Interim Report for Task 4.4: Models and control strategies for optimal control of aggregated FirmPV systems

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February 27, 2011

This is one of three interim reports completed by a UC Berkeley team of students and faculty in the Energy and Resources Group. The overall objective of the project is to determine the impact and value of coupling distributed storage with photovoltaic systems. Our specific focus is on understand distribution system impacts and the opportunity for creating value by incorporating storage into the CAISO's dispatch process.

The tasks of the project are

- 4.2 PV Variability Analysis
- 4.3 - CPP Tariff
- 4.4 - Aggregate control
- 4.5 - CAISO Product

This particular report outlines our efforts to date to understand how to value and control storage in large-scale power systems. The report is written in two parts: *Valuing Storage* (Part I) develops a large mixed integer programming model to understand the value of energy storage in unit commitment and economic dispatch in transmission constrained power systems. *Storage Inventory Control* (Part II) gives an overview of new tools we have developed to control storage systems in distribution networks. The details of this research are currently in review at a journal and will be made available once the paper is in press.

Part I

Valuing Storage

1 Introduction

To determine the potential benefits of FirmPV systems to electricity system operations, it is necessary to develop an accurate operations model for the system, so that any storage and PV benefits can be determined in proper context. We therefore present a preliminary model framework for grid operations, which will be used to identify storage benefits in a wide variety of areas.

1.1 Potential questions answered via the model

We will use this model to answer several questions that characterize the benefits and detriments of adding storage capacity to the electricity grid, including but not limited to the following:

- How can increased storage capacity be used to firm renewables? Are there additional benefits to colocating storage with renewables? Can storage capacity intended to firm renewables provide additional system-wide benefits that are unrelated to renewables?
- What does the demand curve for storage look like? How do costs to operate the system change as the penetration of storage is increased? At what penetration of storage will there be diminishing returns?
- Some areas of the transmission system are congested. How can storage be used to ameliorate congestion? Are there ways for storage to compound the problem? If so, what rules would need to be implemented to avoid this?
- How can we determine the most valuable locations for storage?
- Sensitivity Analysis: How much of an effect on the benefits of storage do the charge and discharge rates and losses for the storage have?

2 Model Description

CAISO currently uses a variety of scheduling and operations models to determine the lowest cost way to meet system demand and reserve requirements. These models are run on a variety of time scales, but can be generalized into two main categories: unit commitment models and economic dispatch models. Unit commitment models identify which units should be running in the future, ranging from a day ahead of time to a few hours in advance. Economic dispatch models identify how the previously scheduled units should be dispatched, given an updated load forecast.

The model we present first runs a unit commitment algorithm based on a simulated load forecast, and then runs an economic dispatch algorithm at each hour based on an updated load forecast. Both models use DC load flow to determine how electricity flows between generators and demand sources. The formulations for the two models are described in Sections 2.1 and 2.2.

2.1 Optimization framework: Unit Commitment

$$\min \sum_{t\in T}\sum_{g\in G} \gamma_{g,t}(q_{g,t}) + N_g * u_{g,t} + s_{g,t} * SU_g \tag{1}$$

$$\text{s.t. } q_{n,t} - L_{n,t} = \sum_{i\in N} Y_{i,n}(\theta_{i,t} - \theta_{n,t}) - \sum_{j\in N} Y_{n,j}(\theta_{n,t} - \theta_{j,t}) \qquad \forall n \in N, t \in T \tag{2}$$

$$Y_{i,j}(\theta_{i,t} - \theta_{j,t}) \leq \bar{Z}_{i,j} \qquad \forall i \in N, j \in N, t \in T \tag{3}$$

$$b_{d,t} \leq \bar{B}_d \qquad \forall d \in D, t \in T \tag{4}$$

$$b_{d,t} = b_{d,t-1} - e^{+}_{d,t} - e^{-}_{d,t} \qquad \forall d \in D, t \in T \tag{5}$$

$$e^{-}_{d,t} \leq M(1 - c^{+}_{d,t}) \qquad \forall d \in D, t \in T \tag{6}$$

$$-e^{+}_{d,t} \leq M(1 - c^{-}_{d,t}) \qquad \forall d \in D, t \in T \tag{7}$$

$$c^{+}_{d,t} + c^{-}_{d,t} = 1 \qquad \forall d \in D, t \in T \tag{8}$$

$$\sum_{g\in G} r^{Up}_{g,t} + \frac{4}{T_L}\sum_{d\in D} e^{Up}_{d,t} \geq \rho \sum_{d\in D} L_{d,t} \qquad \forall t \in T \tag{9}$$

$$\sum_{g\in G} r^{Down}_{g,t} + \frac{4}{T_L}\sum_{d\in D} e^{Down}_{d,t} \geq \phi \sum_{d\in D} L_{d,t} \qquad \forall t \in T \tag{10}$$

$$q_{g,t} + r^{Up}_{g,t} \leq q^{Max}_g u_{g,t} \qquad \forall g \in G, t \in T \tag{11}$$

$$q_{g,t} - r^{Down}_{g,t} \geq q^{Min}_g u_{g,t} \qquad \forall g \in G, t \in T \tag{12}$$

$$e^{-}_{d,t} + e^{Up}_{d,t} \leq b_{d,t} \qquad \forall d \in D, t \in T \tag{13}$$

$$-e^{+}_{d,t} + e^{Down}_{d,t} \leq \bar{B}_d - b_{d,t} \qquad \forall d \in D, t \in T \tag{14}$$

$$s_{g,t} \geq u_{g,t} - u_{g,t-1} \qquad \forall g \in G, t \in T \tag{15}$$

$$0 \leq r^{Up}_{g,t} \leq \bar{R}_g u_{g,t} \qquad \forall g \in G, t \in T \tag{16}$$

$$0 \leq r^{Down}_{g,t} \leq \underline{R}_g u_{g,t} \qquad \forall g \in G, t \in T \tag{17}$$

$$b_{d,t}, e^{-}_{d,t} \geq 0 \qquad \forall d \in D, t \in T \tag{18}$$

$$q_{g,t} \geq 0 \qquad \forall g \in G, t \in T \tag{19}$$

$$e^{+}_{d,t} \leq 0 \qquad \forall d \in D, t \in T \tag{20}$$

$$e^{Up}_{d,t}, e^{Down}_{d,t} \geq 0 \qquad \forall d \in D, t \in T \tag{21}$$

$$c^{+}_{d,t}, c^{-}_{d,t} \in \{0, 1\} \qquad \forall d \in D, t \in T \tag{22}$$

$$s_{g,t}, u_{g,t} \in \{0, 1\} \qquad \forall g \in G, t \in T \tag{23}$$

Constraints:

Number	Description
2	Node Balance constraint: the power generated less load demanded at node n must equal the net power flow at n
3	Power moving along line i, j must be $\leq$ the line limit Z
4	storage level at demand node d in period t must be less than max demand level
5	storage level in current period t at demand node d must equal the storage level in the previous period plus adjustments
6	Amount discharged from storage at demand node d in period t must be 0 if charging, unlimited if discharging
7	Amount charged to storage at demand node d in period t must be 0 if discharging, unlimited if charging
8	storage can be either charging or discharging, not both
9	Sum of upreg from generators and batteries must be greater than or equal to ρ of total load
10	Sum of downreg from generators and batteries must be greater than or equal to ϕ of total load
11	Sum of generation and upreg must be less than max gen, if generator is operating
12	Difference between generation and downreg must be greater than min gen, if generator is operating
13	storage energy delivered plus energy used for upreg must be less than or equal to the current energy level
14	storage energy delivered minus energy used for downreg must be greater than or equal to 0
15	The startup binary variable is 1 if the operating variable is one in this period, but was 0 last period
16	Generator upreg must be less than max generator upreg for generator g
17	Generator downreg must be less than max generator downreg for generator g

Decision Variables:

Variable	Description
$q_{g,t}$	Power generated by generator g in time period t
$u_{g,t}$	Binary variable denoting if generator g is operated in period t
$s_{g,t}$	Binary variable denoting if generator g is started in period t
$b_{d,t}$	storage level at demand node d in period t
$e^+_{d,t}$	Amount charged to storage at demand node d in period t
$e^-_{d,t}$	Amount discharged from storage at demand node d in period t
$e^{Up}_{d,t}$	Energy available for upreg from storage at demand node d in period t
$e^{Down}_{d,t}$	Energy available for downreg from storage at demand node d in period t
$c^+_{d,t}$	Binary variable denoting if storage at d is charging in period t
$c^-_{d,t}$	Binary variable denoting if storage at d is discharging in period t
$r^{Up}_{g,t}$	Amount of upreg supplied by generator g in period t
$r^{Down}_{g,t}$	Amount of downreg supplied by generator g in period t
$\theta_{i,t}$	Voltage angle at node i in time period t (demand or generator)

Constants:

Constant	Description
$\gamma_{g,t}$	Cost coefficient for generator g in period t
$N_{g,t}$	No-load cost for generator g in period t
SU_g	Start-up cost for generator g
$Y_{i,j}$	Admittance between nodes i and j
$L_{d,t}$	Load forecast at demand node d for period t
T_L	timeperiod length
δ_d	Fraction of energy that must be used to charge storage at d
β_d	Fraction of energy that will be delivered if storage d is discharged
$\bar{Z}_{i,j}$	Maximum capacity of transmission line between nodes i and j
$\bar{B}_d$	Maximum capacity of storage d
$\bar{q}_g$	Generation limit for generator g
M	Large constant
$\bar{R}_g$	Maximum upreg supplied by generator g
$\underline{R}_g$	Maximum downreg supplied by generator g
ρ	Percent upreg required
ϕ	Percent downreg required

Sets:

Set	Description
N	Set of all nodes in network
G	Subset of N; set of generators
D	Subset of N; set of demand nodes
T	Set of all time periods

2.2 Optimization framework: Economic Dispatch

$$\min \sum_{t \in T} \sum_{g \in G} \gamma_{g,t}(q_{g,t}) + N_g * u^{UC}_{g,t} + SU_g * s^{UC}_{g,t} \tag{24}$$

$$\text{s.t. } q_{n,t} - LF_{n,t} = \sum_{i \in N} Y_{i,n}(\theta_{i,t} - \theta_{n,t}) - \sum_{j \in N} Y_{n,j}(\theta_{n,t} - \theta_{j,t}) \qquad \forall n \in N, t \in T \tag{25}$$

$$Y_{i,j}(\theta_{i,t} - \theta_{j,t}) \leq \bar{Z}_{i,j} \qquad \forall i \in N, j \in N, t \in T \tag{26}$$

$$b_{d,t} \leq \bar{B}_d \qquad \forall d \in D, t \in T \tag{27}$$

$$b_{d,t} = b_{d,t-1} - e^+_{d,t} - e^-_{d,t} \qquad \forall d \in D, t \in T \tag{28}$$

$$e^-_{d,t} \leq M(1 - c^{+,UC}_{d,t}) \qquad \forall d \in D, t \in T \tag{29}$$

$$-e^+_{d,t} \leq M(1 - c^{-,UC}_{d,t}) \qquad \forall d \in D, t \in T \tag{30}$$

$$q_{g,t} \leq (q^{UC}_{g,t} + r^{Up,UC}_{g,t})u^{UC}_{g,t} \qquad \forall g \in G, t \in T \tag{31}$$

$$q_{g,t} \geq (q^{UC}_{g,t} - r^{Down,UC}_{g,t})u^{UC}_{g,t} \qquad \forall g \in G, t \in T \tag{32}$$

$$b_{d,t} \geq e^{-,UC}_{d,t+1} \qquad \forall d \in D, t \in T \tag{33}$$

$$b_{d,t} \leq \bar{B}_d + e^{+,UC}_{d,t+1} \qquad \forall d \in D, t \in T \tag{34}$$

$$b_{d,t}, e^-_{d,t} \geq 0 \qquad \forall d \in D, t \in T \tag{35}$$

$$q_{g,t} \geq 0 \qquad \forall g \in G, t \in T \tag{36}$$

$$e^{Charging}_{d,t} \leq 0 \qquad \forall d \in D, t \in T \tag{37}$$

Decision Variables:

Variable	Description
$q_{g,t}$	Power generated by generator g in time period t
$b_{d,t}$	storage level at demand node d in period t
$e^+_{d,t}$	Amount charged to storage at demand node d in period t
$e^-_{d,t}$	Amount discharged from storage at demand node d in period t
$\theta_{i,t}$	Voltage angle at node i in time period t (demand or generator)

Constants:

Constant	Description
$u_{g,t}^{UC}$	Generator operation variable determined in UC Model
$s_{g,t}^{UC}$	Generator start-up variable determined in UC Model
$e_{d,t}^{+,UC}$	Amount charged to storage at demand node d in period t in UC Model
$e_{d,t}^{-,UC}$	Amount charged to storage at demand node d in period t in UC Model
$c_{d,t}^{+,UC}$	True if storage at d is charging in period t in UC Model
$c_{d,t}^{-,UC}$	True if storage at d is discharging in period t in UC Model
$r_{g,t}^{Up,UC}$	Amount of upreg supplied by generator g in period t in UC Model
$r_{g,t}^{Down,UC}$	Amount of downreg supplied by generator g in period t in UC Model
$\gamma_{g,t}$	Cost coefficient for generator g in period t
$N_{g,t}$	No-load cost for generator g in period t
SU_g	Start-up cost for generator g
$Y_{i,j}$	Admittance between nodes i and j
$LF_{d,t}$	Updated load forecast for next hour at demand node d for period t
T_L	timeperiod length
δ_d	Fraction of energy that must be used to charge storage d
β_d	Fraction of energy that will be delivered if storage d is discharged
$\bar{Z}_{i,j}$	Maximum capacity of transmission line between nodes i and j
$\bar{B}_d$	Maximum capacity of storage d
M	Large constant

Constraints:

Number	Description
25	Node Balance constraint: the power generated less load demanded at node n must equal the net power flow at n
26	Power moving along line i, j must be $\leq$ the line limit Z
27	storage level at demand node d in period t must be less than max demand level
28	storage level in current period t at demand node d must equal the storage level in the previous period plus adjustments
29	Amount discharged from storage d in period t must be 0 if charging, unlimited if discharging (set by UC)
30	Amount charged to storage at d in period t must be 0 if discharging, unlimited if charging (set by UC)
31	Generation at node g in time t must be less than or equal to the sum of generation and upreg from UC
32	Generation at node g in time t must be greater than or equal to the difference between generation and downreg from UC
33	storage energy level must be at least enough to satisfy the next hour's discharge requirements, from UC
34	storage energy level must be smaller than the difference between the maximum storage level and the next hour's charge requirements

Sets:

Set	Description
N	Set of all nodes in network
G	Subset of N; set of generators
SG	Subset of G; set of slow generators
FG	Subset of G; set of fast generators
D	Subset of N; set of demand nodes
T	Set of all time periods

2.3 Storage participation in reserve and energy markets

Storage capacity can be used to serve multiple electricity system functions, which is a key aspect of storage that is built into this model. In the model, storage capacity can be used in both the energy and reserve markets. From an operational perspective, this means that when storage capacity is in any given charge state, one portion of its stored energy can be allocated to providing reserve, while another portion can be allocated to providing energy that is actually serving demand. Storage devices can serve as up-regulation when they are discharging and down-regulation when they are charging, so they can participate in both markets in addition to traditional energy markets. This is achieved in the model by two constraints: the first constraining the sum of reserve and energy provided by a storage device in a given hour to be at most the total energy stored in the device at the beginning of the hour, and the second constraining the total amount of down-regulation provided to be no more than the difference between the amount used to provide energy and the total available capacity in the storage. At present, the model can only use storage for reserve at a charge/discharge rate equal to the rate the storage device would experience were it to charge/discharge completely. Sioshansi and Denholm suggest that using the fifteen minute discharge rate rather than the current hour discharge rate is appropriate, which would make storage operation in the reserve markets even more lucrative [1].

2.4 Optimal storage location identification

The model can be slightly modified to determine the most lucrative locations for storage. Instead of defining the storage capacity at each node, B_d, as a constant, it is defined as a decision variable. A new constraint is added that constrains the sum of all storage capacity in the network to a particular level:

$$\sum_{d \in D} B_d \leq TotalStorageCapacity.$$

This new problem is solved repeatedly with successively larger $TotalStorageCapacity$ values, and with the addition of a lower bound on the next values of B_d, such that the storage capacity at each node at each successive iteration must be at least as much as the capacity in the previous iteration. In this manner, we can determine optimal storage penetration locations by identifying the system capacity at which each location's capacity becomes nonzero.

2.5 Current model extent and data

The model is currently simulated as a DC load flow on an IEEE 14-bus test system with transmission constraints on lossless transmission lines. Four generators are simulated at two generation nodes in the IEEE bus network, using cost curves from E3 [2] and scaled load curves from an IEEE WECC market test system [3]. The four generators simulate nuclear, gas, biomass, and geothermal plants of equal capacity at 5 MW. Demand is identically distributed over twelve demand nodes, and its total peaks at 16 MW in the unit commitment model. Load forecast errors are updated and simulated for the economic dispatch model [4] [5]. At each demand node, a 1 MWh storage device is present, with charging and discharging losses of 10%. Each device is assumed to be capable of fully charging and discharging hourly. The cost to operate these devices is derived from the cost of the energy used to charge them, but no additional investment costs are modeled.

2.6 Model Implementation, Algorithms, and Run Times

This model was developed in AMPL, a high-level mathematical programming. AMPL compiles the mixed-integer linear program and passes it to CPLEX. The CPLEX version currently in use is CPLEX 12.0. CPLEX uses a branch-and-cut algorithm to solve the optimization, progressing through a tree of linear programs and using the simplex method at each node. The current runtime for the model is approximately two seconds. This time should increase exponentially in the number of binary decision variables; presently there are 768 binary variables in the model.

2.7 Model Expansion

This model will be expanded to cover a 225-bus model of the CAISO system [6].With this expansion, the model will be run using demand profiles and forecast errors from different times of year, which will allow the model to investigate the benefits of storage as load profiles change. Intermittent resource models will also be added from other work completed for this grant. Such resources will be located at demand nodes both with and without storage, so that the effects of colocation of storage and intermittent resources can be examined.

3 Results Description

The results for this model take the general form of operation instructions for each generator and storage device in each hour, as well as the cost to operate the system based on the start-up, operating, and fuel costs of each generator. As parameters of the model are varied, the cost to operate the system changes. We can therefore develop a relationship between the cost to operate the system and the changed parameters.

3.1 Preliminary results

Using the current extent of the model, the unit commitment algorithm determines the operation schedule shown in Figure 1. With a larger and more robust model extent, the dynamics of system operation shown here are likely to change significantly due to the additional generators and load centers. Storage operations are still expected to a follow a similar pattern to that shown here; charging in early hours when the system's marginal cost is low and discharging in afternoon and evening hours when costs increase.

As overall storage penetration is increased, the total cost to operate the system is decreased, as shown in Figure 2. Since the storage devices are modeled as fully charging and discharging in an hour, there is no additional benefit for new storage after the total storage capacity reaches the total generation capacity of 20 MW. As the model is expanded, the 3% percent savings observed here is likely to be preserved, and possibly improved upon as the supply curve for generation becomes smoother and steeper

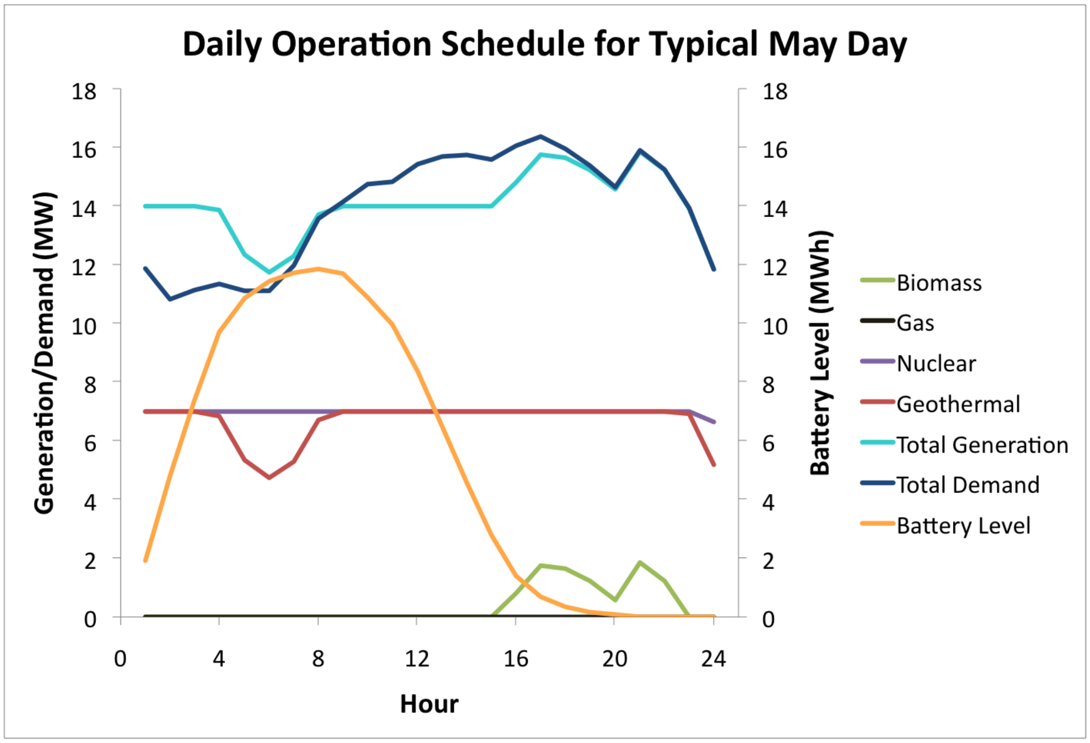

Figure 1: This graph shows the total load for the system, and the operation profiles for the generators and storage devices that provide the cheapest schedule that satisfies load. At the beginning of the day, the storage devices are being charged, so the total generation is higher than the total demand. During the middle of the day, the storage devices are discharged to satisfy some of the demand, so the total generation is lower than the total demand. At the end of the day, the storage capacity has been exhausted, so a biomass plant must come online to satisfy the evening demand peak.

with more generating entities. The costs displayed are relevant to the 14-bus system, and are not likely to be repeated for larger models.

4 Relation of Results to Broader Goals

As this model is expanded, its results will give a clearer picture of the impacts of high-penetration storage on a more complicated electricity system. By examining the differences in optimal generator operations with and without storage, the effects of storage on the system's overall operations can be assessed, from both a cost perspective and a feasibility perspective. By running the model with varying levels of storage penetration, the marginal value of additional storage penetration can be determined.

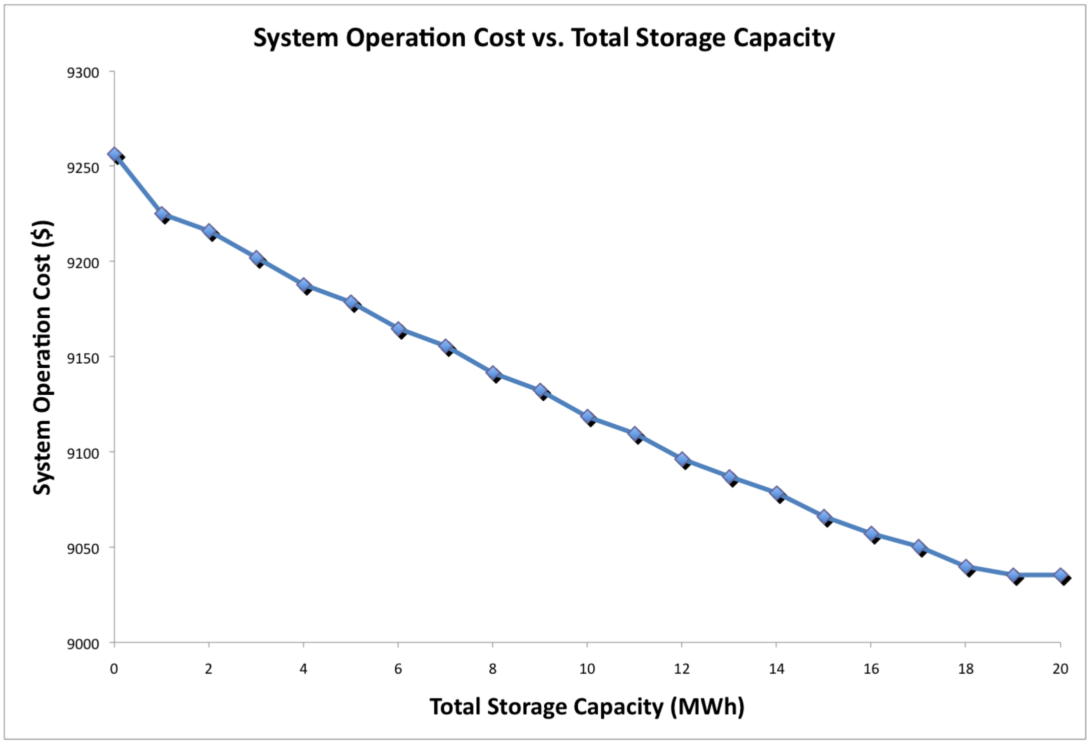

Figure 2: System cost as a function of storage penetration. Overall, system cost is decreased as storage is added. For this system configuration, the relationship between cost and storage capacity is roughly linear. At 20 MWh of capacity, the system cost has been reduced by about 3%.

Part II

Storage Inventory Control

1 Background and set-up

Distributed generators [7], roughly defined as producers of small quantities of power geographically close to the loads they serve, are becoming increasingly common. The advantages of distributed generation are numerous, including microgrid operation [8], enhanced robustness via dispersion of vulnerabilities, reduced substation capacity requirements, and efficient transmission of power due to shorter power flow paths [9, 10]. One of the key obstacles to the integration of distributed wind and solar generators is intermittency: the outputs of wind and solar producers are variable and unpredictable, and require additional flexible resources (or operating reserves) to maintain the supply-demand balance [11].

By co-locating energy storage with distributed generators, intermittency can be balanced locally [12, 13]. This in turn could reduce requirements for transmission infrastructure and operating reserves from the bulk grid. When storage and generation are under the same control, enhanced performance is achievable [14, 15]. However, in restructured or deregulated markets, independent storage agents could enter the market as well. In this case, similar benefits are attainable, but, because generation and storage are not operated by a single entity, the parties involved must agree on some economic terms.

Existing reserve markets capture such economic terms for generators [16, 17], in which a premium is paid for reserve capacity, which may then be purchased at some strike price. Our current focus differs in that storage exists primarily as a reserve, and so does not incur significant opportunity costs [18], and in that standard storage technologies such as pumped hydro [19] and batteries [20] must regularly accept external power to meet their purposes.

In this work, we examine how independent operators of storage might derive profits from absorbing unanticipated renewable variability, and the resulting interaction between storage and a renewable energy producer. Implicit in our framework is a secondary profit channel: inter-temporal price arbitrage. We remark that with the exception of pumped hydro, the latter has not been pursued in practice, because storage inefficiencies and capital costs have outweighed expected profits even under high price volatility [21]. However, the two objectives are seamlessly integrated in our framework, so that any amount of profitable arbitrage will be identified and balanced with absorbing unexpected variability.

2 Results

In our main result, we study how storage can pursue these objectives through scheduled transactions. We find that the optimal storage cost and scheduling policy are piecewise-affine in the current energy level, and are thus easy to compute and analyze. The result is obtained using inventory control theory [22, 23, 24], which has been used to optimize generator reserve management [25]. We deviate from traditional inventory control by incorporating details particular to energy storage, such as physical inefficiencies and hybrid storage configurations [26]. We then use the optimal policy to study the equilibrium between storage and renewable energy producers.

Extensions to the basic framework include simultaneous fee and schedule determination, temporally correlated contract deviations, and network considerations. More generally, control strategies for portfolios of energy storage, as well as game theoretic competitive analysis of storage markets are future objectives.

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