Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Electricity Market.

Andrew M Knight, Hamid Zareipour, Abiola Adebayo

University of Calgary

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BACKGROUND

This report provides a summary of modeling, carried out at the University of Calgary, which aims to illustrate how an energy storage (ES) facility connected to the transmission system may operate within the Alberta Interconnected Electric System (AIES). The work has been financially supported by Alberta Department of Energy funding to the University of Calgary, independently from the AESO. Detailed simulation results have been provided to the AESO to aid in their determination of an appropriate tariff treatment for ES. This report is intended to provide a summary of the modeling approach used, the range of cases studied and sample results to highlight some of the observations made from the results. This report does not make any inferences, guidelines or suggestions on potential tariff treatment.

An agreed statement of work between AESO and the University of Calgary defined the goal of the study to perform operation and economic dispatch modeling of transmission connected storage in Alberta. The resulting impact of this operation on requirements for transmission facilities is out of the scope of this study. As an initial starting point, AESO collected stakeholder input on potential storage facilities (size and technology) that may be of interest to market participants. Based on the information from stakeholders, university researchers identified a series of example cases for detailed study. These cases do not match the exact characteristics of any of the data sets provided by stakeholders, but are designed to be representative of typical storage systems of the types and sizes described by stakeholders.

Operational dispatch modeling is predicted using a formal mathematical optimization process, implemented using the GAMS (General Algebraic Modeling System) tool and data on the actual hourly merit order curves for every hour of operation over 260 weeks from January 2010 through to December 2014. The model used predicts the operations of an ES facility that is rationally attempting to maximize operating profit through arbitrage. It does not model operations in ancillary services markets; it is not yet clear how different types of energy storage may operate in these markets.

METHODOLOGY

In order to predict the operation of a ES facility as an arbitrage project, a simulation is designed to answer the relatively simple question "when should an ES facility operate in order to maximize its operating profit?" Operating profit, p_{op} is defined as

$$p_{op} = r_{dis} - c_{ch} - c_{op} \tag{1}$$

where r_{dis} is revenue from discharging, c_{ch} is cost of charging and c_{op} is operating cost. The first two components of operating profit can be calculated using similar methods for all ES technologies. Assuming that the facility operates at constant power in any given hour the discharge revenue and charging costs can be written as

$$r_{dis} = \sum_{k=1}^{N} P_k \Pi_k \quad if \quad P_k > 0 \tag{2}$$

$$c_{ch} = \sum_{k=1}^{N} |P_k| \left(\Pi_k + T_{ek} \right) \quad if \quad P_k < 0 \tag{3}$$

where P_k is the power flow at hour k, Π_k is the market price for energy at hour k, and $T_{e\,k}$ is the variable metered energy component of Rate DTS. N is the duration of the optimization period. Note that positive power is defined as discharging, supplying to the transmission system and negative power is charging, withdrawing from the transmission system.

Operating costs are a function of the specific ES technology being used. In the all cases except Compressed Air Energy Storage (CAES), operating costs are defined as:

$$c_{op} = \sum_{k=1}^{N} |P_k| \left(c_{om} + c_{tr} \right) + T_{fix} \tag{4}$$

In (4) c_{om} is a variable operation and maintenance cost, c_{tr} is volume trading cost and T_{fix} is the fixed component of Rate DTS (comprised of both the billing capacity and system support services charges). For CAES, the cost of gas when discharging also needs to be included, and the operating cost is modified to include an additional term

$$c_{op-CAES} = c_{op} + \sum_{k=1}^{N} |P_k| h \Pi_{gas} \quad if \quad P_k > 0 \tag{5}$$

where h is the heat rate and Π_{gas} is the price of natural gas. Values for variables used to calculate operating costs are given in Appendix A.

Constraints are placed on the optimization based on storage capacity, power rating, and conversion and storage efficiencies such that the facility cannot discharge energy that is not available. For the purposes of the study, it is assumed that the stated storage capacity is the usable storage capacity, i.e. all units are capable of being fully discharged, and that storage capacity is constant over the lifetime of the study.

With knowledge of market prices, formal mathematical optimization can be implemented. In this study, the GAMS software tool is used, with results presented in Microsoft Excel. The optimization period N is an open variable. After some investigation of the relative merits of computational time and simulation artefacts, the optimization window used in this study is 168 hours, one week. Optimization with a 24-hour window was considered, but requires substantially more computational effort, and can introduce unwanted simulation results. A system that is designed to optimize operational profit over only 24 hrs will always be fully discharged at the end of the 24-hr period, irrespective of the price in hour 24 and may return results that are dependent on the specific time of day that the window is initialized. There are techniques to avoid this issue (such as rolling windows) but as mentioned they require a substantial increase in computational complexity.

The optimization simulation acts to maximize the operating profit in each week (168 hrs) and repeats this process 260 times to predict the operation of an ES facility over the 5-year period from January 2010 to December 2014.

WHOLESALE ELECTRICITY PRICE

The above optimization process defines an operation based solely on market price. To determine the market price, the study uses actual merit order curves for each hour of the simulation study period (2010-2014). If an ES facility is relatively small (<10MW) we assume that the operations of the facility will have negligible impact on the market price. In the remainder of this report, this type of facility is termed a “Price Taker”. In this case, with knowledge of actual market prices over the study period, the optimization is relatively straightforward.

The situation with a larger ES facility is more complex; new loads and additional generation will impact the market price. In this report, this type of facility is termed a “Price Maker”. The impact of additional generation will be twofold: (1) additional offers in the merit order will change the price for a given demand; (2) generators in the system may change their offer strategy, based on the actions of the new supply. This study accounts for changes in the merit order by inserting offers into the merit order, calculating new merit order curves and quantifying the impact of new offers, *assuming other market participants do not change their offering strategy*. At a given hour, the full merit order curve is constructed, based on publically available historical data. Cross-referencing this curve with the actual pool price, it is possible to determine an “equivalent system demand”. (This figure may not be the actual historical demand due to operational constraints such as transmission must-run (TMR) requirements.) Inserting new offer blocks in 10MW increments at $0/MWh, it is possible to calculate a new price as the intercept of the modified merit order curve and the calculated equivalent system demand. This process is conducted for all 43,680 hours in the model period. After completing this process, it is possible to create a *price sensitivity curve* for each hour, an example of which is shown in Figure 1. Here, the original energy price for the hour was $100/MWh. Adding between 10MW and 50MW additional supply, the price for the same system demand would be approximately $82/MWh. If the additional supply is between 100MW and 150MW, the price would be approximately $65/MWh.

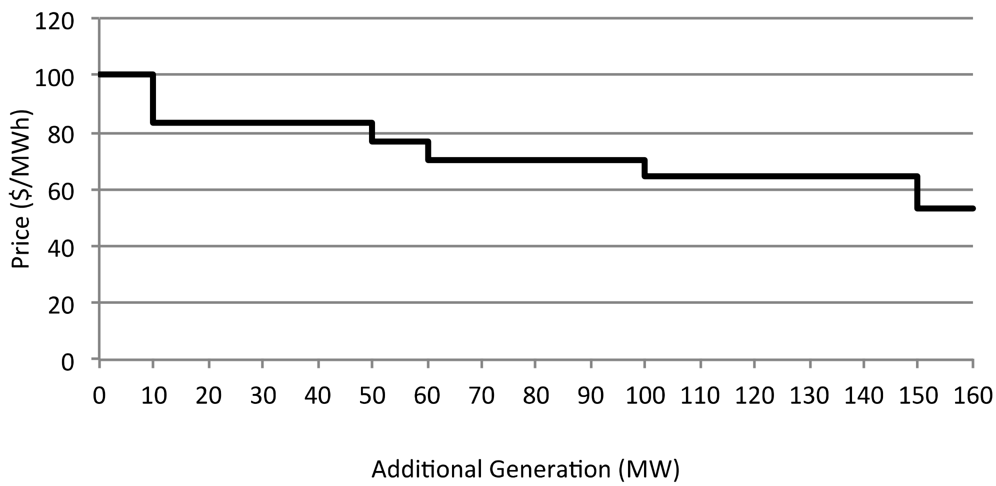

Figure 1 Example price sensitivity curve

Using this approach, the study is able to quantify the potential impact of additional supply on market price. As such, the optimization can determine both the optimal time and volume to offer to the market.

The merit order curves are also used to determine price increases due to the additional power requirement of an ES facility when charging. Adding the charging power to the equivalent system demand, the historical merit order data can be used to determine the likely price when charging.

It is important to stress that the above process accounts for the impact of an ES facility on energy prices, *assuming all other system participants maintain their operating strategies unchanged*. As market participants are likely to change their strategies in response to large new sources of supply, the maximum power under consideration in the study is limited to 150MW.

CASES STUDIED

Based on the input provided to AESO by stakeholders, the following cases were chosen as representative of potential arbitrage projects in Alberta.

Table 1 ES Cases used in the Study

Technology	Model	Power Rating (MW)	Capacity (MWh)
Lithium Ion Battery	Price Taker	8	40
Sodium Sulphur Battery	Price Taker	8*	40
Vanadium Redox Flow Battery	Price Taker	8	40
Lithium Ion Battery	Price Maker	20	80
Sodium Sulphur Battery	Price Maker	20*	80
Vanadium Redox Flow Battery	Price Maker	20	80
Pumped Hydro	Price Maker	150	1500
Compressed Air	Price Maker	150	1500

* Sodium Sulphur systems are capable of surge discharging above the "rated" discharge rate.

All cases were studied with and without Rate DTS charges (at the rates described in Appendix A).

To illustrate the impacts of changes to model input variables, sensitivity analysis was carried out using the 8MW Li-Ion Price Taker model. Each of the following changes was applied separately, to allow comparison with the base case listed above

- Increase Conversion Efficiency by 10%
- Decrease Conversion Efficiency by 10%
- Increase Power Rating by 10%
- Increase Variable Operation & Maintenance Costs by 10% (excluding tariff charges)
- Increase Rate DTS tariff rates by 10%.

EXAMPLE RESULTS

A comprehensive set of results have been provided to the AESO. Examples of the types of results and trends that may be seen are provided in this report. As the aim of this report is not to comment on the relative merits of different storage technologies, direct comparison between technologies is not made and the specific technology types are not reported when carrying out side-by-side comparisons.

OPERATING SCHEDULE

The raw operating schedule for all hours is provided. An example week is shown in Figure 2, normalized to % of rated power flow. Positive power flow indicates discharging operations, supply to the system; negative power flow indicates charging operations, withdrawal from the system, the horizontal axis is hour number. The simulations have a start date of January 1, 2010, therefore the initial week for simulation begins on a Friday. i.e. hours 1-24 occur on Friday, 24-72 are weekend, 73-168 are Monday through Thursday.

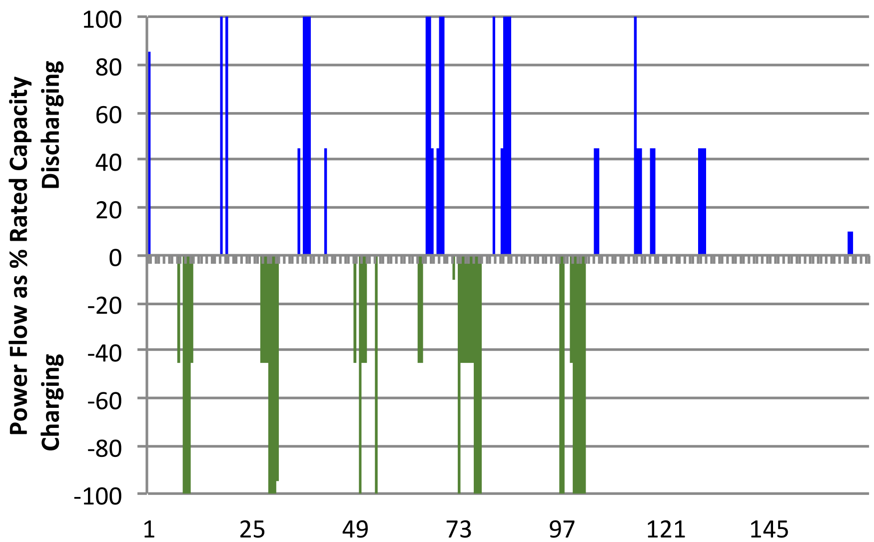

Figure 2 Example operating schedule

Taking the information from the raw schedule, it is possible to evaluate how often, in the 260 week period, an ES facility may operate in either charging or discharging mode for a particular hour of the week. Calculating this frequency data it is also possible to calculate the frequency at which a facility is operating above a given percentage of the rated power. This data is plotted for one of the 20MW facilities in Figure 3 and Figure 4. Figure 3 gives the information for all weeks in the study, Figure 4 presents the data for spring 2010. Both plots confirm what may generally be expected. ES units are typically charging (withdrawing from the system) during the overnight hours and usually discharge (supply to the system) during the hours from mid morning to late evening.

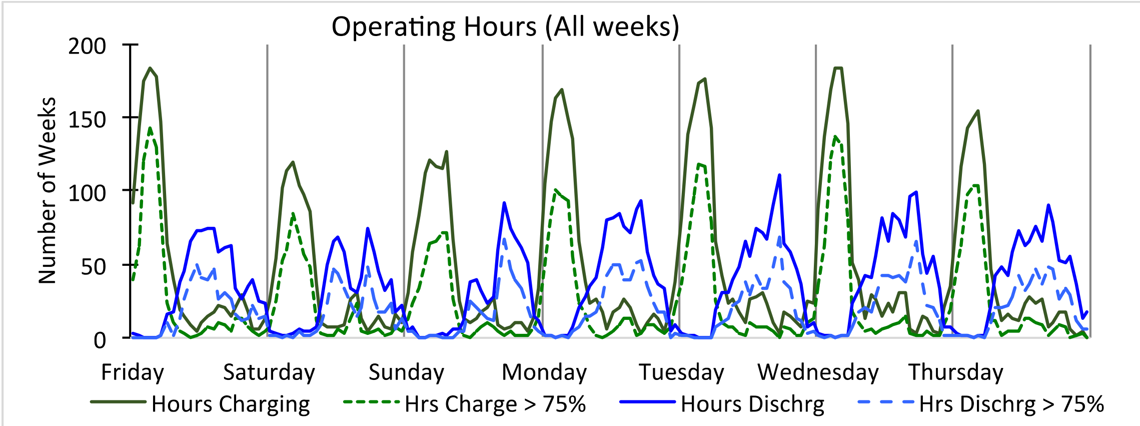

Figure 3 Frequency of operation at a given hour, all weeks, 20MW facility

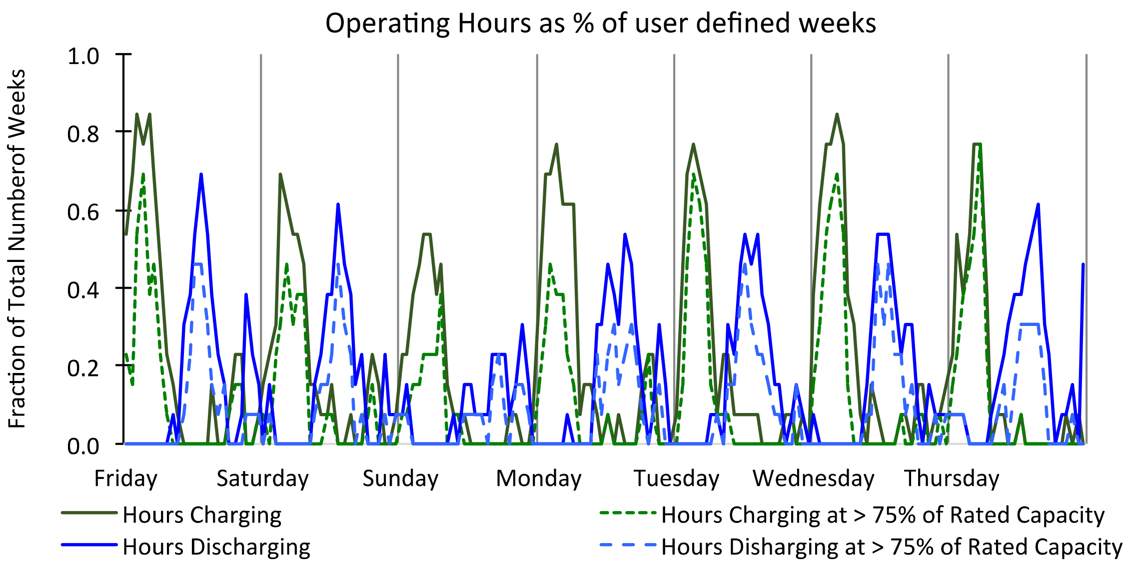

Figure 4 Frequency of operation at a given hour, defined period (In this case spring 2010, (13 weeks, starting week 13)

The data as presented in Figure 3 can be used to illustrate the impact of size on operations, and to indirectly confirm that the optimization process acts as intended. Figure 5 and Figure 6 plot similar data for an 8MW Price Taker and 150MW Price Maker facility respectively. Comparing these to the 20MW price maker Figure 3, it is clear that the optimized scheduling is limiting the output power as the power rating increases. In the 8MW price taker (Figure 5), if the facility operates, it is usually operating above 75% of rated power. The charge / discharge frequencies are similar in Figure 3 and Figure 5, but it can be seen that the large unit spends a smaller fraction of time operating above 75% of rated power. This trend is further emphasized with the 150MW facility in Figure 6. This behaviour is rational; the small unit has no impact on price, so operates to the maximum when conditions are favourable. Larger offering volumes reduce the market price, and the optimization can be seen to limit the offer size so as to not negatively impact revenue.

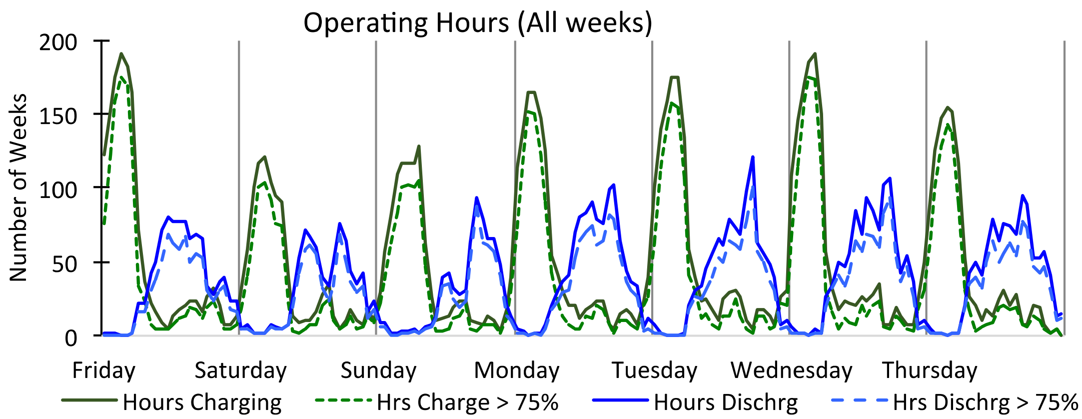

Figure 5 Operation frequency at a given hour, 8MW Price Taker unit

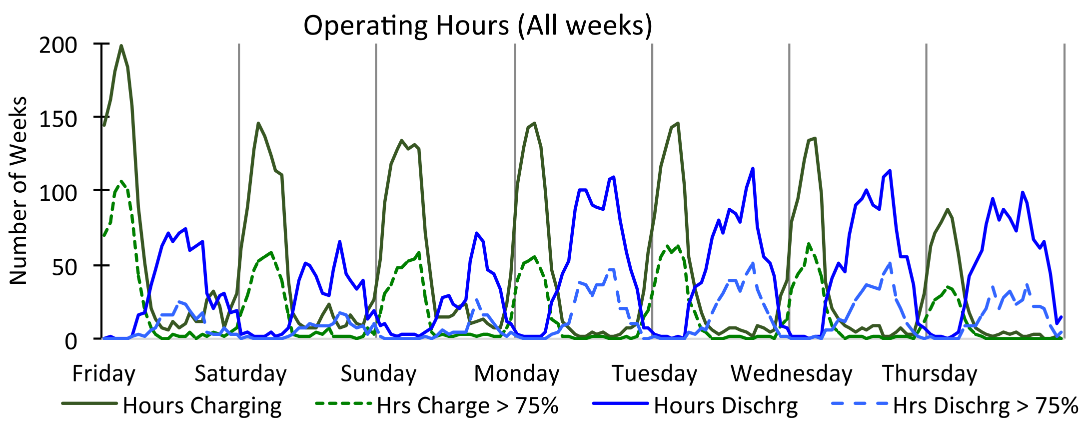

Figure 6 Operation frequency at a given hour, 150MW Price Maker unit.

MONTHLY SUMMARY DATA

The net operating statistics for each month are collated to provide summary data on: the net energy flow to / from the grid; monthly revenue and operating costs; monthly profit; whether or not the system was withdrawing from the system during the period of peak demand for the month. Examples for one of the 20MW facilities, simulated without Rate DTS charges, are plotted in Figure 7 and Figure 8. It can be seen that the energy flows vary from month to month, with resulting impacts on profit. Over the past 5 years, an ES facility would have seen substantial variation in monthly profit.

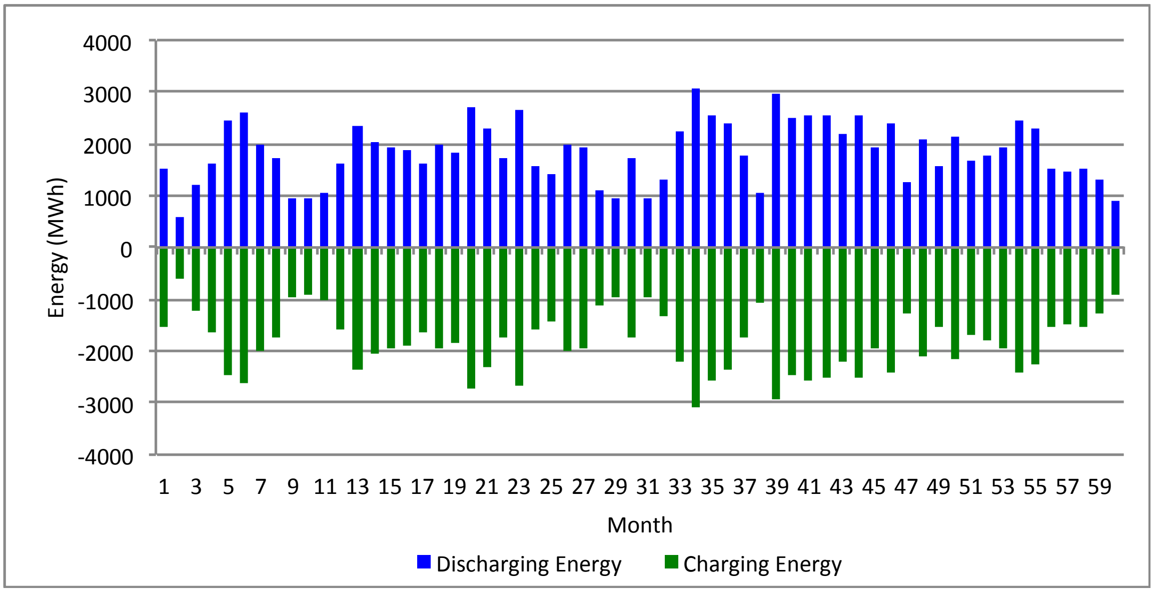

Figure 7 Monthly energy flows for one of the 20MW facilities

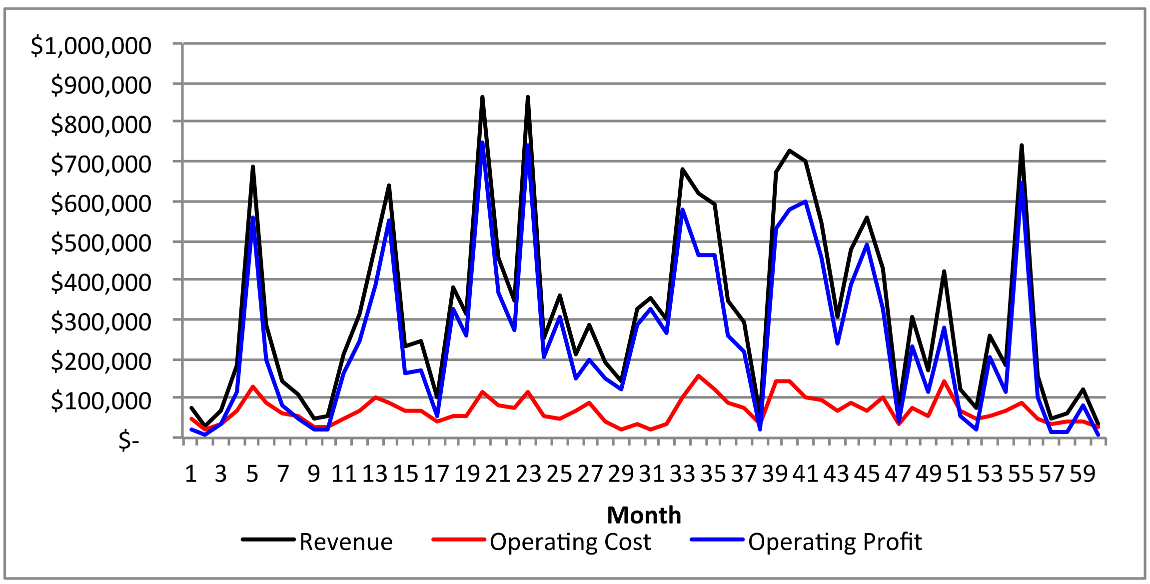

Figure 8 Monthly variation in revenue, costs and operating profit for one of the 20MW facilities, without DTS

CORRELATION OF OPERATION WITH SYSTEM DEMAND

The modeling in this study schedules operation to maximize profit, based solely on market prices for energy. As such, operation only relates to system demand indirectly as a function of the merit order curves. The simulation results allow the correlation of schedule, as a percentage of rated power, against quintile of system demand in any given period. The time period may be customized to allow different seasons to be evaluated. Figure 9 plots the data for the full 5 year period, for the same 20MW facility considered in Figure 3 . This chart indicates that ES storage systems that only operate on an arbitrage basis: may be idle for a significant period of the time;

that they should *typically* charge (withdraw from the system) during periods of low demand; and that they should *typically* discharge (supply to the system) during periods of high demand. However, it can also be seen that the systems may charge even when the system demand is relatively high. This fact may be accounted for by the seasonal variation in system demand; relatively low demand in one season may still be above the 80th percentile of overall demand. Figure 10 presents the operation vs. system demand frequency information for the 13-week period in spring 2010 that is also used for Figure 4. Here, it is clearly seen that at high system demand, the ES facility discharges; at low system demand, the ES facility charges.

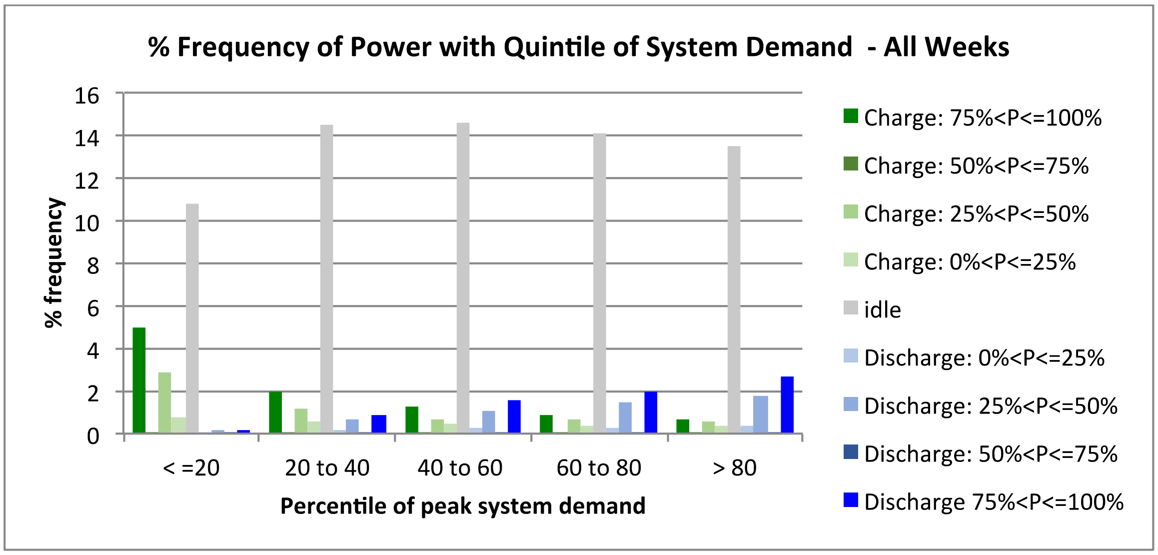

Figure 9 Frequency of operation as a function of system demand, all hours (20MW Facility)

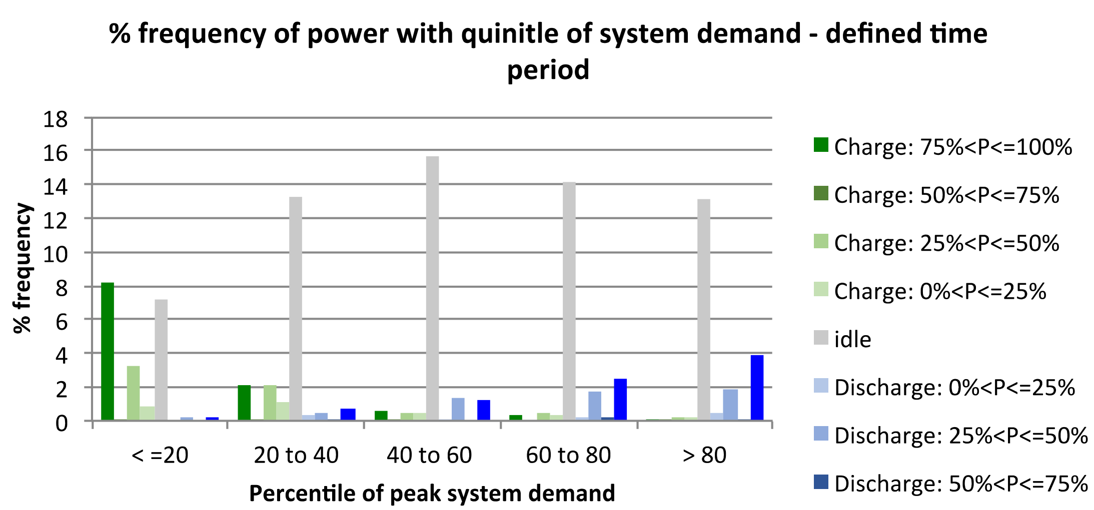

Figure 10 Operation as a function of system demand, Spring 2010: 13 weeks starting week 13 (20 MW Facility)

Impact of Rate DTS Charges

The figures in the previous section are all for a system that is operating without being subject to Rate DTS charges. A similar set of detailed results is created for all 8 ES cases operating with Rate DTS charges applied to charging intervals. In this report, these detailed plots are not duplicated, but steps to show the relative impacts are presented. Figure 11 plots the average weekly power flow for an 8MW facility, with and without Rate DTS charges. As expected, the imposition of Rate DTS charges reduces power flow not only when charging, but also when discharging. The reduction in power flow has a small impact on revenue as presented in Table 2. However, the Rate DTS charges have a significant impact on operating costs, which are increased by 45% over the 5-year period, resulting in a 15.9% reduction in operating profit.

Table 3 provides side-by-side comparison of the impact of Rate DTS charges for all 8 cases (note that these cases are not listed in the same order as the technologies in Table 1).

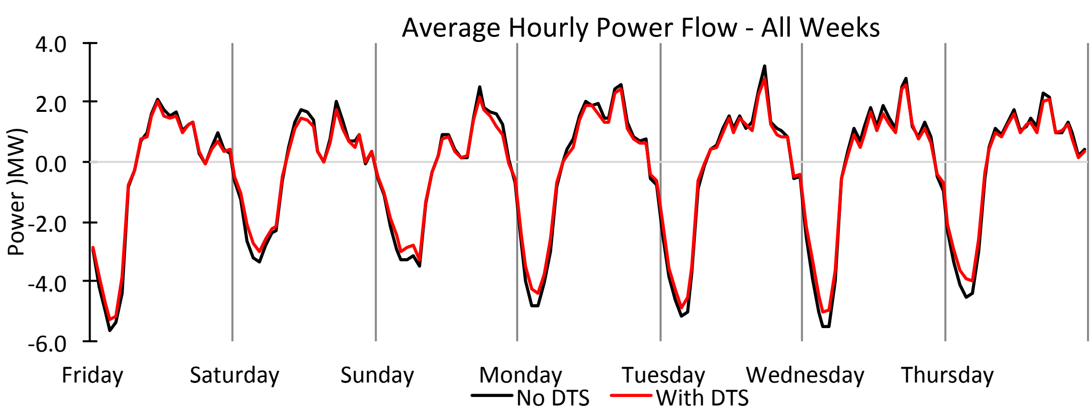

Figure 11 Average weekly power flow with and without DTS (8MW Facility)

Table 2 Impact of DTS on an 8MW Battery

Year	MWhr IN (Reduction)	MWHr Out (Reduction)	Revenue Reduction	Cost Increase	Profit reduction
TOTAL	11.23%	11.44%	2.16%	45.04%	15.90%
2010	13.24%	13.45%	3.37%	58.80%	30.68%
2011	11.53%	11.70%	1.92%	38.15%	11.52%
2012	8.31%	8.48%	1.30%	48.88%	13.33%
2013	7.60%	7.78%	0.87%	41.35%	11.96%
2014	16.76%	17.14%	5.86%	42.27%	28.06%

Table 3 Percentage Reductions in Operating Profit due to DTS, All Cases (Technology Omitted)

	8MW			20 MW			150MW	
TOTAL	15.9%	17.0%	14.5%	19.6%	21.1%	18.0%	16.3%	18.6%
2010	30.7%	27.9%	26.7%	36.1%	37.4%	32.5%	33.1%	39.8%
2011	11.5%	12.0%	9.3%	15.3%	14.7%	12.8%	12.3%	13.6%
2012	13.3%	13.0%	13.2%	15.9%	16.9%	15.9%	13.8%	16.3%
2013	12.0%	13.3%	12.7%	14.2%	15.2%	13.7%	10.5%	12.7%
2014	28.1%	35.2%	23.2%	36.9%	43.3%	33.1%	32.6%	35.6%

The DTS calculation terms in equations (1)-(5) do not include terms for coincident peak demand. The period of peak demand in any given month is only determined after the fact, and as such is difficult to include in a price-based optimization. This component of Rate DTS is applied to the operating costs after the fact, if necessary. The total incidences of this component being applied over the full 5 year period are summarized for each case in Table 4.

Table 4 Incidence of Charging During Peak Demand

Technology	Incidences
Li-Ion 8MW	1
NaS 8MW	3
VR 8MW	2
Li-Ion 20MW	0
NaS 20MW	3
VR 20MW	1
PHS 150MW	1
CAES 150MW	1

As the inclusion of Rate DTS charges impacts both charging costs and revenue opportunities, a direct calculation of the total amount paid in Rate DTS charges is not a full evaluation of the “cost” of Rate DTS. As an attempt to evaluate the “cost of Rate DTS”, monthly operating costs for the schedules with and without Rate DTS charges included are plotted for one of the 20MW facilities in Figure 12, together with the reduction in monthly operating profit when Rate DTS is considered.

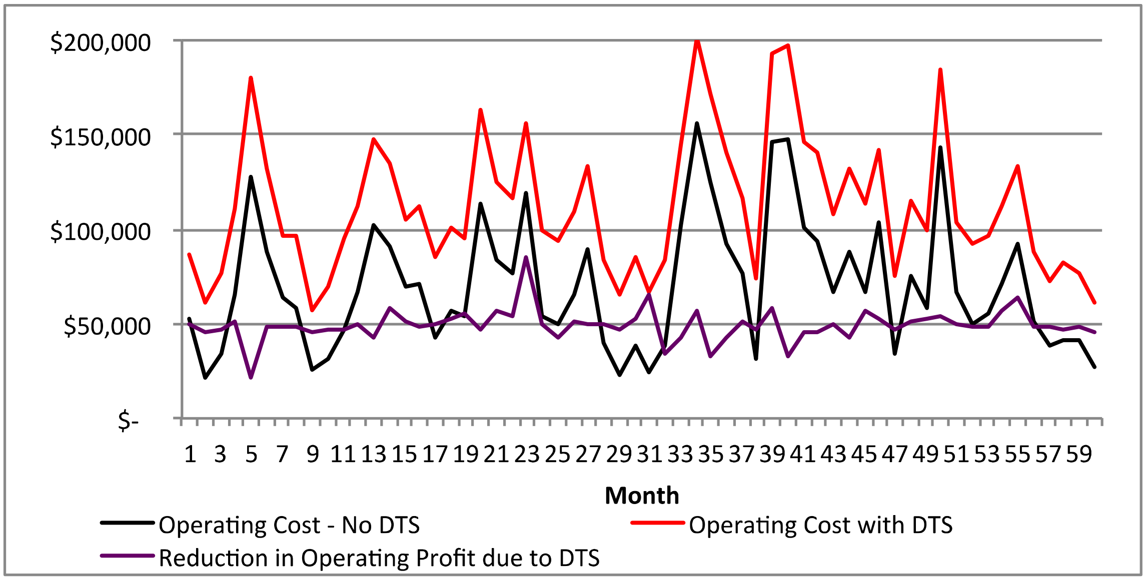

Figure 12 Impact of DTS on monthly operating costs and monthly operating profit, a 20MW ES facility.

Sensitivity Analysis

As stated above, sensitivity analysis is only carried out on the 8MW Li-Ion simulation. Each sensitivity case is run as a new optimization, to illustrate the impact of various input parameters. Sensitivity data is presented as percentage change relative to the initial simulation with no Rate DTS charges.

Table 5 Sensitivity analysis, percentage change relative to base case

	MWhr IN	MWHr Out	Revenue	Cost	Profit
Base Case no Rate DTS	0	0	0	0	0
Efficiency Increased 10%	7.4%	21.6%	8.4%	10.6%	7.7%
Efficiency Decreased 10%	-6.1%	-18.0%	-6.6%	-7.9%	-6.3%
Power Rating Increased 10%	5.5%	5.6%	6.2%	6.3%	6.2%
Capacity Increased 10%	5.7%	5.6%	5.8%	3.0%	6.7%
OM Cost Increased 10%	-4.3%	-4.4%	-0.4%	-0.8%	-0.3%
Base Case with Rate DTS	-11.2%	-11.4%	-2.2%	45.0%	-15.9%
Rate DTS Increased by 10%	-12.4%	-12.6%	-2.9%	47.2%	-17.6%
Additional Impact of Rate DTS Increase (Above Base Case with Rate DTS)	-1.3%	-1.4%	-0.8%	1.5%	-2.0%

The sensitivity analysis indicates that the conversion efficiency has a significant impact on profit, with 10% increase in efficiency resulting in 7.7% increase in operating profit; and 10% decrease in efficiency a 6.3% reduction in profit. Increasing either of power rating or storage capacity also results in a profit increase in the range of 6%-7%. Variable O&M costs have little impact on profit, with a 10% change only impacting profit by 0.3%.

Application of Rate DTS to the system has a significant impact, in this case 15.9% reduction in profit. If the Rate DTS tariff were to be 10% higher, the operating profit is reduced by 17.9% relative to the no Rate DTS case. Comparing to the Base Case with rate DTS, a 10% increase in Rate DTS incrementally reduces operating profit by 2%.

Impact of Rate STS

Due to the fact that Rate STS is location-dependent, Rate STS has not been studied in detail. As with the other sensitivity analysis cases, a simulation applying both Rate DTS and Rate STS to the 8MW Li-Ion system has been carried out. This simulation assumes a Rate STS tariff of 3.4% of pool price when discharging. The net impact on operations over the 5-year period is an additional 5% reduction in energy flow, and a 5.5% reduction in operating profit. Operational patterns are not materially impacted.

SUMMARY

This report describes the approach used to develop models of arbitrage operations of energy storage facilities as they might operate in the Alberta ‘energy only’ market. The simulation results indicate that ES facilities would typically charge overnight and discharge during the daytime. Although operation is optimized with respect to price, results show that storage occurs during periods of low demand, and supply is made available during periods of high demand.

APPENDIX A – VARIABLE OPERATING COSTS

All charge and discharge operations are modeled with a trading change of \$0.412/MWh. Technology dependent variables are given in Table 6.

Table 6 Energy Storage Parameters

Technology	O & M Cost /per MWh	Conversion Efficiency	Storage Efficiency	Gas Cost $/KJ	Heat Rate
Lithium Ion Battery	$7	89.4%	99.7%	n/a	n/a
Sodium Sulphur Battery	$7	88.3%	100%	n/a	n/a
Vanadium Redox Flow Battery	$1	86.6%	99.7%	n/a	n/a
Lithium Ion Battery	$7	89.4%	99.7%	n/a	n/a
Sodium Sulphur Battery	$7	88.3%	100%	n/a	n/a
Vanadium Redox Flow Battery	$1	86.6%	99.7%	n/a	n/a
Pumped Hydro	$10	90%	100%	n/a	n/a
Compressed Air	$1.5	n/a	100%	5	4

Rate DTS Charges consist of Point of Delivery Charge, Regional System Charge and Bulk System Charge. It is assumed that the ES proponent will build, own, and operate their own substation such that the Rate PSC credit reduces the Point of Delivery component to a negligibly low figure. Should an ES proponent not take this approach, the Rate DTS charges will be materially higher than those calculated for this report.

The Regional System Charge and Bulk System Charges are calculated in two components; variable and fixed. Variable charges consist of a Bulk System Charge on metered energy at \$0.92/MWh plus a Regional System Charge of \$0.77/MWh. Operating Reserve Charge of 7.74% of the product of metered energy (used for charging) and pool price is also included as a variable cost. The fixed components are calculated as monthly charges of Billing Capacity of \$2181/MW at the maximum facility rating and System Support Services Charge of \$22/MW at the maximum facility rating. These charges are included in the optimization algorithm. The Coincident Metered Demand charge of \$7790/MW is added after the fact, for each month where charging operation coincided with peak demand, and is not included in the optimization algorithm.

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