step of length ΔT is given as

$$SOC(t) = \eta_{\mathrm{sd}} \cdot SOC(t-1) + \frac{\Delta T}{E_{\max}}(P_{\mathrm{in}}(t) - P_{\mathrm{out}}(t)) \tag{4}$$

where $E_{\max}$ denotes the energy capacity of the storage device.

Current MMS technology relies on Mixed Integer Linear Programming (MILP) to settle day-ahead and ancillary service markets, and to solve optimization models associated with RUC and SCED. The storage device model presented above is general enough to represent most storage technologies, and can be easily incorporated in DAM, RUC and SCED optimization models by adding Equations **??** through **??** as constraints, as well as the associated state of charge variables. The latter can be viewed as new decision variables for the VIU, analogous to the generator dispatch level variables presently captured in MMS optimization models. Energy and charge / discharge power ratings must also be modeled via constraints, as must initial and final (goal) state-of-the-charge conditions. Final state of charge targets are required to avoid end-of-horizon effects associated with a finite number of scheduling periods, and are particularly important in intra-day operations. The costs of charging storage devices are explicitly accounted for as increased production costs from conventional generators.

In conclusion, storage devices can be integrated into VIU DAM, RUC, and SCED functions using the above models, in a straightforward and relatively generic manner. However, there remains the issue of how to allocate energy storage capabilities across multiple, distinct services, e.g., arbitrage throughout the day and load following and regulation during real-time operation.

One way for energy storage to provide multiple services is to allow for all services to access energy stored or remaining capacity available. However, if the services are managed in an uncoordinated manner, then some services may be "starved" due to the limited energy capacity of storage units. For example, Silva-Monroy describes an approach to setting state of charge targets in the context of a dynamic or look-ahead (multi-period) SCED, using hourly targets obtained from the RUC [**?**]. Interpolation is employed to calculate state of charge targets at a 5 minute resolution. The final state of charge target is formulated as a constraint, allowing variability in state of charge for intermediate time periods in order to accommodate intra-hour load fluctuations. The net result is increased power system flexibility and an increase in benefits provided by energy storage to the grid.

Another advantage of employing a multi-period economic dispatch is that the optimization captures the value of stored energy by performing look-ahead, as opposed to burdening the user with attempting to directly calculate an appropriate incremental cost curve for storage units, analogous to what is presently performed for conventional generators. Proper calculation of those energy storage incremental cost curves necessary for a single-step SCED is a very difficult task. However, the availability of a rigorous methodology for conducting such computations is very desirable, particularly in the context of integrating storage devices into deregulated markets.

Energy storage can also be employed to provide regulation, i.e., energy used to maintain the load-generation balance of the grid in near real time (i.e., every few seconds). This contrasts to the SCED, which is executed every 5 to 10 minutes. Regulation is performed by an automatic process known as AGC (Automatic Generation Control), whose objective is to rapidly (again, in seconds) make power output adjustments to select online units with available head room in order to maintain energy interchange and system frequency at their scheduled values – while doing so in a cost effective manner. However, due to the fast turn-around requirements, optimization is not employed and an approximation is generally used. One such approximation scheme is that of participation factors, which specify the amount of control action that a generator should be allocated based on its incremental cost in relation to the incremental costs of other online units available for regulation. In other words, the regulation unit with highest incremental cost should be allocated the smallest control action and, conversely, the lowest incremental cost unit should be allocated the largest control action. The participation factor γ for generator g at a given time step t is calculated as

$$\gamma_{g,t} = \frac{\frac{1}{F''_{g,t}}}{\sum\limits_{j \in G^{\mathrm{Reg}}} \frac{1}{F''_{j,t}}} \tag{5}$$

where G^{Reg} is the set of generators participating in regulation with available head room and F'' is the second derivative of the generator cost curve with respect to output power – the slope of the incremental cost curve [**?**]. Because energy storage units do not have an intrinsic generation cost (cost is instead a function of when energy is charged and discharged), Equation **??** cannot be directly applied to storage units. This difficulty can be overcome by using results from two consecutive SCED time steps ($t-1$, t) and calculating the change in energy storage output as a fraction of the change in total output power across all units providing regulation. Mathematically, this given as

$$\gamma_{s,t} = \frac{\Delta P_{s,t}}{\sum\limits_{j \in G^{\mathrm{Reg}}} \Delta P_{j,t} + \sum\limits_{i \in S^{\mathrm{Reg}}} \Delta P_{i,t}} \tag{6}$$

where $s \in S^{\mathrm{Reg}}$ is the set of energy storage units providing regulation, and ΔP is the change in output power between two consecutive SCED time steps, for either generation $j \in G^{\mathrm{Reg}}$ or storage units $i \in S^{\mathrm{Reg}}$ [**?**].

The approach above assumes that energy arbitrage (at an hourly resolution), load following (at a 5-10 minute resolution), and regulation (at a 4 second resolution) functions are equally important to a utility. However, the basic approach can be modified in situations where a utility places greater importance on one or two of these functions. For instance, by making the final state of charge in a multi-period SCED a soft constraint, extra flexibility is gained for load following. Similarly, by increasing the participation factor of a storage device, a greater emphasis on regulation function can be achieved.

Lifetime degradation is another important aspect of storage devices, particularly for battery systems. An energy storage system composed of lead-acid batteries has a lifetime equal to approximately 1500 deep cycles (defined as a drop of 45% to 80% of energy relative to the fully charged state). To avoid rapid degradation, a utility might impose depth of discharge limits and / or restrict use of a device to a specific function, e.g., either energy arbitrage or intra-hour balancing with shallow discharge cycles. As more functions are added, a higher energy throughput is seen by the battery which is equivalent to a higher number cycles over the same time span.

B. Integrating Storage in a ISO/RTO

In the storage device model presented above, a VIU has complete visibility into the state of charge over time, and can precisely control when energy is released or consumed by a device. Further, the cost associated with charging a storage device is explicitly and directly captured by the increase in power output required from conventional generation units. This situation is very distinct relative to that found in deregulated ISO/RTO contexts, where details concerning storage device state and control are abstracted away through the use of market mechanisms.

In an ISO/RTO system, owners of storage devices necessarily act as both generators and load-serving entities. On the generation side, storage device owners produce bids that specify the amount and cost of power that they can supply, and necessarily for how long. Clearly, the latter already imposes minor modifications on market structures. On the demand side, storage device owners submit offers based on their projections of short-term (e.g., daily) storage needs. Clearly, the two sides are linked through the storage device itself, and ensuring consistency between generation and load is significantly more complicated – and potentially much more risky – than in the traditional situations faced by generation and load-serving entities. However, the operational complexity is pushed to the market participants, such that the ISO/RTO DAM, RUC, and SCED functions can in principle remain unchanged following the introduction of storage devices.

Yet, while storage devices *can* be integrated into existing ISO/RTO operations with little impact on current market and reliability processes, this does not imply that existing structures and processes are necessarily optimal or even moderately advantageous for participants operating storage devices. This is a fundamental issue impacting storage cost-benefit analyses, particularly due to the desire to more strongly link bids and offers. Further, there may be incentive to expose additional information regarding storage device states, further complicating the optimization models associated with DAM, RUC, and SCED functions. We revisit this issue in more detail below, in Section **??**.

IV. Building the Case for "Why Storage?"

We now consider potential situations where the addition of storage devices may directly and beneficially impact power system operations, and present a summary of a specific case study. Our intent is to provide exemplars of when introduction of storage devices may be positively impactful, and to illustrate how the associated cost-benefit analyses can be conducted. Our case study focuses on a common and intuitive case for consideration of storage devices: mitigating the variability associated with renewables generation, specifically wind.

As the penetration level of energy obtained from wind resources in a power system increases, the amount of response needed from controllable (thermal) resources also increases, in order to mitigate the inherent production variability associated with wind turbines. If such response is provided from existing controllable generation, as is currently the case, capacity is removed from the day-ahead and real-time markets – potentially deferring energy production required to meet load to more expensive units. Further, the use of controllable resources in a response role results in increased power plant cycling [**?**], which is required to mitigate the potentially significant variability in wind power. The result is a reduction in power plant efficiency and potentially higher maintenance costs due to additional stress on equipment [**?**].

The addition of storage devices into a power system with significant renewables generation can partially mitigate both of these issues. Introduction of storage devices enables relaxation of the operational requirement that power generation must match load (plus losses) at all time periods. Consequently, storage can be used to reduce the degree to which response is provided by conventional generation units, moving those units back into the day-ahead and real-time markets and reducing the variability that they experience [**?**]. Independent of the renewables penetration level, storage can be used to store energy during periods of low demand and release energy during periods of high demand. In this role, storage can serve to both reduce fuel costs and the amount of generation capacity required to serve the same peak load [**?**], [**?**].

Beyond generation, storage devices can beneficially impact transmission systems [**?**]. For example, the introduction of energy storage devices at particular buses can alleviate congestion, allowing deferral of investments in new transmission. When placed near a load center connected through a periodically congested line, storage devices can build energy reserves at times when there is no congestion, and release energy when there is no available capacity on the line. Storage devices can also be used to reduce capacity requirements on transmission lines that may be required when connecting newly constructed wind farms. Specifically, energy can be stored when wind power production exceeds maximum transmission capacity, and released when there is sufficient line capacity. Co-location of energy storage devices with wind farms can also enable control systems to "shape" power output to more closely mirror that of conventional generation units, and provide semi-dispatchable functionality [**?**].

We now analyze the impact of storage devices on power system behaviors via a case study, considering an illustrative power system with 10 thermal generators representative of the generation mix in the Bonneville Power Administration (BPA) balancing area. Transmission constraints are ignored for simplicity and a storage unit with energy and power ratings of 1 GWh and 500MW, respectively, is considered. The latter corresponds in size to a generic pumped-hydro facility.

The system is operated for a one year period for several wind energy penetration levels, varying from 5 to 30%. Wind profiles for each penetration level were obtained by multiplying historical BPA wind profiles [**?**] by a scalar factor. The load profile corresponds to historical BPA energy demand for the same period as the wind profile. In Figures **??** and **??**, we show generator dispatch levels for an arbitrary 24-hour period, for 5% and 30% wind penetration levels, respectively. The top and bottom portions of the figures correspond to scenarios where the posited storage device is respectively absent and present. We analyze the total generation costs and the impact of energy storage on wind curtailment with and without storage, at several wind energy penetration levels. Our analysis is conducted using historical load (L) and wind (W) data from BPA. Our results are obtained from a RUC optimization model using the generic storage modeling constructs introduced above in Section **??**. All stacked graphs show the dispatch of conventional generation (G1-G10), with wind (W) at the top of the stack and load (L) outlining the stack.

In Figures **??**(a) and **??**(a), we see traditional stack graphs in which load equals conventional plus wind generator output at all time periods. In contrast, the introduction of storage into the system allows – when it is cost effective to do so – conventional plus wind generator output to periodically mismatch load, in terms of either surplus or scarcity. This behavior is graphically illustrated in Figures **??**(b) and **??**(b), where the load profile is no longer coincident with the wind power profile. Specifically, we see that the storage device is charged during hours of low aggregate power output by conventional generators. Typically, this occurs at times when marginal prices are low. In contrast, energy is discharged from the storage device during times where aggregate power output by conventional generators is high. These particular hours typically correspond to time periods when energy marginal prices are highest.

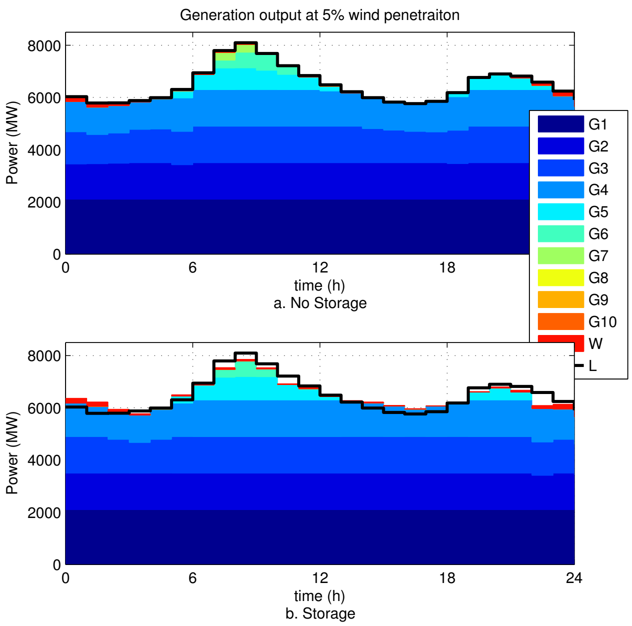

Fig. 3. RUC dispatch results for a 24-hour scheduling period, at 5% annual wind energy penetration with no storage (top) and a 1GWh/500MW storage device (bottom).

When contrasting the generation stack graphs corresponding to operations without and with the storage device, we observe that the presence of the storage device serves to ”flatten” the conventional generation power output profiles. Specifically, the results in Figure **??**(b) show significantly less variability in power output for the conventional generators over time, relative to the results shown in Figure **??**(a). Overall, the storage device helps to compensate for intra-hour variations in wind power, reducing volatility in the power output by the conventional generators. This behavior is a by-product of the SCED MILP solvers concurrently determining (1) dispatch set points for conventional generators and (2) charge / discharge levels for the storage device, with the overall goal of minimizing the total cost of fuel consumed during the time horizon. We note that in no case is there an explicit incentive to compensate for reduction in conventional generation volatility.

Another beneficial impact of the storage device relates to the amount of wind power curtailed. Figure **??** shows the amount of wind curtailed as a function of wind penetration level. The results indicate that as the wind energy penetration level increases, the amount of wind that can be accommodated by the system increases when the storage device is present.

V. Opportunities and Methods for Market Extension and Redesign

As we have discussed, although energy storage devices *can* be and are integrated into existing ISO / RTS markets, this does not imply that such integration is maximally beneficially to those market participants, or even maximally beneficial to the market as a whole. Modern energy and ancillary service markets compensate their participants based on marginal costs. Because energy storage devices do not possess heat rates or steady (over the short term) fuel prices but instead depend on market clearing prices to specify their production costs, there is no straightforward definition of the marginal cost of energy. Energy and ancillary service markets put the onus of creating marginal cost curves on storage device participants, despite their dynamic nature due to dependence on day-ahead and/or real-time prices. Such dynacism yields a complex feedback signal that must be accounted for when computing marginal costs, resulting in greater financial risks for energy storage device operators than for operators of conventional power plants.

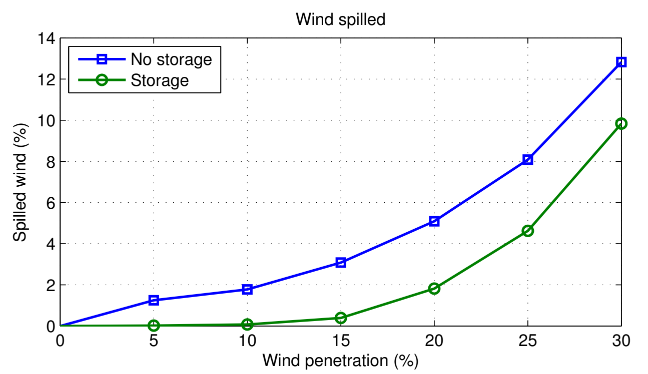

Fig. 5. Wind power curtailment as a function of wind energy penetration, with and without a 1GWh/500MW storage device.

Another example of the difficulty of integrating storage devices into existing market structures arises in capacity markets. Deregulated energy markets compensate conventional power plants for their high capital costs through such markets. As their name suggests, compensation is commensurate with the capacity a generator provides to the system. The purpose of capacity payments is to provide market signals for both new generation to enter the market and to maintain existing generators, in order to avoid generation shortages and thus maintaining grid reliability. Under current market rules, energy storage devices are either ineligible to participate in capacity markets [?] or the market rules fail to provide clarity regarding how storage devices may participate [?].

Moving from the general to the specific, we now consider the situation in which a single energy storage merchant is participating in a DAM. This merchant has no incentive to completely flatten the net energy demand profile for conventional generators, even if the result is lower overall system costs. In this example, revenue for the storage merchant is a function of the difference between high and low marginal prices for hours during which the merchant performs energy arbitrage. When this difference is zero, i.e., when the marginal price throughout the day is stable, storage merchant revenue equals zero. A similar situation occurs in ancillary service markets, where conventional generators are compensated for their energy opportunity cost to provide reserve capacity in addition to the energy supplied when those reserves are deployed. In contrast, the energy storage merchant does not participant in the DAM based on opportunity costs. Consequently, when energy storage can provide all of the necessary ancillary services, the market price becomes zero and the energy storage merchant is left with insufficient revenue to recover their capital cost investment. In general, it is clear that not every resource can efficiently bid into markets in the same manner that conventional generators presently do, driving the need for market extension and redesign.

Further motivating this need is the observation that traditional reserve definitions and requirements can hinder the ability of new technologies such as storage to provide the associated services. For example, reserve ramping products have been recently introduced by several system operators, indicating that the traditional ancillary service markets are failing to meet the needs of a system with significant penetration levels of non-dispatchable resources.

Historically, regulatory requirements have been put into place to induce those changes in market structure required to more effectively support new technologies. In particular, FERC Order 755 [?] requires ISOs and RTOs to implement performance-based pay for work done by the different resources that participate in their energy markets and provide ancillary services. As a result of this regulatory incentive, steps have been taken in some ancillary service markets to provide fair compensation to participants operating emerging grid technologies such as demand response and energy storage. One such example is the Midwest ISO (MISO) regulation market, as implemented in December 2012. In this market modification, MISO partitioned its AGC signal by frequency content into five categories, and now dispatches resources from fastest to slowest. This modification ensures resources are compensated based on the amount of work they perform.

Similarly, existing markets can conceptually be extended to enable more effective and fair participation by storage device merchants. For example, an ISO/RTO could provide for linked bids and offers in order to reflect the need for storage devices to charge and discharge in an coordinated manner. This is a specific example of a more general idea, in which an ISO/RTO is provided visibility into device operational states. Such an approach is clearly more beneficial to storage device merchants than existing mechanisms, which require force-fitting of their operations into standard generator offer and LSE bid formats. The advantage to storage merchants of providing such increased visibility into operational states is the partial mitigation of risk associated with operating storage devices in the market bid/offer process.

Performing incremental modifications to energy market structures, such as those sparked by FERC Order 755, is one approach to integrating new resources and technologies into – now more than ever – evolving power systems. An alternative, more disruptive and potentially beneficial approach is to completely redesign energy market structures from the ground up.

One example of a proposed full market redesign is described in [?]. This redesign addresses existing energy market shortcomings, including many not discussed here, e.g., a shortage of new capacity being built in deregulated regions due to the short-term nature of current energy and capacity markets, which results in high long-term revenue uncertainty [?]. The proposed energy market consists of a succession of linked forward markets with both standardized firm and option contracts. Firm contracts are similar to bilateral contracts in that they obligate the issuer to deliver energy at the time and quantity specified in the contract, and obligate the buyer (i.e., the contract holder) to accept delivery. On the other hand, option contracts allow the holder to exercise the contract (obligating delivery from the issuer) under specific price conditions, generally when the exercise or "strike" price" is lower than the real-time price of the commodity or service. Option contracts are a form of insurance where the procurement price (premium) is paid by the holder in order to compensate the offerer for the risk they take. In the context of energy markets, an option contract is analogous to procurement schemes employed in modern ancillary service markets. Specifically, they allow LSEs and ISOs/RTOs to reserve capacity in advance, from market participants that are willing to defer generation in exchange for a premium.

Contracts in the market proposed in [?] possess a standard set of general attributes that describe the service that the issuer is willing to provide. For firm contracts, the set of attributes is as follows: power magnitude, direction (i.e., up or down), start time, ramp rate, duration, and location. For option contracts, this basic set is augmented with energy capacity and performance payment method. A performance payment method is the offer from the resource, similar to an energy bid, but which can be a function of more than just output power as mandated by FERC order 755 for regulation services. Notice that energy capacity is one of the attributes in option contracts, and is included to provide visibility to the contract holder and ISO into energy-limited resources such as energy storage and facilitate their integration.

Further, the proposed market structure allows the contract attributes to "swing" or vary over a range, as opposed to specify a specific value. For example, an option contract offered with a swing on power magnitude and ramp rate would specify ranges of power outputs and ramp rates that can be deployed from the start time and through the contract duration. Swing attributes permit reliable operation in real-time because they provide the flexibility necessary to maintain the demand-generation balance.

To facilitate firm and option contract trading, a sequential market structure is necessary in order to keep track of contracts entered by market participants and to allow comparison of the resulting portfolio against expected demand. A linked forward market is a sequential series of markets, taking place at various times in advance of real-time operations – at which point all traded contracts are realized and uncertainty is resolved. As with current electricity markets, the forward linked market structure provides ISOs with the ability to maintain system reliability. For example, the structure allows an ISO/RTO to compare the portfolio of firm and option contracts procured by LSEs at a given time to the forecasted system demand for that time, which provides an opportunity to procure additional services through the forward markets remaining until real-time operations. An example of a linked forward structure is found in existing energy markets, and is composed of one long-term forward market (e.g., one- to five-years ahead) where entry of new generation is incentivized, one short-term forward market (e.g., day-ahead) where the portfolio of firm and option contracts is reassessed through updated demand and renewable generation forecasts, and one real-time market (strictly speaking, the real-time market is cleared several minutes ahead of actual operation).

The proposed contract structure allows services to be described in terms of a minimum set of performance-oriented attributes. This contrasts with the situation in existing energy and ancillary service markets, in which services are described in terms of – sometimes arbitrary – power, energy and duration requirements that inadvertently bar some resources from participation. The intended improvements enabled by the proposed market structure include: (1) a leveled playing field for market participants including energy storage merchants, as they can offer services they are best suited to provide based on their individual physical capabilities; (2) greater specificity in reserve requirements, leading to more efficient reserve procurement because balancing needs and can be better matched to a more diverse pool of offers; (3) increased transparency of market operations, by offering a clear path for bi-lateral contracts – which make up the majority of energy transactions today – to fully participate in the market; and (4) improved incentives for investments by increasing the amount of energy and reserves secured through long term contracts. These long term contracts can provide backing when energy storage developers seek financing. All of these improvements provide what we believe to be necessary incentives to encourage wider-spread deployment of not only energy storage devices, but also other new grid technologies (e.g., demand response).

Ultimately, the deployment success of energy storage devices is strongly related to the value they can provide to a power system, compared with other alternatives such as new generation, transmission, or demand response. The efficiency of the markets in which that deployment occurs is critical to evaluating the value of storage, motivating the need for careful consideration of improved market mechanisms to support both storage and other new technologies.

VI. Looking Ahead

The versatility of energy storage devices to function as either a load or a generator is currently an untapped source of flexibility for power systems. Increasing levels of renewable energy penetration on the grid will stress the system while at the same time boosting the value of storage as a source of flexibility. Nonetheless, it is that same versatility that makes energy storage integration into current market systems a complex task. In order to keep pushing the efficiency and resiliency boundaries, the electric grid must be transformed to efficiently integrate new technologies. Market management systems are at the center of this transformation. It is for these reasons as well as current and future technological advances and policy incentives that energy storage will go from rare asset to commonplace resource in power systems.

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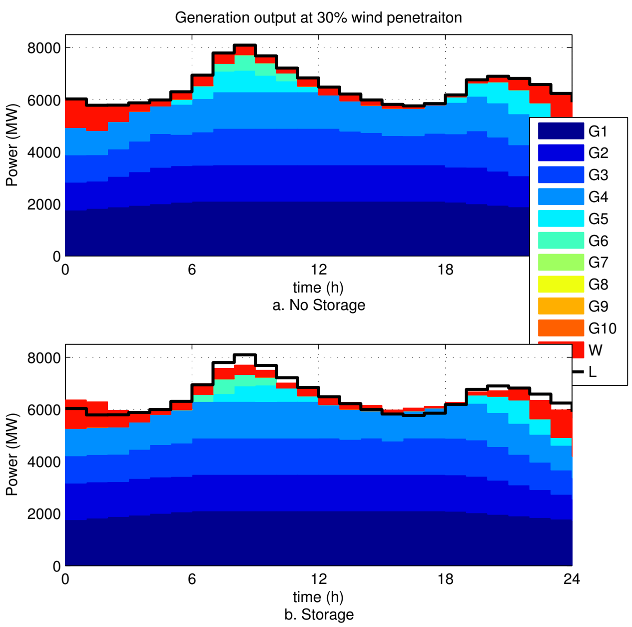

Fig. 4. RUC dispatch results for a 24-hour scheduling period, at 30% annual wind energy penetration with no storage (top) and a 1GWh/500MW storage device (bottom).