Overcoming Transmission Constraints: Energy Storage and Wyoming Wind Power

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1 Introduction

This study represents a collaborative effort to investigate how energy storage can improve the economics of a wind farm constrained by transmission line congestion. A number of tools were built to analyze the proprietary data and the findings confirm the advantage of installing energy storage to overcome transmission constraints.

1.1 Background

The windy and remote conditions of Wyoming have helped to make it home to most of the major wind farm developments in the U.S. in recent years. Wyoming is a significant exporter of electricity to Western states because power generation from the various local resources, including coal, natural gas, and wind, far exceeds in-state customer demand. Power purchasers such as the Bonneville Power Administration and PacifiCorp use Wyoming wind generation for portfolio diversity and sales to other Northwestern utilities, some of which are required to meet Renewable Portfolio Standards (RPS).[1]

Purchases of power generated in Wyoming to supply out-of-state demand suggest the need for transmission line capacity development in conjunction with Wyoming generator development. However, factors such as separate ownership of generators and transmission lines, and high costs of transmission capacity additions, can temporarily decouple these developments. Transmission line congestion occurs when scheduled power transmissions approach and exceed the established safety limits of transmission line capacity. During periods of congestion, non-firm power generation, such as wind, is the first to be curtailed. In the case of the wind farm analyzed in this project, Foote Creek Rim I, transmission line congestion was identified as a factor that could increasingly limit dispatch. Thus, a key focus of this study was to compare the economic viability of an energy storage system at Foote Creek Rim I wind farm under scenarios with and without transmission line constraints.

Another objective of this study was to incorporate, to the greatest extent possible, measured variation in factors affecting wind farm power deliveries. Projections of power output and revenues from wind farm operations are typically based on average annual or monthly wind speed data, and do not include simulated shorter term variation. Use of datasets with measured hourly wind speed and power generation, such as applied in this study, provide a more accurate view of wind farm operations without overstating the potential benefits of energy storage. The application of hourly transmission line load data to model wind farm curtailment frequency and duration adds another layer of actual variation to this analysis. Together, these detailed datasets were used to conduct an economic assessment of a flow battery at Foote Creek Rim I that incorporated actual variations in wind speed, power generation, and transmission line congestion.

1.2 The Site

Foote Creek Rim is a remote, treeless plateau in Carbon County, Wyoming. Foote Creek Rim is one of the windiest places in America, with extreme temperatures that fall as low as 30°F below zero in the winter. The 41.4-MW Foote Creek Rim I wind farm is one of five wind farm operations on the plateau. There are 69 Mitsubishi 600-kW turbines installed along a three-mile portion of the plateau, with

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[1] RPS goals of 15 to 20% of statewide power to be provided by renewable resources by or before 2020 have been set in the western states of Nevada, California, and Washington.

elevation varying from 7,950 to 7,750 feet. This site began producing power in April 1999, and was the first commercial wind generated power station in Wyoming.

Foote Creek Rim I is owned by PacifiCorp[2] and the Eugene Water and Electric Board (EWEB), and is operated by AES SeaWest.[3] The project pays substantial taxes to the county and state (i.e., $800,000/year is received by the county).[4] Purchasers of power from the wind farm include PacifiCorp, EWEB, and the Bonneville Power Administration. Electrical facilities include a substation, and a 28.8-mile transmission line connecting the facility to the grid.

1.3 Power Transmission and Congestion

In Wyoming, electricity is transmitted primarily from the northeast part of the state to the southwest along PacifiCorp's TOT 4A transmission line. A smaller capacity transmission line in the opposite direction is known at TOT 4B. When the capacity of these lines limits the amount of energy that can be transferred to the western load centers, the grid operator finds other (more expensive) generation sources on the load side of the constraint. During these periods of constraint, or congestion, non-firm generators (e.g., wind farms) are among the first to be curtailed. In 2003, there were a total of 1,686 hours in which load exceeded 75% of the capacity along TOT4, indicating congestion. During 187 of these hours, load exceeded 90% of capacity.[5]

The strained Rocky Mountain regional system and its inability to accommodate new power generation have been addressed by the Rocky Mountain Area Transmission Study (RMATS).[6] Co-sponsored by the Governors of Wyoming and Utah, RMATS was a consensus planning study conducted by regional industry, governmental, and environmental stakeholders in 2004 to examine transmission expansion needs. RMATS recommendations included several projects to increase transmission capacity from inter-mountain states to more densely-populated surrounding states, including:

- The *Frontier Line*, announced by the Governors of California, Nevada, Utah and Wyoming in April 2005. This interstate high-voltage transmission line was proposed to originate in Wyoming with terminal connections in Utah, Nevada and California.
- The *TOT3 Project*, announced in September 2005 by the Wyoming Infrastructure Authority, Trans-Elect, and the Western Area Power Administration to strengthen the electrical tie between Wyoming and Colorado.
- *TransWest Express*, announced by Arizona Public Service in 2006, to reach Wyoming with transmission lines from northern Arizona through Utah.

The Wyoming Infrastructure Authority and National Grid signed a Memorandum of Understanding (MOU) in December 2005 to jointly conduct the Wyoming – West study, which was to help lay the groundwork for a significant increase in transmission capacity between Wyoming and neighboring states to the West. The Wyoming - West study assessed the RMATS recommendations in light of subsequent project announcements, and focused on identifying new transmission needs within Wyoming and between Wyoming and its neighbors to the west. The MOU between National Grid and Wyoming Infrastructure Authority addressed their continued relationship on permitting, financing, construction and operation of

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[2] PacifiCorp was acquired by Mid-American Holding Company in 2006.
[3] Previously SeaWest WindPower of San Diego, this company specializing in wind farm development and asset management was acquired by AES in 2005.
[4] As reported by EWEB at http://www.eweb.org/Home/Windpower/wyoming/foote_creek.htm and by Renewable Northwest Project at http://www.rnp.org/Projects/foote.html on 12/11/06
[5] Further description of constraints along the TOT4 transmission line is provided in Appendix A.
[6] See http://psc.state.wy.us/htdocs/subregional/home.htm.

new transmission lines identified by the study. The time-frame in which new transmission projects come on-line will undoubtedly affect the extent of future curtailment of intermittent power providers such as wind farms.

1.4 Flow Battery Contributions

A large multi-MWh energy storage system that can control energy discharge over hours (as opposed to minutes) could provide Foote Creek Rim I with storage of power generated during curtailment for later sale. Such an energy storage system could also increase the reliability of wind generation during periods of peak demand, thereby enabling the wind farm to seek a conditional firm tariff. PacifiCorp is working with Bonneville Power Administration to develop a Conditional Firm product to be implemented by year-end 2008, enabling wind farms and other intermittent resources to receive the benefits of firm power delivery during pre-determined periods.[7]

The VRB Energy Storage System (VRB-ESS) can provide many hours of electrical energy storage in a vanadium redox regenerative fuel cell (also known as a flow battery). Energy is stored in vanadium ions in a dilute sulfuric acid electrolyte. The reaction is reversible, allowing many charge-discharge cycles and deep discharges. The VRB-ESS can absorb or discharge energy within milliseconds in response to load fluctuations, providing voltage and frequency stabilization. As a result, the VRB-ESS can be used to store power generated during periods of transmission line congestion (e.g., during curtailment), and to release power in response to changes in dispatch orders.

PacifiCorp has been testing a VRB 250-kW/8-hour (or 2 MWh) flow battery at the Castle Valley substation in Moab, Utah. The Castle Valley system is the first flow battery storage system installed and operated in the U.S. For this study, VRB conceptually scaled up the Castle Valley storage system, and re-oriented the electrolyte tanks to vertical to reduce the system's footprint. The conceptual design applied in this study is capable of either 6 or 8 hour discharge.

1.5 Project Objectives

The overall objective of this project was to examine the potential benefits of a flow battery installation at Foote Creek Rim I. The analytic approach was to:

- Identify preferred battery charge and discharge periods based on periods of transmission line congestion and wind variation at the wind farm.
- Assess tariff rate variables on the economics of modeled flow batteries under scenarios with and without transmission line congestion.
- Evaluate the effects of battery capital cost, salvage value, and rebate on battery system economics.
- Analyze the potential economic benefit of capturing spilled, light winds, enabled by the installation of an energy storage system.

[7] On May 18, 2006, FERC issued a notice of proposed rulemaking to update Order 888, the landmark open transmission access order that FERC issued in 1996. Transmission owners/operators are investigating conditional firm products and will likely file those tariffs with FERC. PacifiCorp, since its merger with MidAmerican Energy Holdings, is pursing novel Conditional Firm products, with public stakeholder participation. Three products are being considered. Benefits to firm providers include capacity payments (in addition to energy payments) for successful delivery of pre-determined amounts of power; and high priority dispatch (i.e., reduced chances of curtailment during congestion) throughout designated firm periods.

2 Methods

Excel spreadsheet models were developed to project wind farm power output and economics of an energy storage system under different tariff rates, with and without transmission line congestion. Datasets were used to determine battery charge and discharge cycles and assess battery economics under different conditions.

2.1 Datasets

The datasets used in this project, their sources, conversions, and applications were provided by team participants after non-disclosure agreements were signed.

- *Wind Speed Data.* Wind speed measurements (meters/second, m/s, in 10-minute intervals for the year 2003) were provided by AES SeaWest under a non-disclosure agreement for six meteorological stations and each of the 69 wind turbines at Foote Creek Rim I. This dataset had to be reduced before it could be used in the analysis. An Excel model was used to reduce the 10-minute interval data to hourly averages and compare the wind speeds across the meteorological stations and turbines to prove that the wind speeds aligned. The wind speeds recorded at the six meteorological stations were averaged to create a single set of hourly wind speeds to represent the entire wind farm. This data was used to assess wind speed variation over the year.

- *Turbine Power Generation.* Power generation (watt-hours in 10-minute intervals over the year 2003) was provided by AES SeaWest under a non-disclosure agreement for each of the 69 wind turbines and substation at Foote Creek Rim I. Hourly power generation was calculated by adding six sequential 10-minute intervals. An Excel model was used to calculate power generation from the actual wind speed readings at nine turbines located at discreet segments along the ridge. Wind speed and power generation data were validated. In addition, the power generation output from the substation was validated against the summed generation output of all 69 turbines and found to be within tolerance (see Appendix B). Hourly power generation from the substation was used in the Excel model to project hour-by-hour output from the wind farm.

- *Transmission Line Load.* End-of-hour load data for TOT 4A and 4B were provided by PacifiCorp under a non-disclosure agreement for the year 2003. This data was used to determine the periods of greatest congestion, and hence periods during which non-firm power from Foote Creek Rim I was least likely to be dispatched. Hourly load throughout the year was used to trigger curtailment in the Excel model.

- *VRB-ESS Energy Flow.* One month of energy flow data from the 2-MWh VRB-ESS was provided by PacifiCorp. In Utah, the VRB-ESS was installed at the end of a long 25-kV feeder line strained by significant seasonal demand fluctuations – a very different application from that envisioned in this study. The data from Utah was used in a preliminary assessment to confirm the round-trip efficiency of the system and the fact that the VRB-ESS did not self-discharge while in an idle state.

2.2 Tariff Rates and Rebates

Large wind farms negotiate Power Purchase Agreements with the utilities buying their wind power. PacifiCorp is no longer vertically integrated, and as a result, different business units operate different assets. The entity responsible for the wind farm was unwilling to share the terms of its Power Purchase Agreement. PacifiCorp offers a conservative $0.035/kWh energy charge with no time-of-day or seasonal variation and no capacity charge for small-scale purchase of renewable generation in Wyoming. This investigation required a more aggressive tariff, with seasonal and time-of-day variation to encourage discharge of the wind energy stored in order to maximize revenues. As a result, the analysis examined tariffs used in California with capacity and energy charges and time-of-day factors as a proxy for the Power Purchase Agreement rates.

Tariffs were examined in two ways, as a "proxy" tariff based on an actual tariff, and as a simplified tariff to examine the economics of energy payments alone. The simplified tariff for examination of energy rate effects had one season and two time-of-use (TOU) energy rates – a high weekday rate from noon to 18:00, and a single low rate for all other times. The difference between high and low rates was modeled to vary from $0.05 to $0.15 to examine rate differences during battery charging and discharging required for economic viability in absence of other cash inflows (i.e., capacity payments and rebates).

For all other analysis, a proxy tariff was used that was based on the generator portion of the unbundled demand rates for a Pacific Gas & Electric (PG&E) tariff for medium commercial/industrial facilities (i.e., Schedule E-19). This tariff designates two seasons, and three TOU periods (see Table 1). TOU periods were rounded to whole hours for this project (i.e., 20:30 became 21:00).

Table 1. Seasonal TOU Periods Defined in Selected Tariff

TOU Period	Summer (May-Oct)		Winter (Nov-Apr)		Day of week
	Start	Finish	Start	Finish	
Peak	12:00	18:00			M-F
Part-peak	9:00	12:00	9:00	22:00	M-F
	18:00	22:00			M-F
Off-Peak	22:00	9:00	22:00	9:00	M-F
	0:00	0:00	0:00	0:00	Sa-Su

Two types of payments are provided in this tariff – an energy payment and a demand payment. The demand payment is comparable to a capacity payment in a generator's contract.[8] The energy payment is determined from the amount of power delivery, and the tariff-designated Energy Rate. The capacity payment is determined from the successful delivery of a pre-determined amount of power and the tariff-defined capacity price ($/kW). As shown in Table 2, the proxy energy rates and capacity rates vary by TOU period and season.

Table 2. Seasonal TOU Energy and Capacity Payments in the Proxy Tariff

TOU Period	Energy Rates ($/kWh)		Capacity Price ($/kW)	
	Summer	Winter	Summer	Winter
Peak	0.10334	NA	75	NA
Part-peak	0.07502	0.06613	NA	NA
Off-peak	0.04903	0.0502	NA	NA

Modeling a capacity payment assumes a conditional firm tariff, which would likely be enabled by an energy storage system. Under the proxy tariff, the most lucrative period for selling power (i.e., battery

[8] The PG&E Schedule E-19 demand payment was only $7.78/kW. It was thought that this demand payment is much lower than typical capacity payments, thus we use a capacity payment of $75/kW.

discharge) is during the summer peak period, which has both a capacity payment and the highest energy rate. The best period for battery charging (i.e., reducing sales to the grid) is during the off-peak period, when energy rates are lowest and there is no capacity payment.

One final note regarding tariffs, the capacity payment carries a penalty for non-performance. This penalty varies by utility. The penalty rate used in this study was 1.25 times the capacity rate, which is the same as that used in a recent California Energy Commission model.[9] For the purposes of this study, the penalty is assumed to apply to each hour in which the delivered wind generation did not meet promised targets.

2.3 Excel Model for Storage System Analysis

An Excel-based model was developed for economic analyses of power generation and discharge from an energy storage system. The model incorporates one year of hourly average data of wind speed and power generation data from Foote Creek Rim I, and requires input variables such as power storage system specifications and tariff prices (see Table 3).

Table 3. Energy Storage System Economic Model Input Variables

Storage System Parameters and Costs	Tariff and Other Economic Variables
• Round-trip efficiency losses (%) • Minimum discharge level (%) • Rate of charging and discharging (kW) • Charge and discharge schedules (daily, weekly, and seasonal) • Battery capital costs • Battery Operations & Maintenance (O&M) costs ($/kWh) • Battery salvage value ($/kWh) and annual change in value relative to constant dollars • Expected life (up to 30 years) • Capital depreciation (7, 10, 15, or 20 years)	• TOU and season definitions • Energy rates • Capacity rates and penalty • Minimum power delivery and percent chance of failure to deliver during peak periods • Transmission line load (%) at which curtailment begins, and % curtailed at different loads • Rebate amount and year of provision • Federal and State tax rates (%) • Rate of return

Based on this input, the model projects the quantity of power output to the grid during each hour of the year for the wind farm (with no battery), and for the wind farm with an installed battery (see Table 4). Hourly power output is multiplied by the applicable tariff-defined payments. The difference between these payments with and without a battery is calculated as the battery revenue. Battery costs are then subtracted from this revenue to assess overall economic viability of the battery. Thus the economic analysis in this study assesses the incremental change in cash inflow and outflow due to battery installation and operation. For this study, the project life was defined as 20 years, with 15 years capital depreciation. All costs were developed in collaboration with the battery manufacturer.

When applicable, capacity payments were calculated as monthly capacity payments from the minimum expected power delivery during the peak period, reduced by estimated monthly capacity penalties. For this study, minimum expected deliveries (or commitments) were estimated as the battery designed discharge rate. Hourly generation data and modeled battery discharge were summed to determine when power output during the peak rate period failed to meet the hourly peak rate commitment.

[9] Lamont, A., Improving the Value of Wind Energy Generation Through Back-up Generation and Energy Storage, California Energy Commission, CEC-500-2005-183, April 2004, p. 3.

Table 4. Energy Storage System Economic Model Output and Projection Periods

Output	Projection Period			
	Hourly	Monthly	Annual	Life Cycle*
Battery discharge (kWh)	●	●	●	
Output to grid	●	●	●	
Energy revenue		●	●	●
Probability of capacity penalty (failure to meet commitment)		●		
Capacity revenue (penalties incorporated)		●	●	●
Total revenue due to battery		●	●	●
Battery O&M costs			●	●
Rebate			●	●
Salvage value				●
Taxes *(does not include possible taxes on rebates)*			●	●
Tax reductions for other operations **			●	●
Capital costs				●
Net Present Value (NPV)				●
Rate of Return when NPV = 0				●

* Life cycle cash flows are calculated as present value with the input rate of return.
** Tax deductions for other operations are only applicable when tax deductions for capital depreciation exceed cash inflows.

2.4 Excel Model for Light Wind Capture

The cut-in and cut-out speeds for the Mitsubishi turbines at Foote Creek Rim I were set at 4.8 m/s and 27 m/s, respectively (if temperatures were very cold, the turbines would cut out at lower speeds). This cut-in speed is higher than many other similar turbines due to the high altitude of Foote Creek Rim, and related low air density and wind power. Turbine cut-in speed is often set a little higher than the actual minimum wind speed at which turbine blades are moved and power is generated to reduce the number of times the turbine generator is turned on and off, and associated mechanical stress. Thus, while the Mitsubishi turbine controlling software allows easy re-setting of the cut-in speed, power gains from reducing the cut-in speed are not thought to be significant.[10] In some cases, older turbines may be retrofit to allow lower cut-in wind speed, allowing the capture of currently spilled light winds.

In this section, the model for storage system analysis was modified to evaluate the potential benefits from retrofits to capture some of the currently spilled light winds, recognizing this analysis is not likely to be applicable to the Mitsubishi turbines at Foote Creek Rim I. Power generation from these light winds would not be sent directly to the grid, but could be directed to an energy storage system for conditioning and subsequent sale to the utility. Thus, the light wind capture retrofit is only possible after storage system installation, and could provide an additional benefit of the storage system. As in the model for storage system analysis, the light wind model estimates the incremental costs and cash benefits of the retrofit. While battery size and tariff rates are incorporated in this analysis, they are only used to assess the amount and value of captured light winds.

In contrast to the battery system cost estimates used in the storage system mode (i.e., developed in collaboration with the battery manufacturer), cost estimates for this enhancement are general estimates. It was estimated that the capital costs for implementing this retrofit could be $100,000. O&M costs

[10] Personal communication with Mr. Utomi, Mitsubishi Engineering Manager for Foote Creek Rim I turbine installation, 4/3/07.

associated with the retrofit were estimated as 0.5% of the capital costs per year. Input variables used in the model for light wind capture retrofit are shown in Table 5.

Table 5. Light Wind Model Input Variables

Retrofit Costs and Specifications to Estimate Captured Power	Storage System Costs and Specifications	Tariff and Other Economic Variables
• Retrofit capital costs • Retrofit O&M costs • Air density • Rotor diameter • Power coefficient for light winds • Current turbine cut-in speed • Retrofit turbine cut-in speed • Expected life (up to 10 years) • Capital depreciation (3, 5, or 7 years)	• Round-trip efficiency losses (%) • Minimum discharge level (%) • Rate of charging and discharging (kW) • Charge and discharge schedules (daily, weekly, and seasonal) • Battery O&M costs ($/kWh)	• TOU and season definitions • Energy rates • Capacity rates and penalties • Minimum power delivery and percent chance of failure to deliver during peak periods • Transmission line load (%) at which curtailment begins, and % curtailed at different loads • Federal and State tax rates (%) • Rate of return

The model calculates and compares profits with and without spilled wind capture by calculating hypothetical power generation for wind speed less than the current cut-in speed (4.8 m/s). The actual power generation data included hourly generation during many hours with average wind speeds that were less than the turbine cut-in speed. Because wind power increases to the cube of wind speed, small increases in wind speed cause a far greater change in wind power. Power generation data were adjusted as follows to create comparable datasets:

- No Spilled Wind Capture: Power generation data with the current cut-in speed was altered by setting all measured generation to zero during hours with an average wind speed < 4.8 m/s.
- Spilled Wind Capture: Power generation during hours with an average wind speed < 4.8 m/s but more than the retrofit cut-in was calculated based on the standard equation for wind power (i.e., the product of half the air density, wind speed cubed, and rotor area) multiplied by the input turbine and site-specific power coefficient for light winds.

All power generation from light winds was modeled to be sent to the battery (when it was not fully charged) regardless of whether the battery was scheduled to be charging, discharging, or idling. In this study, the power coefficient for light winds was input as the power coefficient for the lowest wind speed measured in the turbine manufacturer's power curve (i.e., 13%). The economic benefits of the retrofit were assessed based on the difference in profit with and without the retrofit, using an expected life of 10 years, and capital depreciation over 5 years.

This method may overestimate the benefits of capturing light winds. First, setting all base-case generation to zero when the hourly average wind speed is less than the cut-in speed may overestimate the time during which winds light winds may be caught with the retrofit. Second, setting the power coefficient to be the same as for the lowest non-zero measurement in the turbine's current power curve is optimistic. At lower wind speeds, the power coefficient typically decreases with wind speed.

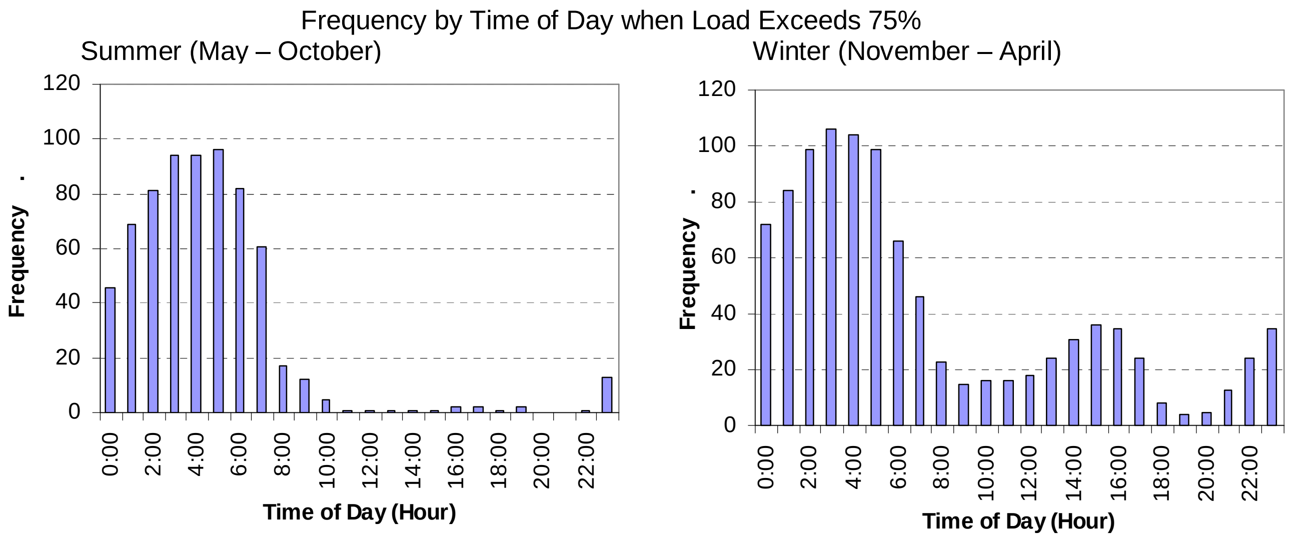
3 Time of Day Patterns in Data

The observed patterns of power generation, associated wind speed variation, transmission line congestion, and high-demand periods in tariffs were the primary factors considered in determining storage system cycling schedules.

3.1 Transmission Line Congestion

In this study, wind farm curtailment was modeled to begin when the load on TOT4 reached 75% based on hourly averages. This provides a relatively high rate of curtailment to facilitate assessment of curtailment effects.[11] As seen in Figure 1, congestion along PacifiCorp TOT4 primarily occurred in the early morning hours. According to PacifiCorp, these constraints were due to scheduled power flows to and from the Northeastern portion of the state in anticipation of major power plant outages for maintenance, and thus are not associated with periods of peak demand in the Western states. Hence, power transfer from the wind farm to the grid was most likely to be curtailed during early morning hours. This implies that the battery should charge during the early morning and discharge at other times.

Figure 1. TOT4 Transmission Congestion Profile



Another way to examine transmission line congestion is presented in Table 6 – counting the number of hours during which transmission line load exceeded 75% and calculating the percentage of hours in each tariff period that transmission was congested. Only 15% of the hours in the Summer witnessed transmission line congestion whereas 23% of the Winter hours were congested. For Foote Creek Rim I, the hours within a day that were most likely to be subject to curtailment due to transmission line congestion occurred during lowest tariff rate period. Transmission line congestion does not translate into total curtailment of the wind farm. Rather, a small portion of the generation – 10% -- was modeled to be curtailed whenever the transmission line load exceeded 75%, increasing to 50% curtailed when the transmission line load reached 100%. This approach was developed from expert opinion.

[11] Actual curtailment of the wind farm due to transmission line congestion in 2003 is not provided in the available datasets. However, curtailment occurred substantially less frequently than indicated by the curtailment scenario used in this analysis (i.e., beginning at 75% transmission line load).

Table 6. Transmission Line Congestion by Season and Tariff Period

Season	Rate Period	Total Hours	Congested Hours	% Time Congested
SUMMER	Peak	789	8	1%
	Part-Peak	920	21	2%
	Off-Peak	2,707	654	24%
	Total	**4,416**	**683**	**15%**
WINTER	Peak	0	0	0%
	Part-Peak	1,681	245	15%
	Off-Peak	2,663	758	28%
	Total	**4,344**	**1,003**	**23%**

3.2 Wind Speed and Power Generation

The annual average wind speed at Foote Creek Rim I in 2003 was 10.65 m/s, and average generation was 14.7 MW (see Figure 2). The 20th percentile of wind speed indicates that 20% of the time, wind speed was 4.48 m/s or less. The turbines did not generate power when wind speed falls below 4.8 m/s. This suggests that wind speeds at Foote Creek Rim I were very low during one of every five hours.

Monthly average wind speed and power generation varied at Foote Creek Rim I throughout 2003 (see Figure 3). Average monthly wind speed during the summer months (May through October) was 8.6 m/s, with an average power generation of 10.1 MW. During the winter months (November through April), average monthly wind speed was 12.7 m/s and generation 19.5 MW. Better turbine performance was achieved in the winter due to higher wind speeds, fewer periods of light winds, and less frequent planned maintenance periods.

Figure 2. Power Generation and Wind Speed Percentiles

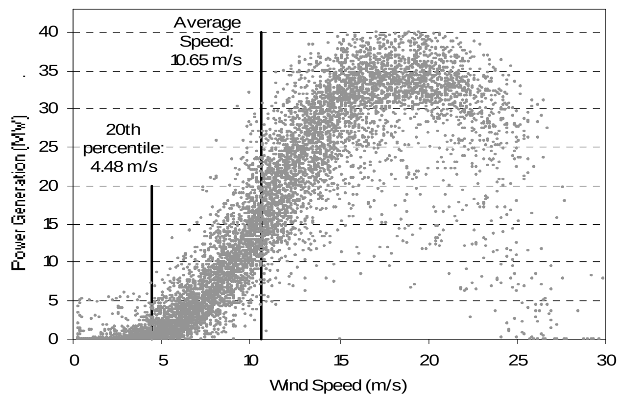
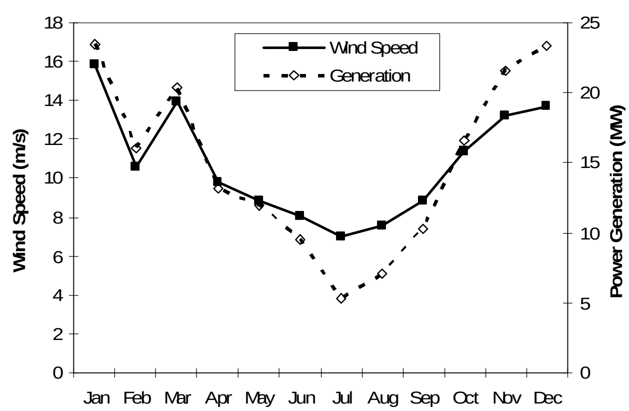
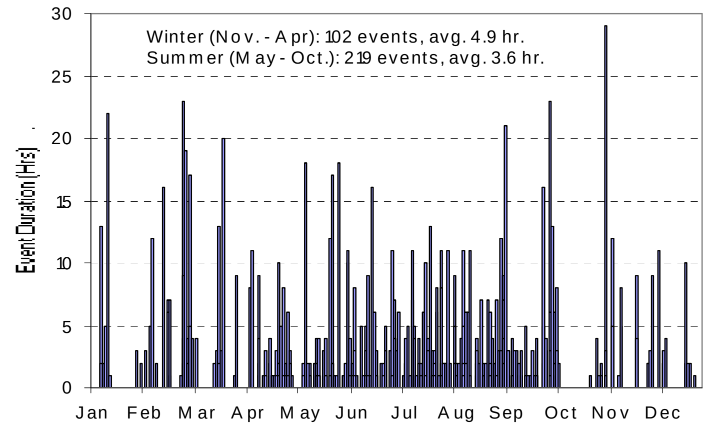


Figure 3. Monthly Average Wind Speed and Power Generation



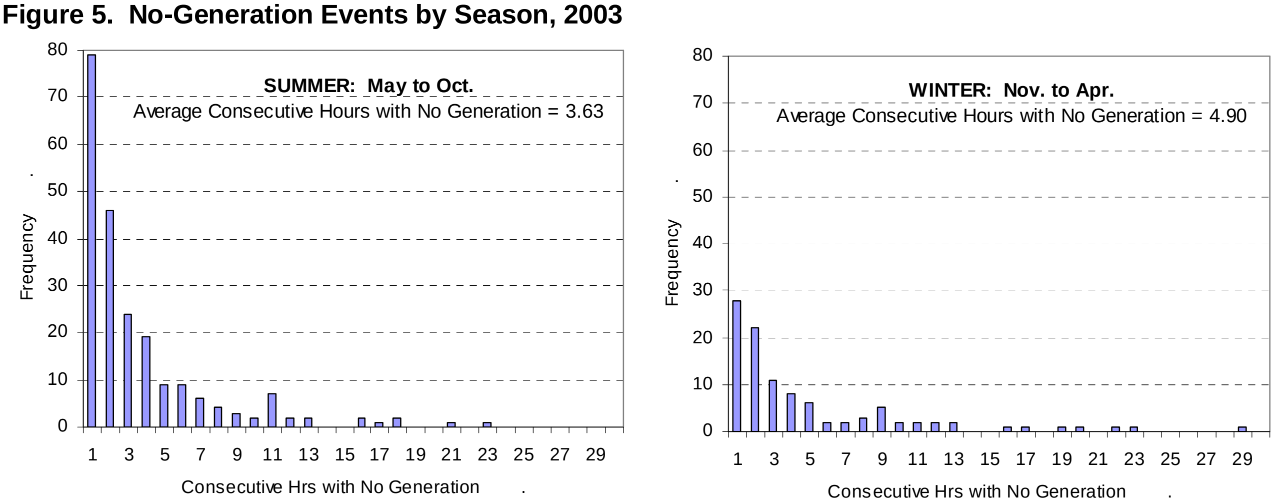
In the summer there were more frequent periods of light winds (speeds below 4.8 m/s). Figure 4 shows the number of consecutive hours without power generation for each no-generation event in 2003. The longest event was 29 hours in early November – substantially longer than the discharge capability of the energy storage system modeled in this study. The density of the relatively short bars during the summer months in Figure 4 indicates that no-generation events were both shorter and more common in the summer. Overall, during winter of 2003, there was no power generation for 11% of the total hours, and the average no-generation event lasted 4.9 hours. In contrast, there was no power generation for 17% of the total hours during the summer, and the average no-generation event lasted only 3.6 hours.

Figure 4. Seasonality and Duration of No-Generation Events



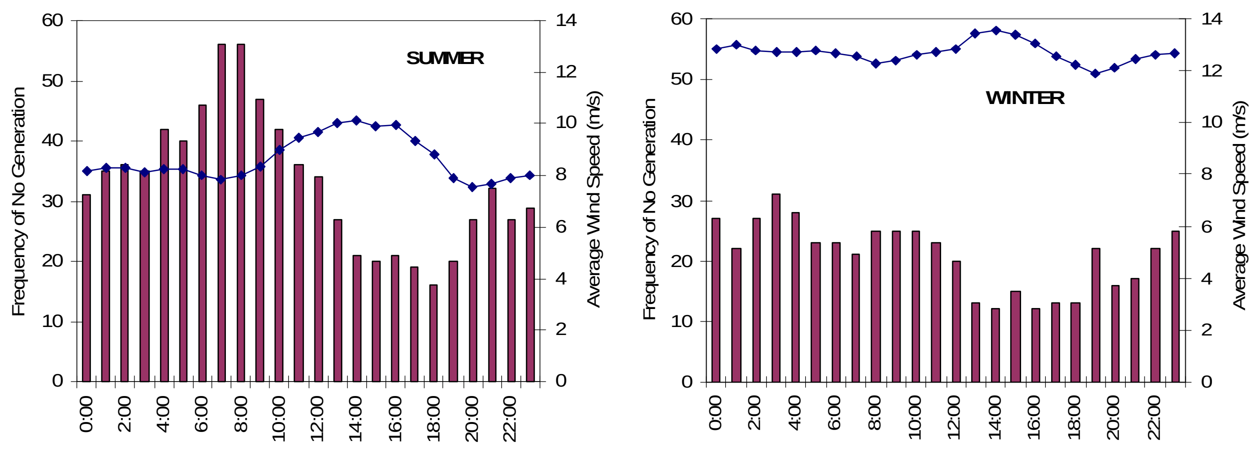
Hypothetically, if battery discharge is scheduled for six hours a day, the battery would charge for at least eight hours a day for full recharge (compensating for round-trip efficiency losses). This suggests that no-generation events that last more than ten hours have the potential to prevent full battery recharge. Figure 5 shows the frequency of no-generation events in the summer and winter by the number of consecutive hours with no power generation. In the summer, there were 18 no-generation events that exceeded 10 hours in duration, while in the winter, there were only 13 no-generation events that exceeded 10 hours. As a result, it is not surprising that the battery was able to fully recharge on more days in the winter than in the summer.

Figure 5. No-Generation Events by Season, 2003



There was an inverse correlation between average hourly wind speed and the frequency of the no-generation events by TOU and season (see Figure 6). The most common time for no-generation events was between 6AM and 10AM in the summer, and between 2AM and 4AM in the winter. In both seasons, average hourly wind speeds were greatest in the afternoon, and no-generation events were least common in the mid-to-late afternoon.

Figure 6. Wind Speed and No-Generation Events by TOU and Season, 2003



The patterns of wind speed and corresponding power generation during 2003 suggest that the battery could be charged more rapidly in the afternoon, when wind speeds were greatest. Particularly in the summer, if battery charging is set during the lowest rate periods (i.e., morning hours), it would take longer, on average, to fully recharge the battery, due to lighter winds.

3.3 Battery Cycling, Transmission Congestion, and Tariffs

In the model, the proxy tariff triggered battery cycling, charges during low rate periods and discharges during peak periods. For a wind farm with a non-firm tariff (i.e., with no firm delivery periods), battery recharge is preferred during periods with greatest congestion because curtailment would not affect charging. At Foote Creek Rim I, peak congestion periods coincided with the lowest rate periods in the proxy tariff. As a result, there was no conflict in the optimal battery charge/discharge schedule based on the combined consideration of congestion patterns and tariff rate periods.

Charging the battery during periods with the greatest wind speed and lowest frequency of no-generation events can increase the probability of a fully charged battery at the onset of a "firm" period. In the case of a conditional firm tariff with firm delivery hours set based on daily wind speed patterns at Foote Creek Rim, the battery would charge during the afternoon, and discharge during other periods, despite greater transmission line congestion. Congestion patterns can be given less consideration under a conditional firm tariff because during the designated "firm" period, the power provider is among the mostly likely to be dispatched, and the least likely to be curtailed.

For the modeled scenarios in this study, battery cycling was scheduled to maximize the energy and capacity charges that would accumulate from the proxy tariff rates and schedule. For economic viability, battery discharge periods require higher payments than battery charge periods. Payments during the discharge period should be sufficiently high to compensate for round-trip efficiency losses during battery cycling. If the battery discharges and charges during the same rate period, there will be a loss of revenue due to round-trip efficiency limitations. As a result, under the proxy tariff, there would be no benefit from battery discharge during weekends with continuously low rates.

With respect to weekdays, the energy rate at which the stored energy is sold needs to be at least 30% greater than the energy rate at which the battery is charged to compensate for battery cycling losses, plus the O&M costs (i.e., $0.008/kWh discharge). Using this rule of thumb, under the proxy tariff, energy stored during an off-peak period can be sold either during the part-peak or peak rate periods, but charging should not occur during the part-peak or peak rate periods except during curtailment. Charging the battery with curtailed power is essentially the same as charging at a payment rate equivalent to $0.

Depending on wind speeds, the battery charge period may need to be substantially greater than the discharge period. In the model, the time needed for full battery recharge varied from 8 hours to more than 24 hours. The battery charge and discharge schedule for each season are inputs to the model, and there are no penalties for extended charge periods. Thus, the battery charge period was set to coincide with all off-peak hours with the exception of one idle hour during the early morning on weekends. During summer weekdays, the battery was idle during the part-peak period, and discharged during the peak period (i.e., weekdays, noon to 18:00). In scenarios with battery operation during the winter, the same discharge period was applied, as there were no peak hours during the winter (see Tables 1 and 2 on page 5). A battery recharge with curtailed energy was permitted whenever the battery was not fully charged.

4 Flow Battery Assessment

The battery economic model was exercised under a variety of conditions to assess the effects of key variables on revenue. Some findings are unique, such as a choice to not operate the battery during seasons when tariffs are restrictive yet still achieve considerable annual income. Shortcomings of tariffs in place become evident from the discussion that follows.

4.1 Battery Discharge and Revenue

With the inputs described in the study, the model yielded unique discharge and revenue output for the 12-MWh flow battery proposed for Foote Creek Rim I (see Figure 7). Without transmission constraints, both summer and winter six-hour discharge matched the summer six-hour peak period of the proxy tariff, and the battery was charged during the off-peak rate period. While battery discharge varied from month to month, this variation did not strongly correlate with season in the model. Battery revenue, however, varied greatly with season, with positive revenue in the summer months, and negative revenue (i.e., losses) in the winter months. The negative winter revenue was a result of the small difference in the winter energy rate during the battery charge and discharge periods (i.e., $0.016), compared to a $0.054 difference during the summer. Note that the winter month with the lowest battery discharge (February) was the winter month with the smallest loss. This suggests that under conditions of no transmission constraints or other economic incentives, the battery should not discharge during the winter.

Figure 7. Discharge and Revenue Modeled for a 12-MWh Battery

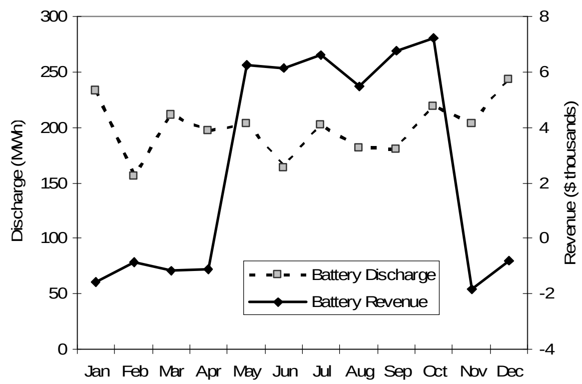
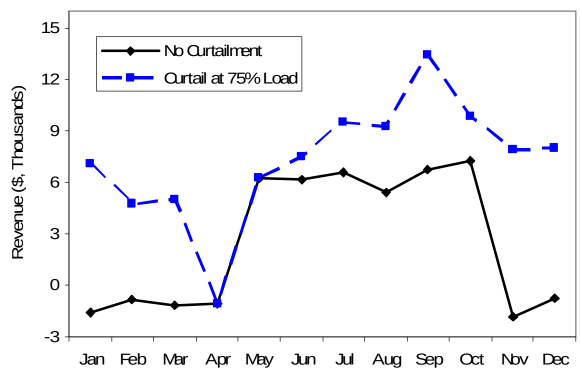


Figure 8. Modeled Revenue With and Without Curtailment for a 12-MWh Battery



The model revenue curve for the battery was substantially improved under conditions of transmission line congestion that resulted in wind farm curtailment (see Figure 8). Note that in months with little to no curtailment (April and May, evident in Figure 8), curtailment scenario revenue is identical to the No-Curtailment revenue. The increase in revenue due to curtailment is generally greater during winter months because average wind speed is greater and more curtailed energy can be sent to the battery. In this scenario (i.e., based on TOT4 load data with 10% curtailment beginning at 75% load and increasing linearly to 50% curtailment at 100% load), annual energy revenue due to the battery increased by a factor of 2.5. Revenue increases due to curtailment are particularly substantial because the effective energy rate of curtailed energy is $0. Thus, the rate differences between the periods of battery charge and discharge during the peak rate period are greater with curtailment than without curtailment (see Section 4.4 for further discussion of energy rate differentials).

4.2 Cash Inflow and Outflow

To assess the economic viability of a storage system, revenue and other cash inflow should be considered in relation to cash outflow over the life of the project. Cash outflow includes the initial cost of the battery, O&M costs, and taxes. The battery manufacturer estimated annual O&M costs to be $0.008/kWh. In some of the modeled scenarios, cash inflows were less than tax deductions for capital costs over a 15-year depreciation schedule.[12] Thus, it was assumed that the modeled storage system would be part of a larger business operation with substantial profit and taxes, from which the battery depreciation could be deducted. With this assumption, battery depreciation deductions applied to other operations yielded reductions, or savings in taxes paid on these operations. Thus, profit would be calculated as the sum of battery revenue, rebates, and reductions in taxes paid on other operations when applicable, minus the sum of battery capital costs, O&M costs, and taxes paid on battery operations.

From an economic standpoint, the value of a payment (i.e., profit) today is greater than the value of the same (nominal) payment in the future. This is due to the time value of money, which is based on the ability to invest and earn interest on a payment received today, in addition to the risk that the future payment may not occur. The most common method for determining the present value of future cash flows adjusted for the time value of money is based on equations for the calculation of compound interest. When calculating present value of a future payment, the interest rate applied in these equations becomes the discount rate. The discount rate is the same as the rate of return on investment, also referred to as the internal rate of return (IRR).

The present value of cash inflow and outflow for each year of the project can be calculated and summed over the project life to assess overall economic viability. For assessments over the project life, a final cash inflow to consider is battery salvage value. For the energy storage system modeled in this study, the current salvage value of the battery vanadium is estimated to be $150/kWh. Over the past decade, vanadium spot market prices have increased on average, about 6% per year. For this analysis, we assumed that salvage values would increase on average, 3% per year over a 20-year project life. Using these assumptions, the 20-year present value of salvage for the battery modeled would be $483,240, assuming a 10% rate of return.

Figure 9 presents life cycle (20-year) present values of cash inflow and outflow for the 12-MWh battery with no transmission line constraints. A 10% rate of return was applied in this analysis. Scenarios A, B, and C in Figure 9 represent increasing sources of cash inflow:

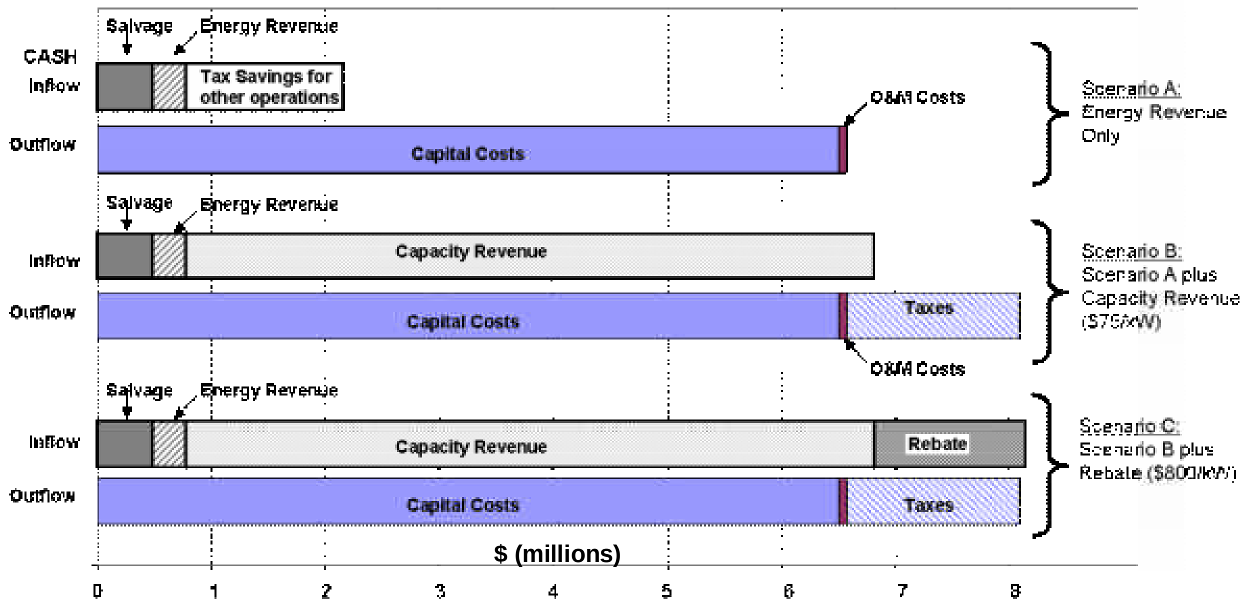
- Energy payments only
- Energy payments and a capacity payment
- Energy payments with a capacity payment and a rebate

The battery was modeled to run only during the summer months, when the energy payment was greatest, and when the successful negotiation of a capacity payment was most likely. (As seen by the winter losses in Figure 7, winter operation of the battery was not economically viable under the PG&E tariff -- this extends to scenarios with a capacity payment that is only available during the summer.) The modeled capacity payment was $75/kW per summer month. For capacity payment calculations, the power delivery commitment during the six-hour peak summer rate period was 2 MW per hour with capacity penalties of 1.25 times the payment goal when the battery was unable to achieve this delivery. The rebate modeled

[12] Based on MARCS 15-year depreciation rates using the half-year convention for bringing equipment into service (i.e., the depreciation tables used by the IRS.)

was $800 per kW capacity paid once, at the end of the second year of operation. This rebate was within the range of the rebates anticipated in California. It was assumed that no taxes would be paid on the rebate, and that the rebate would be applicable with battery operation limited to the summer.

Figure 9. Cash Inflow and Outflow for a 12-MWh Battery Under Three Revenue Scenarios



Note: 20-year present value, 10% IRR.

Capital costs, O&M costs, salvage value, and energy payments shown in Figure 9 are the same for all scenarios. When life cycle cash inflow equals or exceeds cash outflow, the battery operation is economically viable with a 10% rate of return. While energy payments may be greater under other tariffs, additional forms of revenue are needed for a system with capital costs such as those of flow batteries. Depending on the required rate of return for the project, additional cash inflow in the form of a rebate, or outflow reduction in the form of a subsidy might be needed for economic viability.

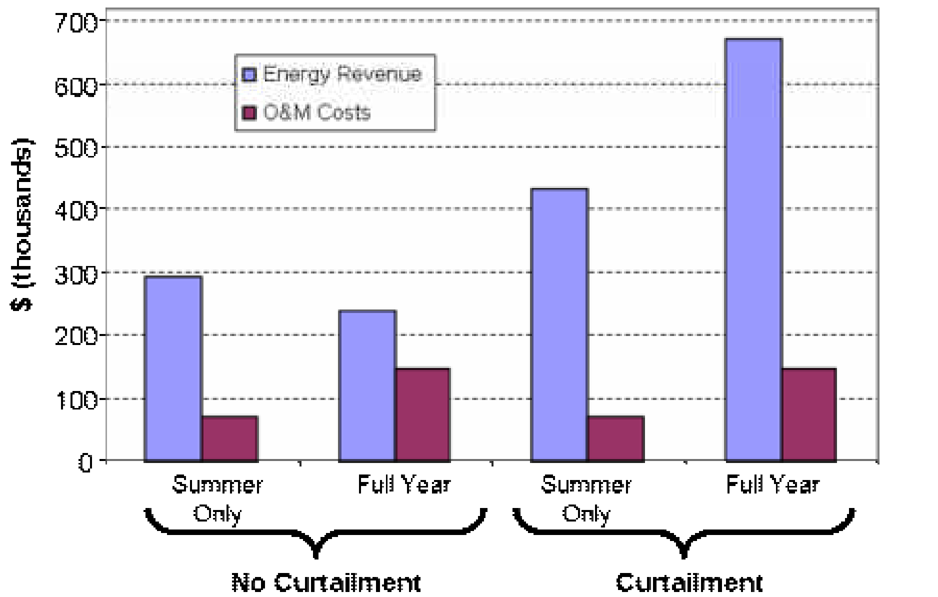
Overall, the economical feasibility of the modeled battery required greater cash inflows than could be obtained from energy payments alone. A combination of favorable capacity payments and rebates or subsidies might enable economic viability.

4.3 Effects of Curtailment

Under the transmission congestion conditions modeled, curtailment does not affect capacity payments. In this analysis, capacity payments are only affected by battery discharge and wind power generation during the peak summer period. Summer curtailment occurs during the off-peak period, when the battery is charging. During the charging period, power is preferentially directed to the battery up to the maximum charging rate, thus curtailment during charge does not affect battery cycling. (It should be noted that curtailment may affect capacity payments at other sites served by transmission lines that have congestion during the peak periods.) Likewise, a rebate would not be affected by the curtailment modeled in this analysis.

Due to the transmission load patterns in Wyoming, the primary cash flow affected by curtailment in this model was energy payments. The primary cash flows affected by summer-only versus full-year battery operation are energy payments and battery O&M and a small effect on taxes. Figure 10 shows the 20-year present value of energy payments and O&M costs under conditions of full-year and summer-only operation, with and without curtailment.

Figure 10. Energy Revenue and O&M Costs by Operation and Curtailment



Under conditions of no transmission constraints, revenue was greater and O&M costs were least when the battery was modeled to operate only during the summer months. In contrast, under the curtailment scenario, revenue was greater with full-year battery operation. While O&M costs also increased with full-year operation, this increase was less than the increase in energy revenue.

Overall, transmission line congestion increases energy revenue when it occurs primarily during off-peak periods. Furthermore, basic operational decisions, such as which months to operate the battery, can be substantially affected by the extent of wind farm curtailment.

4.4 Battery Size and Energy Rate Differentials

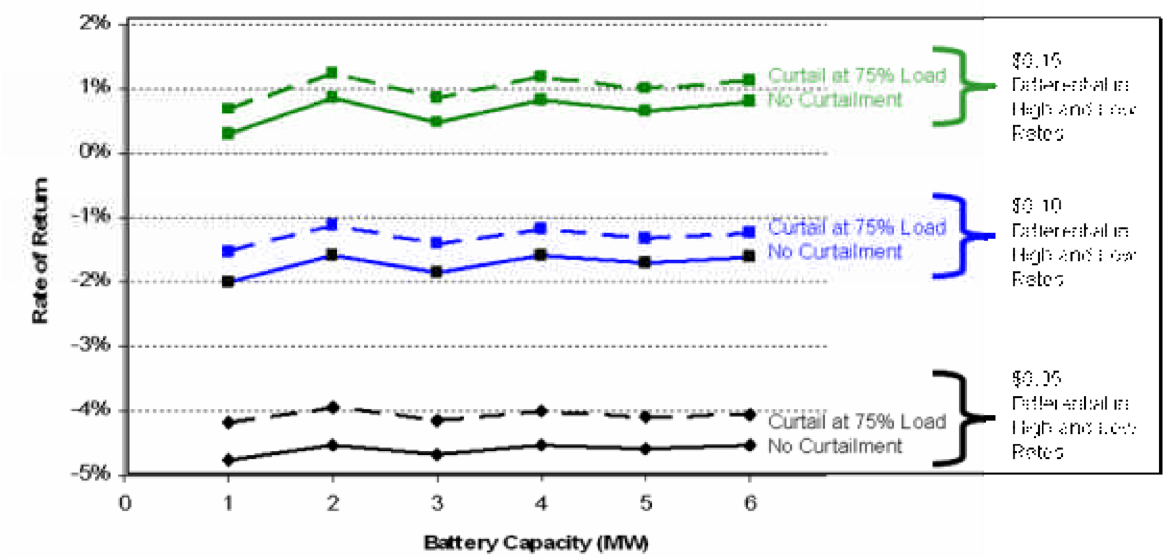
The sum of the present value of cash outflow and inflow is referred to as the net present value (NPV). An NPV equal to zero (0) or a positive number suggests cash inflow equal or exceed outflows, thereby indicating the project is economically viable under the rate of return applied. An acceptable rate of return varies with the interest rates of loans required for capital purchases, and on the investor's requirements for return on their investment.

Recognizing that the energy rates in the proxy tariff are not sufficient for economic viability, a simplified analysis of the effects of energy rate differences between high and low rates (i.e., corresponding to battery discharge and charge periods) was conducted. This analysis used a single 6-hour high rate period (weekdays, noon to 18:00) and 18-hour low rate period with no seasonal differences. Energy rate differentials of $0.05, $0.10, and $0.15 were modeled for a series of batteries designed for 6-hour discharge with capacity ranging from 1 to 6 MW, with resulting energy ratings ranging from 6 MWh to

36 MWh. The NPV was set to 0 by changing the rate of return. The rate of return can then be compared to a company's or investor's requirement.

As seen in Figure 11, neither $0.05 nor $0.10 differentials between low rate and high rate periods yielded a positive rate of return based on revenue solely from energy payments. Regardless of the rate differential, the rates of return in Figure 11 increase under the scenario with wind farm curtailment (i.e., beginning when TOT4 load reaches 75%). A $0.15 differential between energy rates during battery charge and discharge periods provides a positive rate of return for all battery sizes modeled.

Figure 11. Effect of Energy Rate Differential on Rate of Return



Of the battery sizes shown in Figure 11, the 2-MW battery yielded a slightly higher rate of return (hence a 12-MWh battery with 2-MW capacity and a 6-hour discharge period was modeled in Figures 7 though 11). The benefits of the 2-MW battery are easiest to see in the $0.15 differential curves, when the 2-MW battery has a 0.85% rate of return with no curtailment, and a 1.25% rate of return with curtailment. In contrast, the next highest rates of return are for the 4-MW battery, which are 0.81% and 1.01% under no curtailment and curtailment scenarios, respectively. It should be noted that for most investors, a rate of return less than 5% is not likely to be viewed favorably. Thus, the analysis shown in Figure 11 suggests that capacity payments, and/or rebates will be needed for economic viability of the modeled battery system, regardless of battery size.

5 Capture of Light Winds

One of the premises of this study was that the installation of a flow battery could capture and condition spilled winds (below the turbine cut-in speed) for an additional source of battery recharge. It is not thought that the ability to capture light winds can be further enhanced in the installed turbines at Foote Creek Rim. However, there may be some wind power generators that could be improved to capture and generate electricity from light winds. This analysis provides an initial assessment of the potential value of improved capture of light winds.

5.1 Output to Grid and Revenue

Under the modeled enhancements to capture spilled, light winds was assessed with a 12-MWh battery under the proxy tariff. For this analysis, the new cut-in wind speed was 2.5 m/s, and a 13% power coefficient used to calculate power generation from wind speed between 2.5 and 4.8 m/s (the original cut-in speed).

Figure 12 shows monthly increases in power output to the grid and associated energy revenue due to the capture of spilled winds. Compared to power output to the grid, energy revenue is proportionately greater in the summer, when energy rates are greater. Both curves in Figure 12 are roughly the inverse of the monthly average wind speed curve shown in Figure 3 (in Section 3.2).

Figure 12. Energy Revenue and Output to Grid Increases from Spilled Wind

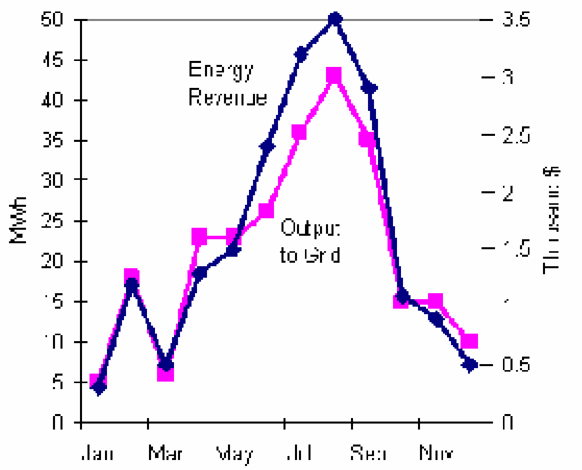
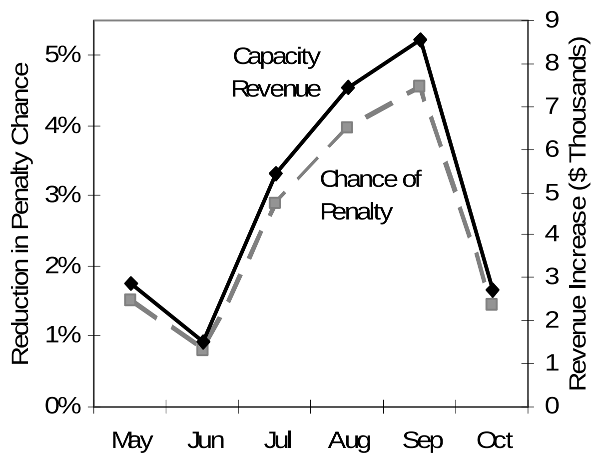


Figure 13. Capacity Revenue Increase and Fewer Penalties from Spilled Wind

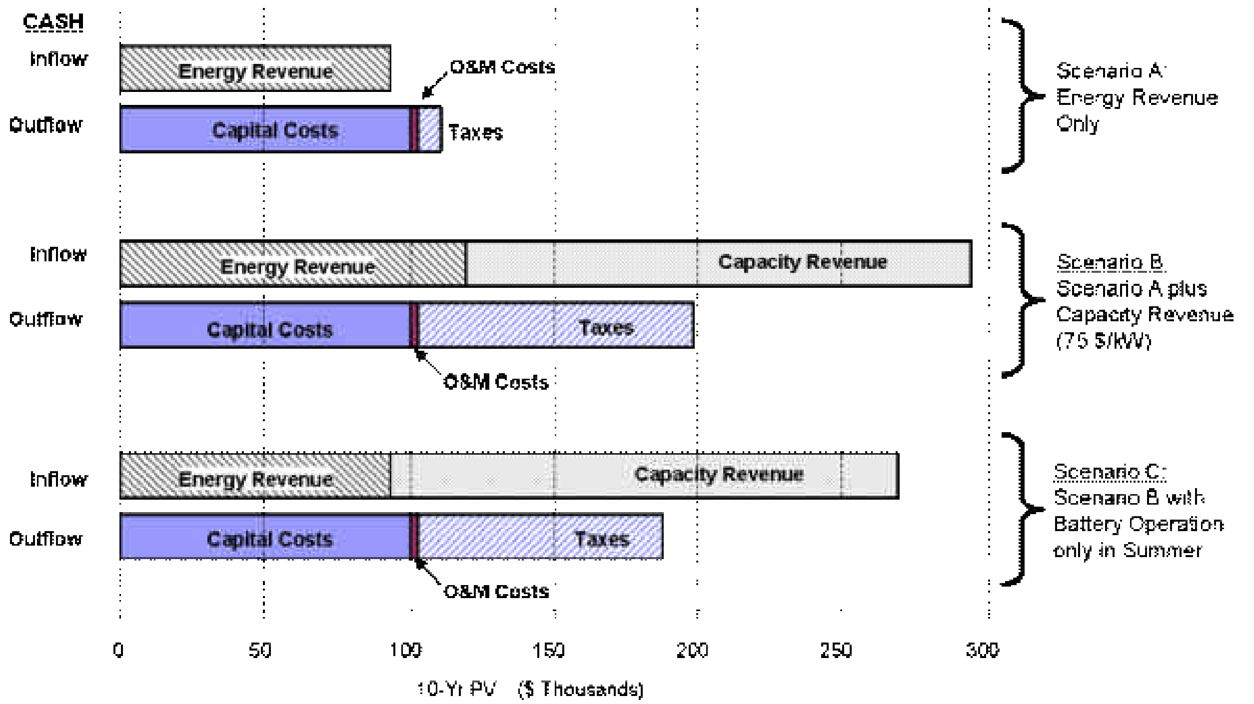


As shown in Figure 13, capacity revenue (only available during summer months) is also increased by the capture of spilled, light winds. The increase in capacity revenue is due to a decrease in capacity penalties as a result of a more fully charged battery, and the resulting decreased chance of failing to meet delivery commitments during the peak period. Although this reduction in the chance of penalties is only a few percent and applies to only one season, it causes greater capacity revenue increases than seen in energy revenues throughout the full year. Reduced chances of failing to meet peak delivery commitments may also improve the ability to successfully negotiate a conditional firm tariff.

5.2 Cash Inflow and Outflow Comparisons

Life cycle (10-year present values) cash inflow and outflow for the light wind capture enhancement to the model are displayed in Figure 14. A 10% rate of return is applied for this analysis. The scenarios have different cash inflows, with Scenario A having only energy revenue (using the proxy tariff), and Scenario B having energy revenue in addition to a $75/kW/summer month capacity payment. Scenario C is the same as Scenario B, except the battery (and hence the light wind capture) is only operated during the summer months, when the capacity payment is available. While it is beneficial from the standpoint of energy revenue to capture light winds throughout the year, the analysis of battery economics suggests it may be preferable to operate the battery during periods when a capacity payment is available (particularly when curtailment is minimal).

Figure 14. Cash Inflow and Outflow for Spilled Wind Capture Under Three Revenue Scenarios



Note: 12-MWh battery, 10-year present value, 10% IRR.

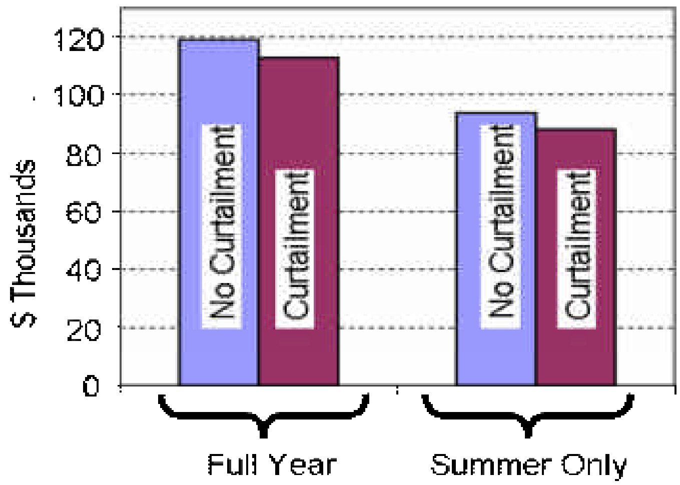
The greater cash inflow compared to outflow for Scenarios B and C suggest potential economic viability of light wind capture when there is a capacity payment and associated penalties for not meeting commitments. In contrast, greater cash outflows than inflows in Scenario A suggest that the spilled, light wind capture is not economically viable when the revenue is only from the energy payments available under the proxy tariff.

5.3 Effects of Curtailment

The transmission line congestion and associated curtailment modeled in the study did not affect capacity payments due to the capture of light winds (i.e., curtailment does not change the chances of penalties). Likewise, modeled curtailment does not affect retrofit capital costs or O&M costs (which were estimated based solely on capital costs). However, life cycle (10-year present value) energy revenue due to the capture of spilled, light winds is slightly reduced by curtailment, as shown in Figure 15. There is also a small effect on taxes, not shown. The negative effect of curtailment on light wind capture economics is a result of the reduced availability of storage capacity for power generation from light winds. In other words, light wind power competes with curtailed power for storage capacity.

Figure 15 shows the change in energy revenue with and without curtailment for both full-year battery operation, and summer-only operation. The reductions due to curtailment were proportionately quite similar (i.e., curtailment caused a 6% energy revenue reduction in the summer, and a 5% reduction over the full year).

Figure 15. Effect on Curtailment on Spilled Wind Energy Revenue



Note: 10-year present value.

6 Conclusions

This study has found that a large multi-MWh energy storage system could provide Foote Creek Rim I wind farm with storage of power generated during periods of transmission congestion for later sale. Such an energy storage system could also increase the reliability of wind generation during periods of peak demand in other markets, thereby enabling the wind farm to seek a more beneficial tariff, such as the conditional firm tariff.

Under the scenarios examined in this study, with key input parameters including flow battery capital costs and battery efficiency, key findings include:

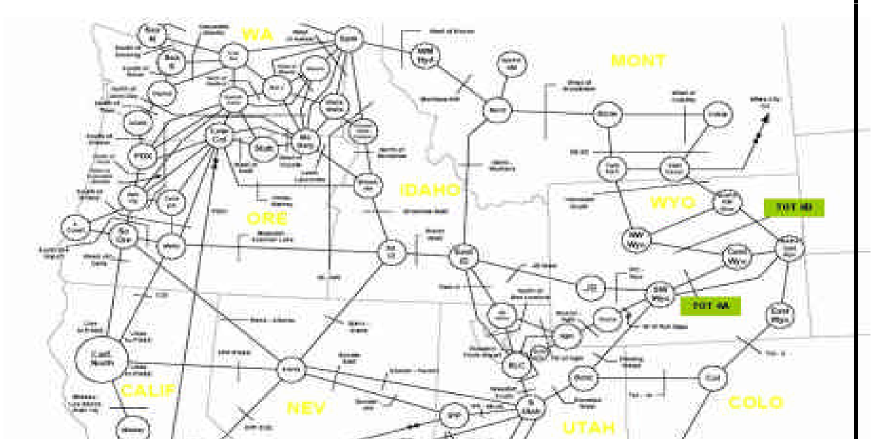
- Energy payments alone may be sufficient to provide a positive return on flow battery investment if the difference between charge and discharge energy rates exceeds $0.15.
- Capacity payments are needed when there are no substantial subsidies and the energy rate differential between battery charging and discharging is less than $0.15 (which is usually the case).
- The absence of capacity payments during a portion of the year may make it financially preferable to not operate the storage system during these seasons.
- The ability to meet power delivery commitments during specified periods is substantially increased by an energy storage system, which may facilitate successful negotiation of a conditional firm tariff with capacity payments.
- Financial viability of an energy storage system may be augmented by factors such as tax incentives, rebates and other subsidies, and high salvage values.
- Capture of spilled light winds can increase battery state of charge and resulting revenue from discharges to allow an acceptable return on a modest (i.e., $100,000) investment to retrofit the wind farm.
- By increasing battery state of charge, the capture of spilled light winds limits the ability of the battery to store curtailed wind generation during transmission congestion periods.
- Under transmission line congestion scenarios that result in curtailment, the ability to store energy for later sale can significantly increase revenue.
- Curtailment has the potential to make it financially preferable to operate an energy storage system when it would otherwise be uneconomical.

Appendix A. Transmission Line Constraints

The Northwest transmission grid is used in ways that weren't envisioned when it was built. Generation and transmission patterns have changed dramatically and the system is showing considerable stress. A major consequence is the growing number of times when the system is congested and operating outside of its operating transfer capability (the industry standard for reliability). Demand on portions of the Northwest grid is particularly high in the summer when large amounts of power are moving into California. The Western Electricity Coordinating Council (WECC) assesses penalties on transmission owners whenever the operating transfer capability is exceeded longer than 20 or 30 minutes.

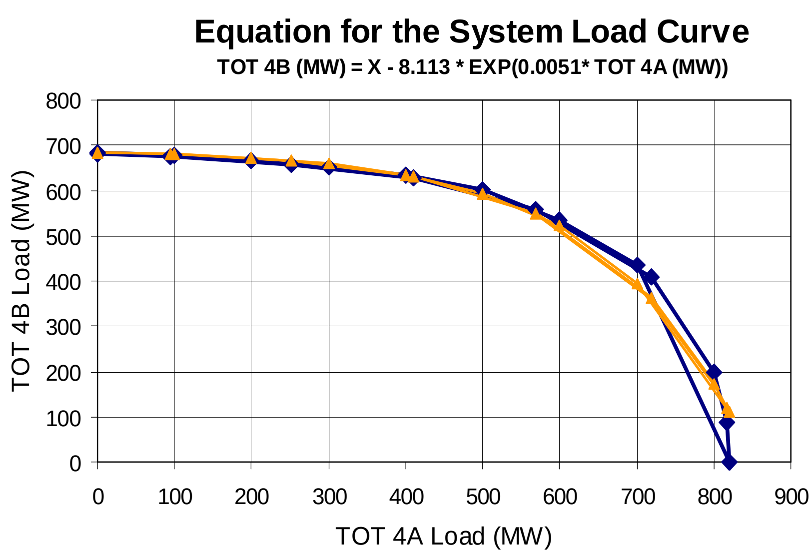
Electricity is transmitted in Wyoming primarily from the Northeast to the Southwest along TOT 4A. A smaller capacity transmission path in the opposite direction is known at TOT 4B. TOT 4A and 4B are not as significantly constrained as the lines they continue on, e.g., Jim Bridger West, which is THE most heavily utilized transmission path in the West (see Figure A-1).

Figure A-1. Transmission Paths Impacting the Northwest



Source: PacifiCorp, Conditional Firm Public Stakeholder Meeting, Oct. 23, 2006, http://www.pacificorp.com/File/File69023.ppt

Figure A-2. Calculating TOT4 Transmission Line Loads



The system load curve for TOT4 was calculated from hourly load data for TOT4A and TOT4B and a WECC report provided by PacifiCorp (see Figure A-2).

This equation enabled an examination of the daily system load on TOT4 during 2003. Two weeks are highlighted in Figures A-3 and A-4: July 25-August 1 and December 14-21. The periods of transmission congestion are easily visible.

Figure A-3. TOT4 Daily System Load – Week in July 2003

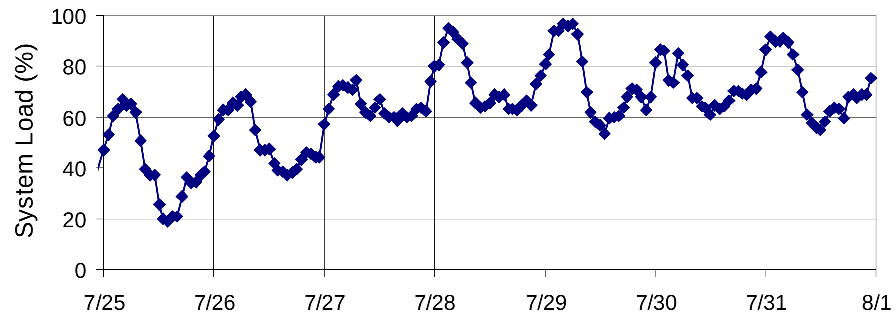
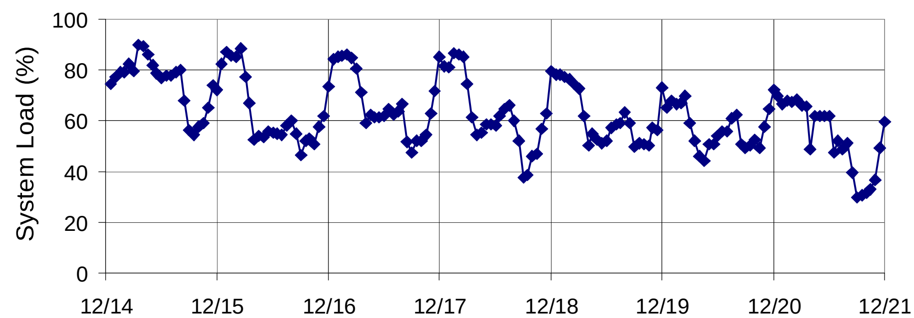
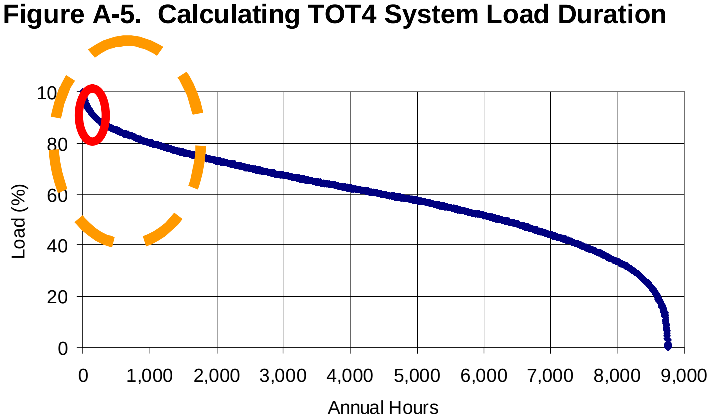


Figure A-4. TOT4 Daily System Load – Week in December 2003



In 2003, there were 187 hours spread over 47 days in which load duration exceeded 90% (RED oval) and 1,686 hours spread over 246 days in which load duration exceeded 75% (ORANGE dashed oval).

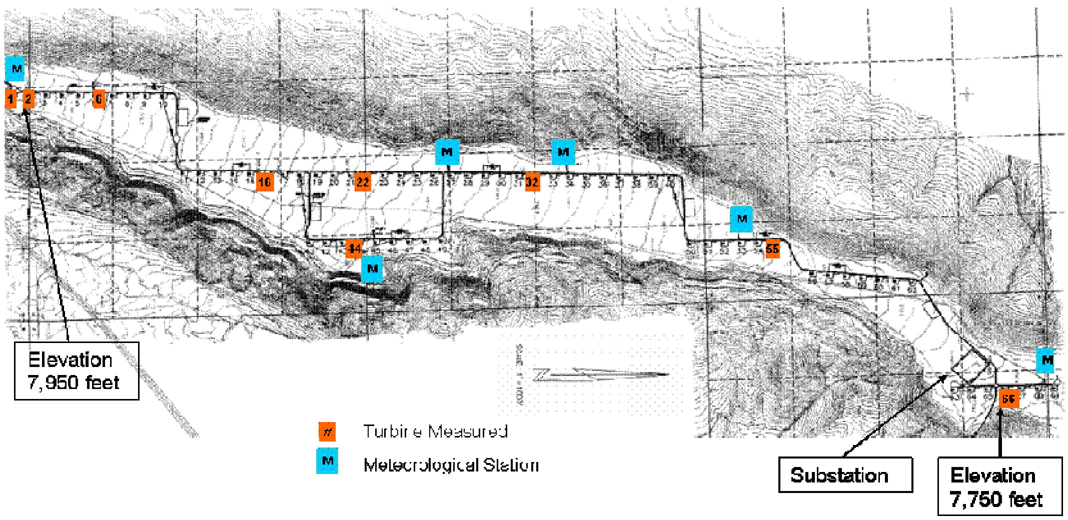
Figure A-5. Calculating TOT4 System Load Duration



Appendix B. Wind Speed and Power Generation

Foote Creek Rim I runs almost three miles atop a ridge with elevation varying from 7,950 feet down to 7,750 feet (see Figure B-1). SAIC built and tested Excel models to validate wind speed measurements across the 69 wind turbines and six meteorological stations and wind generation output from actual wind speeds and turbine operating algorithms. Significant seasonal variations were found, but wind speed measurements across the 69 turbines and six meteorological stations were found to be sufficiently similar to permit use of wind generation at the substation as the input into a model (see Figure B-2).

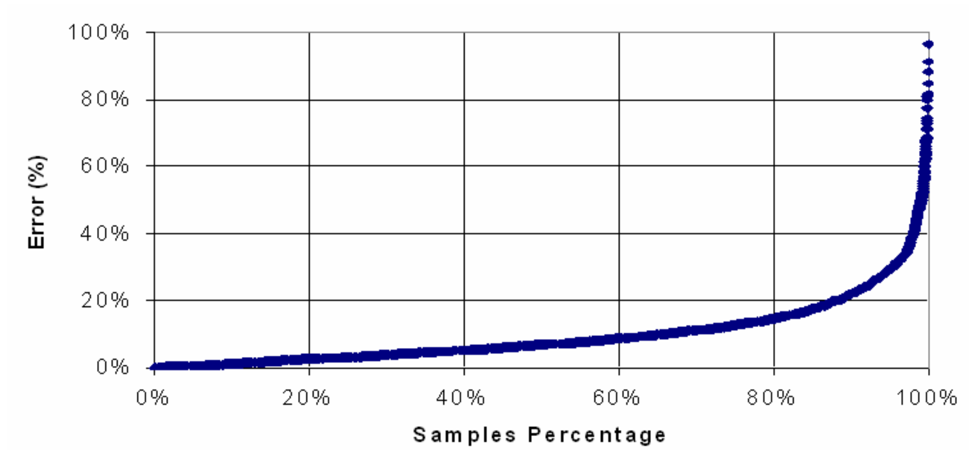
Figure B-1. Foote Creek Rim I Layout



Source: SeaWest, December 2004.

Winter is the season with the highest wind speeds in Wyoming, averaging 12.7 meters/second. Wind generation in the winter is nearly double the summer average of 10.16 MW per hour. Winter wind generation averages 19.5 MW per hour.

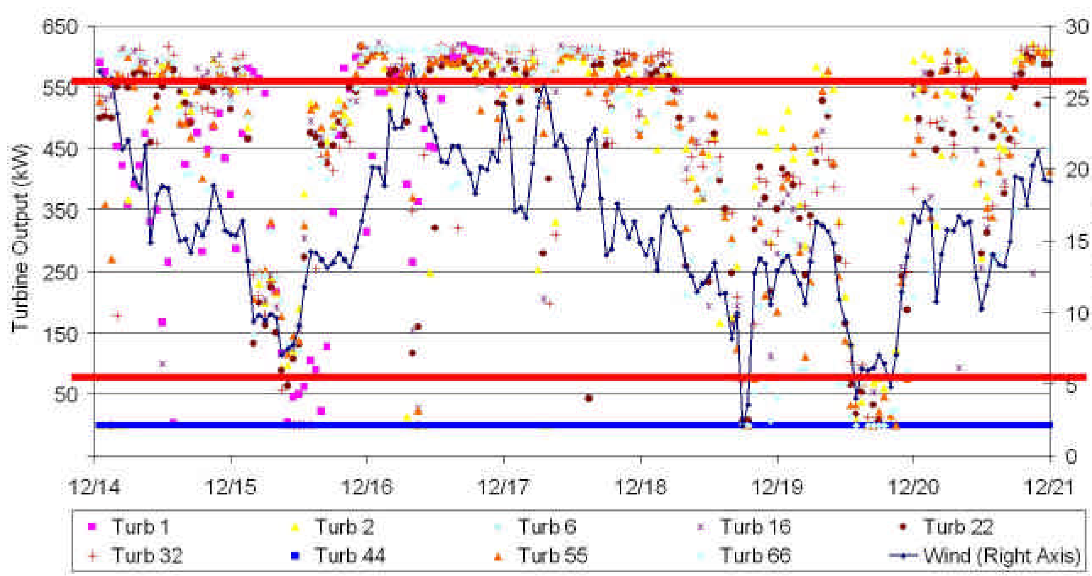
Figure B-2. Errors in Wyoming Wind Speed Measurements



Source: Calculated from SeaWest Data on Wind Speeds at Turbines and Meteorological Stations, December 2004. .

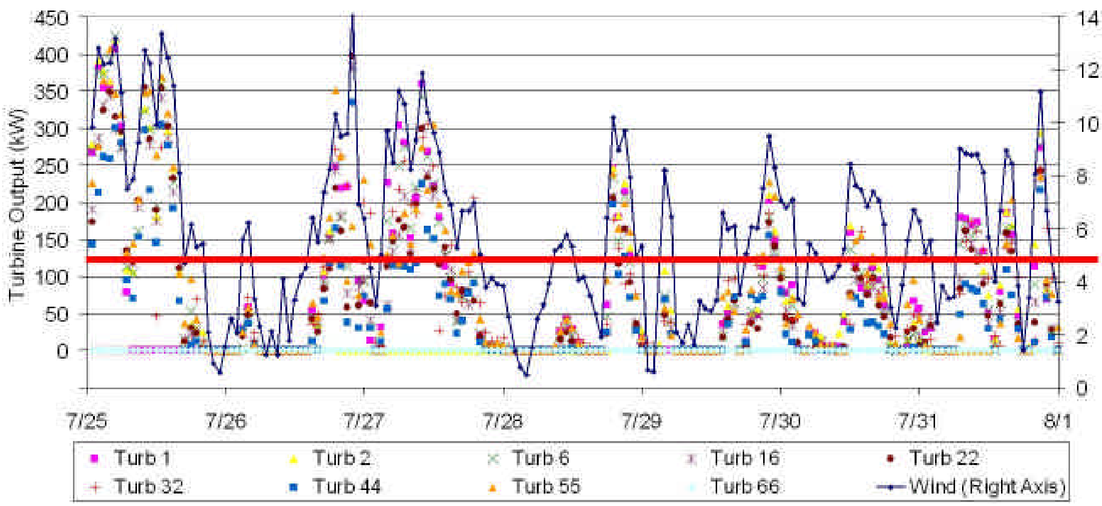
The Mitsubishi turbines used in Foote Creek Rim do not generate power at wind speeds below 4.8 meter/second or above 27 meters/second (if temperatures are very cold, the turbines will cut off at lower speeds). These cut-in and cut-out speeds are shown as red lines in Figures B-3 and B-4. In Figure B-3, the blue line at the bottom of the graph indicates that turbine #44 was out of service (probably for scheduled maintenance) during the week of December 14-20, 2003. As shown in Figure B-4, summer wind speeds never reached the 27 meters/second cut-off. On average, summer wind speeds were 8.6 meters/second. During this week, turbine #66 was out of service, as seen by the aqua line at the bottom of Figure B-4.

Figure B-3. Wind Speed and Turbine Output in Winter



Source: Calculated from SeaWest Data on Wind Speeds at Turbines and Meteorological Stations, December 2004.

Figure B-4. Wind Speed and Turbine Output in Summer



Source: Calculated from SeaWest Data on Wind Speeds at Turbines and Meteorological Stations, December 2004.

Appendix C. Model Snapshots

The following three screen snapshots illustrate how the economic model is structured, with Input, Output, and Data & Calculations worksheets.

Figure C-1. Wind Battery Economic Model Input Page

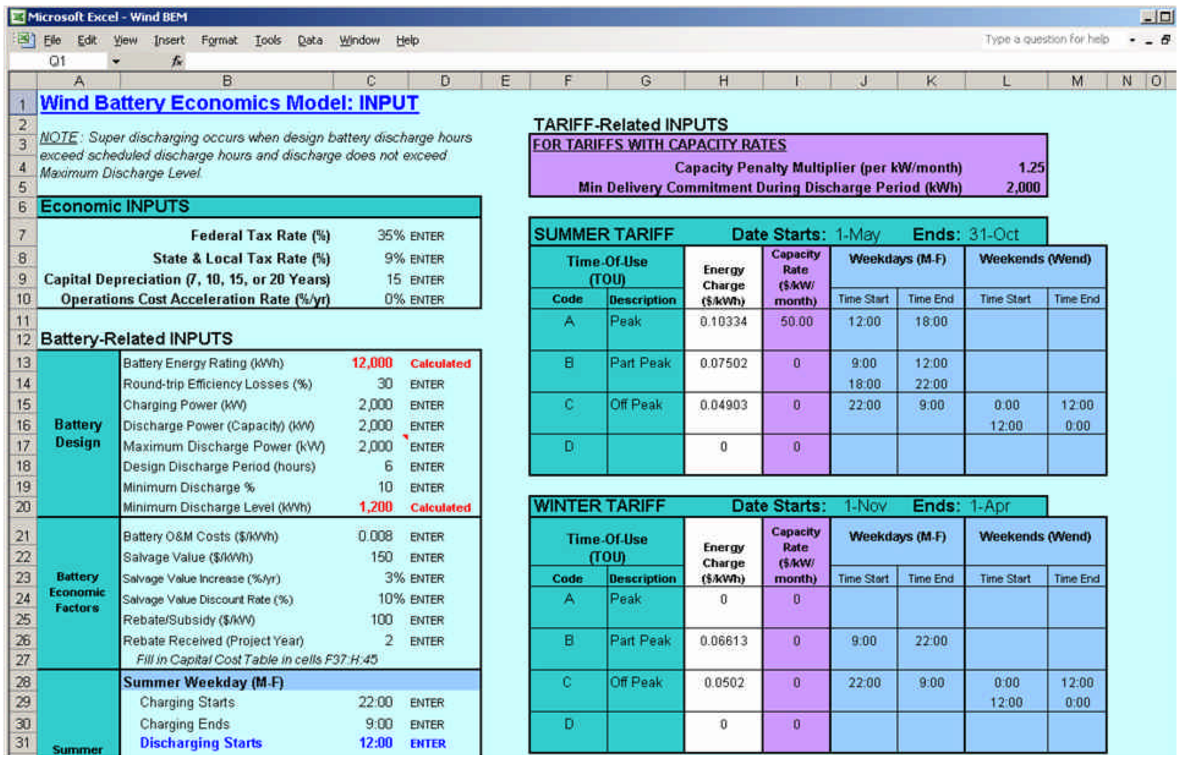
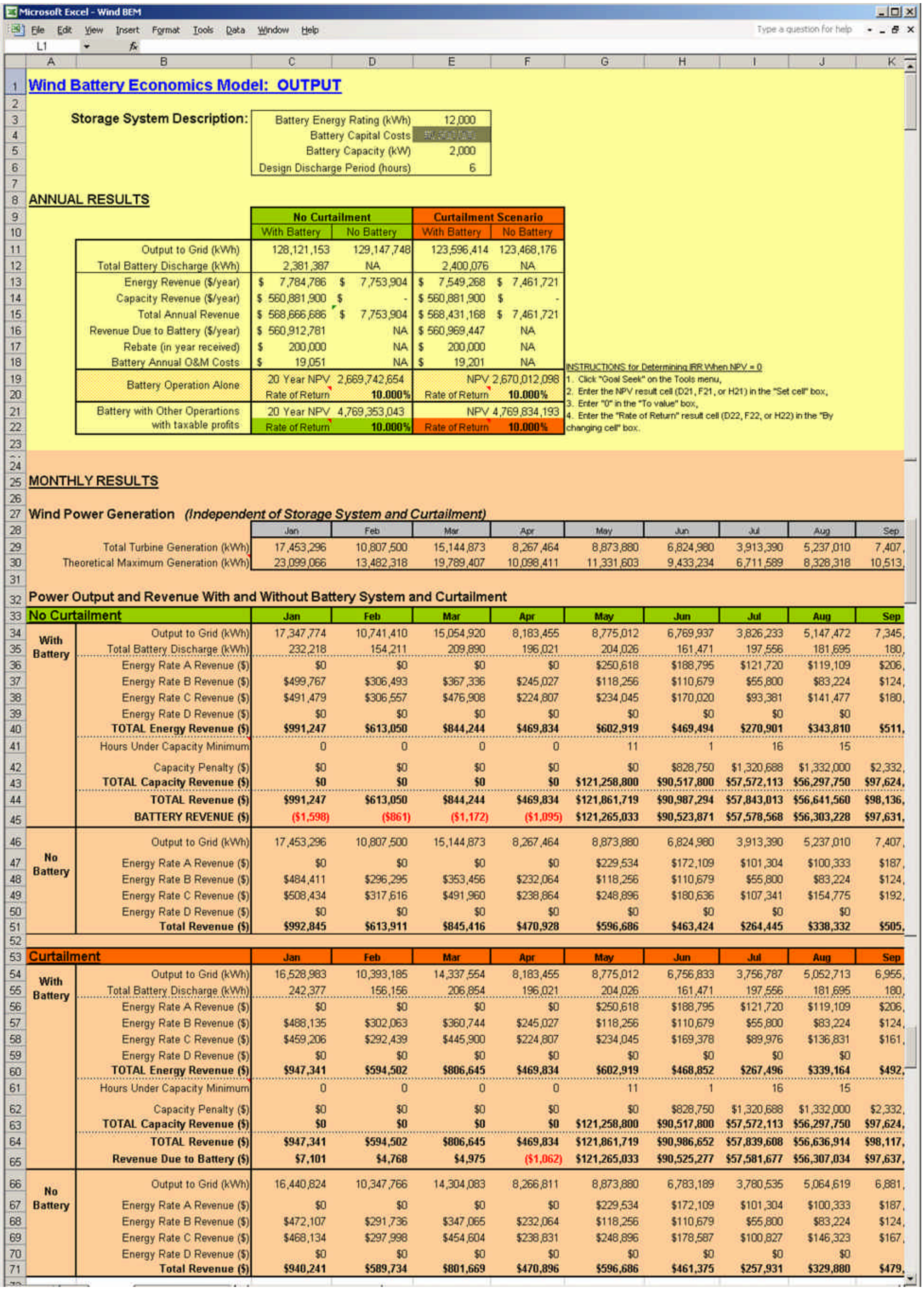


Figure C-2. Wind Battery Economic Model Output Page



Microsoft Excel - Wind BEM

Wind Battery Economics Model: OUTPUT

Storage System Description:

Battery Energy Rating (kWh)	12,000
Battery Capital Costs	[redacted]
Battery Capacity (kW)	2,000
Design Discharge Period (hours)	6

ANNUAL RESULTS

	No Curtailment		Curtailment Scenario	
	With Battery	No Battery	With Battery	No Battery
Output to Grid (kWh)	128,121,153	129,147,748	123,596,414	123,468,176
Total Battery Discharge (kWh)	2,381,387	NA	2,400,076	NA
Energy Revenue ($/year)	$ 7,784,786	$ 7,753,904	$ 7,549,268	$ 7,461,721
Capacity Revenue ($/year)	$ 560,881,900	$ -	$ 560,881,900	$ -
Total Annual Revenue	$ 568,666,686	$ 7,753,904	$ 568,431,168	$ 7,461,721
Revenue Due to Battery ($/year)	$ 560,912,781	NA	$ 560,969,447	NA
Rebate (in year received)	$ 200,000	NA	$ 200,000	NA
Battery Annual O&M Costs	$ 19,051	NA	$ 19,201	NA
Battery Operation Alone	20 Year NPV	2,669,742,654		NPV 2,670,012,098
	Rate of Return	10.000%	Rate of Return	10.000%
Battery with Other Operartions with taxable profits	20 Year NPV	4,769,353,043		NPV 4,769,834,193
	Rate of Return	10.000%	Rate of Return	10.000%

INSTRUCTIONS for Determining IRR When NPV = 0
1. Click "Goal Seek" on the Tools menu,
2. Enter the NPV result cell (D21, F21, or H21) in the "Set cell" box,
3. Enter "0" in the "To value" box,
4. Enter the "Rate of Return" result cell (D22, F22, or H22) in the "By changing cell" box.

MONTHLY RESULTS

Wind Power Generation ***(Independent of Storage System and Curtailment)***

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Total Turbine Generation (kWh)	17,453,296	10,807,500	15,144,873	8,267,464	8,873,880	6,824,980	3,913,390	5,237,010	7,407,
Theoretical Maximum Generation (kWh)	23,099,066	13,482,318	19,789,407	10,098,411	11,331,603	9,433,234	6,711,589	8,328,318	10,513,

Power Output and Revenue With and Without Battery System and Curtailment

No Curtailment		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
With Battery	Output to Grid (kWh)	17,347,774	10,741,410	15,054,920	8,183,455	8,775,012	6,769,937	3,826,233	5,147,472	7,345,
	Total Battery Discharge (kWh)	232,218	154,211	209,890	196,021	204,026	161,471	197,556	181,695	180,
	Energy Rate A Revenue ($)	$0	$0	$0	$0	$250,618	$188,795	$121,720	$119,109	$206,
	Energy Rate B Revenue ($)	$499,767	$306,493	$367,336	$245,027	$118,256	$110,679	$55,800	$83,224	$124,
	Energy Rate C Revenue ($)	$491,479	$306,557	$476,908	$224,807	$234,045	$170,020	$93,381	$141,477	$180,
	Energy Rate D Revenue ($)	$0	$0	$0	$0	$0	$0	$0	$0	
	TOTAL Energy Revenue ($)	**$991,247**	**$613,050**	**$844,244**	**$469,834**	**$602,919**	**$469,494**	**$270,901**	**$343,810**	**$511,**
	Hours Under Capacity Minimum	0	0	0	0	11	1	16	15	
	Capacity Penalty ($)	$0	$0	$0	$0	$0	$828,750	$1,320,688	$1,332,000	$2,332,
	TOTAL Capacity Revenue ($)	**$0**	**$0**	**$0**	**$0**	**$121,258,800**	**$90,517,800**	**$57,572,113**	**$56,297,750**	**$97,624,**
	TOTAL Revenue ($)	**$991,247**	**$613,050**	**$844,244**	**$469,834**	**$121,861,719**	**$90,987,294**	**$57,843,013**	**$56,641,560**	**$98,136,**
	BATTERY REVENUE ($)	**($1,598)**	**($861)**	**($1,172)**	**($1,095)**	**$121,265,033**	**$90,523,871**	**$57,578,568**	**$56,303,228**	**$97,631,**
No Battery	Output to Grid (kWh)	17,453,296	10,807,500	15,144,873	8,267,464	8,873,880	6,824,980	3,913,390	5,237,010	7,407,
	Energy Rate A Revenue ($)	$0	$0	$0	$0	$229,534	$172,109	$101,304	$100,333	$187,
	Energy Rate B Revenue ($)	$484,411	$296,295	$353,456	$232,064	$118,256	$110,679	$55,800	$83,224	$124,
	Energy Rate C Revenue ($)	$508,434	$317,616	$491,960	$238,864	$248,896	$180,636	$107,341	$154,775	$192,
	Energy Rate D Revenue ($)	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Revenue ($)	**$992,845**	**$613,911**	**$845,416**	**$470,928**	**$596,686**	**$463,424**	**$264,445**	**$338,332**	**$505,**

Curtailment		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
With Battery	Output to Grid (kWh)	16,528,983	10,393,185	14,337,554	8,183,455	8,775,012	6,756,833	3,756,787	5,052,713	6,955,
	Total Battery Discharge (kWh)	242,377	156,156	206,854	196,021	204,026	161,471	197,556	181,695	180,
	Energy Rate A Revenue ($)	$0	$0	$0	$0	$250,618	$188,795	$121,720	$119,109	$206,
	Energy Rate B Revenue ($)	$488,135	$302,063	$360,744	$245,027	$118,256	$110,679	$55,800	$83,224	$124,
	Energy Rate C Revenue ($)	$459,206	$292,439	$445,900	$224,807	$234,045	$169,378	$89,976	$136,831	$161,
	Energy Rate D Revenue ($)	$0	$0	$0	$0	$0	$0	$0	$0	
	TOTAL Energy Revenue ($)	**$947,341**	**$594,502**	**$806,645**	**$469,834**	**$602,919**	**$468,852**	**$267,496**	**$339,164**	**$492,**
	Hours Under Capacity Minimum	0	0	0	0	11	1	16	15	
	Capacity Penalty ($)	$0	$0	$0	$0	$0	$828,750	$1,320,688	$1,332,000	$2,332,
	TOTAL Capacity Revenue ($)	**$0**	**$0**	**$0**	**$0**	**$121,258,800**	**$90,517,800**	**$57,572,113**	**$56,297,750**	**$97,624,**
	TOTAL Revenue ($)	**$947,341**	**$594,502**	**$806,645**	**$469,834**	**$121,861,719**	**$90,986,652**	**$57,839,608**	**$56,636,914**	**$98,117,**
	Revenue Due to Battery ($)	**$7,101**	**$4,768**	**$4,975**	**($1,062)**	**$121,265,033**	**$90,525,277**	**$57,581,677**	**$56,307,034**	**$97,637,**
No Battery	Output to Grid (kWh)	16,440,824	10,347,766	14,304,083	8,266,811	8,873,880	6,783,189	3,780,535	5,064,619	6,881,
	Energy Rate A Revenue ($)	$0	$0	$0	$0	$229,534	$172,109	$101,304	$100,333	$187,
	Energy Rate B Revenue ($)	$472,107	$291,736	$347,065	$232,064	$118,256	$110,679	$55,800	$83,224	$124,
	Energy Rate C Revenue ($)	$468,134	$297,998	$454,604	$238,831	$248,896	$178,587	$100,827	$146,323	$167,
	Energy Rate D Revenue ($)	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Revenue ($)	**$940,241**	**$589,734**	**$801,669**	**$470,896**	**$596,686**	**$461,375**	**$257,931**	**$329,880**	**$479,**

Figure C-3. Wind Battery Economic Model Data and Calculation Page