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ORIGINAL PAPER

Simulation and optimization of a flow battery in an area regulation application

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Abstract Flow batteries have the potential to provide ancillary grid services such as area regulation. In this paper, a hypothetical 2 MW flow battery is simulated in an area regulation application to find the optimal energy-to-power ratio that maximizes the net present value (NPV) of a 10 year project based on a range of installation costs. Financial and operational results are presented, and candidate battery chemistries are discussed. A simplified model of battery installation costs (dollars per kW h) resulted in a positive NPV for installation costs below \$500 kW^{-1} h^{-1}. For installation costs between \$300 and \$500 kW^{-1} h^{-1}, an optimal energy-to-power ratio is 1.39. The traditional advantage of decoupling power and energy capacity may not be realized in area regulation; therefore hybrid flow batteries may be more appropriate. Zinc-bromine and iron-chromium chemistries might fit well with this application, along with lower-cost flow battery chemistries in the future.

Keywords Energy storage · Redox flow batteries · Area regulation · Redox flow cells · Flow batteries

1 Introduction

Redox flow batteries have the potential to provide a variety of grid storage services. A recent report by Sandia National Laboratories presents value propositions for energy storage in 17 distinct grid service applications, two of which are further sub-divided [1]. Redox flow batteries have the potential to fulfill the requirements of many of these applications. This paper focuses on the potential of redox flow batteries to provide area regulation ancillary grid services.

Area regulation is a compelling application due to the high monetary value assigned to the service, according to the same Sandia report. It is an ancillary grid service that matches grid capacity with consumer demand in real time. To maintain grid voltage and frequency values within preset limits, the power capacity of the grid must be closely matched to the actual grid demand at any given time. For example, if 100 people in a city simultaneously turn on or shut off a 100 W light bulb, the capacity demand would instantly go up or down, respectively, by 10 kW. In addition to normal grid energy capacity, the regional grid operator must pay for area regulation services that can respond to this real-time demand change by ramping up and down. “Up Regulation” is the term used to describe the regulation service that adds capacity to the grid. “Down Regulation” is the term used to describe the regulation service that removes capacity from the grid. Traditionally, area regulation has been provided by automatically controlled power plants that have the ability to quickly ramp up and down, such as gas turbines. Energy storage can also fulfill this application by absorbing energy for down regulation or discharging for up regulation. If the battery is fully charged, it can only be available for up regulation. Likewise, if the battery is fully discharged, it can only be available for down regulation.

In the area regulation market, a grid operator pays on a MW-per-hour basis for *available* capacity, even if the capacity is not used. The amount paid for an hour of

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availability usually depends on a market-based bidding approach, where plant operators submit bids each hour (in an hour-ahead market) to provide the service. This is the approach used in California. This can be different in other markets, depending on how the electrical grid is regulated in a particular market. Also, a regulation facility is not always used during the time in which it is paid to be available. A regulation plant or battery can receive revenue for an hour of available capacity even if no service is provided during that hour. It should also be noted that a battery providing these services must purchase and sell the energy it uses at the market rate. For example, the energy absorbed during down regulation must be purchased. The energy discharged during up regulation is sold at the same rate (assuming no time-of-use pricing structure). Since no storage technology is 100% efficient, more energy is always purchased than is sold, representing a net cost to the battery operator. A lower efficiency represents a larger cost. The cost also increases with the amount of regulation provided.

The installed cost of a flow battery can be characterized as a total cost per kW of power capacity, as a cost per kW h of energy capacity, or as a combination of the two. Costs include the stack components, balance of plant hardware, control system, inverter, electrolyte, infrastructure changes, and installation. The cost model used in this analysis uses a simplified approach by characterizing the installed cost on a per-kW h basis. Note that an energy-to-power ratio of 1 would yield the same cost on a per-kW and per-kW h basis. The energy-to-power ratios discussed in this analysis are relatively small, and while not equal, the cost per-kW and per-kW h would be on the same order of magnitude.

This paper analyzes the simulated performance of a generic redox flow battery in an area regulation service. Using real market data obtained from the California Independent Service Operator (CAISO), an optimal energy-to-power ratio for a range of battery costs is determined to maximize the net present value (NPV) of a hypothetical battery installation. Finally, the paper discusses the battery chemistries that might be well-suited to provide this service.

2 Simulation description

2.1 Assumptions

According to the Sandia report on energy storage, the typical size for an area regulation facility is between 1 and 40 MW. A 2 MW energy storage system was chosen for the power capacity of the hypothetical battery analyzed in this paper. The Sandia paper also reports the discharge time required for providing area regulation service ranges from 15 to 30 min. Therefore, this analysis conservatively assumes that the battery provides up regulation or down regulation for 30 min during each hour that it is available, and that the battery operator receives the market price revenue for each hour that it is available. Since it is not known whether charge or discharge services will be needed, the battery simulation used a binary random number generator ($0 =$ up regulation, $1 =$ down regulation) to determine which service would be provided. If the battery state of charge was above the threshold where it could not provide 30 min of down regulation, it was only made available for up regulation and only received the revenue for that service during that hour. Likewise, if the battery state of charge was below the threshold where it could not provide 30 min of up regulation, it was only made available for down regulation and only received the revenue for that service during that hour. If the battery was available for both up and down regulation, it received revenue for both services during that hour (since it is contractually providing both up and down availability to the ISO). Note that this is a simplified and conservative assumption since the battery could receive revenue for progressively smaller amounts of power capacity at the extreme states of charge. This marginal additional revenue is not included in this analysis.

The generic redox flow battery in this analysis was assumed to have a state of charge (SOC) range between 10 and 90%. This means that at full charge and discharge, the battery has 10% unreacted species in solution. This assumption will vary depending on the battery chemistry. Further, the overall round-trip efficiency of the battery was assumed to be 75%, consistent of symmetrical equivalent charge and discharge efficiencies ($\sqrt{0.75}$). Energy capacity and efficiency was assumed to remain constant over the battery lifetime.

Installed battery system costs were assumed to have a range between \$100 and \$500 $kW^{-1}\,h^{-1}$. Above \$500 $kW^{-1}\,h^{-1}$, the system appears to not be profitable. Area regulation market price data was obtained from published hourly price data on the CAISO website. The price data obtained was from 2008, and was increased using a 2.5% inflation rate to reflect current market rates. The electricity price was assumed to be \$163.3 $MW^{-1}\,h^{-1}$ for both the purchase and sale of electricity, which was the commercial electricity rate in California in September 2010 according to the Energy Information Administration [2].

Some other project financial assumptions were made regarding the installation of the 2 MW system. The analysis assumed a battery and project lifetime of 10 years and that 70% of the cost of the system was financed with an 8 year loan at 10% interest. Maintenance costs were assumed to be \$8 $MW^{-1}\,h^{-1}$ of discharged electricity [3]. Further income taxes for the operation were estimated at

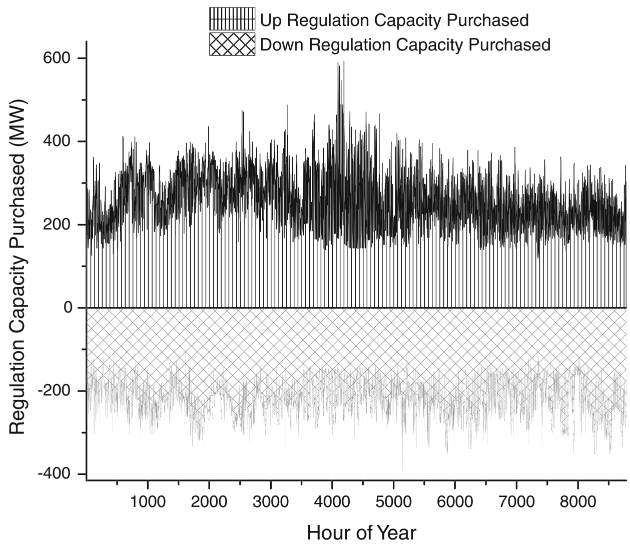

Fig. 1 The amount of up and down regulation capacity purchased by CAISO for every hour of 2008. Positive numbers represent up regulation purchases and negative numbers represent down regulation purchases [4]

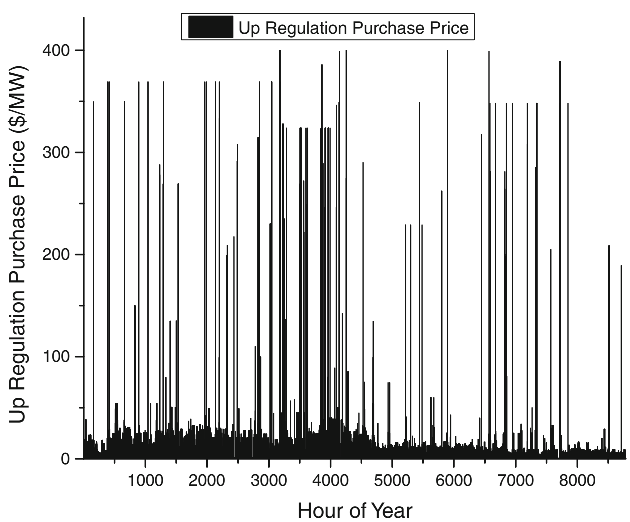

Fig. 2 The purchase price paid for 1 MW of up regulation capacity per hour in 2008 [4]

25%. The depreciation rate for the system was 10% per year for all 10 years of operation. An overall discount rate of 10% was used.

2.2 Operational constraints

The amount of required area regulation varies widely per hour, and is usually predicted by an algorithm specific to a grid operator. In 2008, the average amount of up regulation capacity purchased by CAISO per hour was 257 MW. The average amount of down regulation capacity purchased

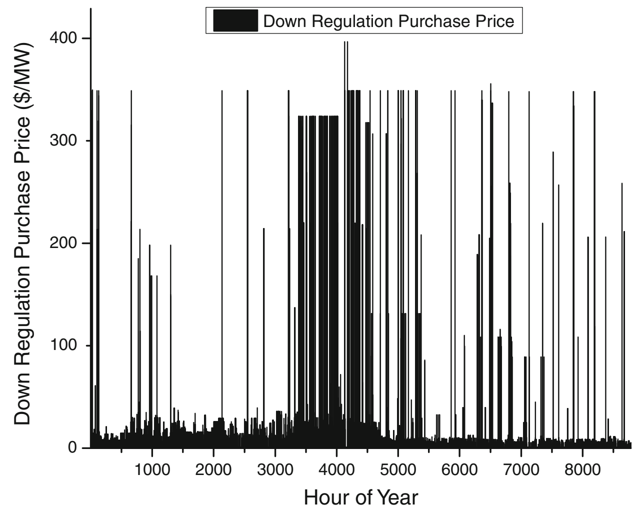

Fig. 3 The purchase price paid for 1 MW of down regulation capacity per hour in 2008 [4]

was 217 MW. Figure 1 shows the amount of up and down regulation capacity purchased by CAISO in each hour of 2008 [4]. Down regulation purchased is represented by a negative number in the graph. It is noteworthy that some capacity was always purchased every hour, so there was always a market to provide area regulation services.

The prices paid for regulation capacity varied even more widely. Some hours, price went as low as zero, and other hours the price reached as high as \$400 MW^{-1}. Figures 2 and 3 show the hourly up and down regulation prices paid, respectively, by CAISO in 2008. The average hourly up regulation price was \$14.89 MW^{-1}, while the average hourly down regulation price was \$17.32 MW^{-1} [4].

The initial state of charge of the battery was set at 75%, with a guessed usable energy capacity of 6 MW h (representing the operational capacity between 10 and 90% SOC). In the first hour of the simulated year, a random number generator selected whether the battery would provide 30 min of up regulation (discharge operation) or 30 min of down regulation (charge operation) during each hour. In either case, a new state of charge was calculated for the battery to start the next hour of service. For example, if up regulation were selected, the resulting state of charge would be calculated as follows:

$$SOC = \frac{\left(75\% \times 8.66\,\mathrm{MW\,h} - \frac{0.5\,\mathrm{h} \times 2\,\mathrm{MW}}{\sqrt{75\%}}\right)}{8.66\,\mathrm{MW\,h}} = 61.7\%$$

Note that the usable energy capacity of 6 MW h was divided by the usable SOC range (80%) and divided by the square root of the energy efficiency to obtain the theoretical total energy capacity of 8.66 MW h. If down regulation were selected the resulting state of charge would be calculated as follows:

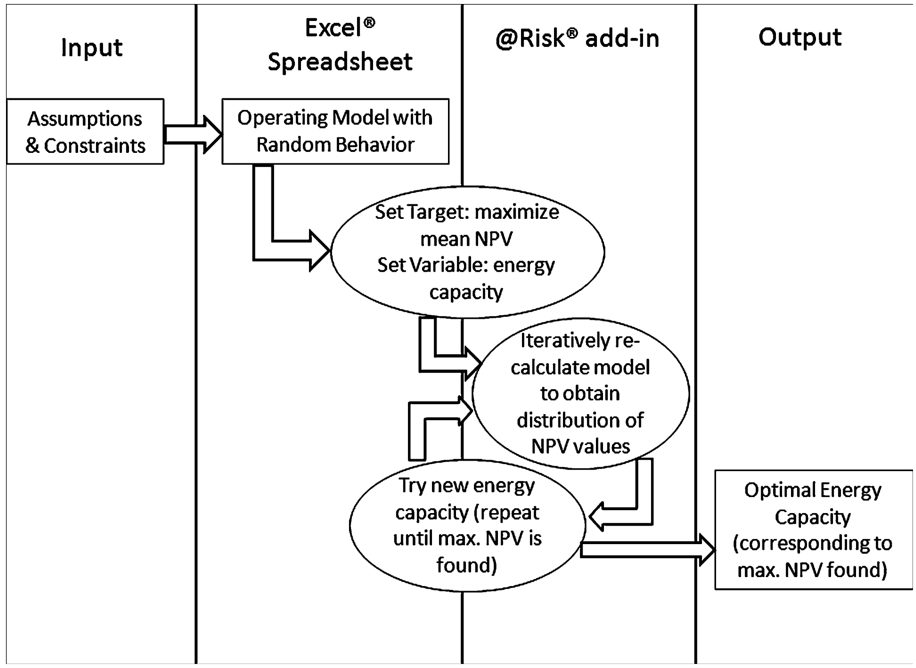

Fig. 4 Graphic representation of the simulation and optimization process used to find the optimal energy-to-power ratio of a flow battery performing an area regulation application

$$SOC = \frac{\left(75\% \times 8.66\,\mathrm{MW\,h} + 0.5\,\mathrm{h} \times 2\,\mathrm{MW} \times \sqrt{75\%}\right)}{8.66\,\mathrm{MW\,h}} = 85.0\%$$

Next, the availability of the battery for up and down regulation services for the next hour were determined. If the battery state of charge was less than the difference of the maximum SOC and 30 min worth of energy storage, then it was marked available for down regulation.

$$\text{If } SOC < \frac{\left(8.66\,\mathrm{MW\,h} \times 90\% - 0.5\,\mathrm{h} \times 2\,\mathrm{MW} \times \sqrt{75\%}\right)}{8.66\,\mathrm{MW\,h}} = 80.0\%,$$

then the battery is available for down regulation.

If the battery state of charge was greater than the sum of the minimum SOC and 30 min worth of discharged energy, then it was marked available for up regulation.

$$\text{If } SOC > \frac{\left(8.66\,\mathrm{MW\,h} \times 10\% + \frac{0.5\,\mathrm{h} \times 2\,\mathrm{MW}}{\sqrt{75\%}}\right)}{8.66\,\mathrm{MW\,h}} = 23.3\%,$$

then the battery is available for up regulation.

If the battery met both conditions then it was available for both services and received the revenue for both services.

2.3 Optimizing energy capacity

The @Risk® Excel® add-in application was used to aggregate and analyze the results of multiple operation simulations of the battery [5]. The energy capacity was specified as the variable to optimize in order to maximize the mean NPV of the project over the 10 year project lifetime. The software was set to perform as many simulations as necessary until it converged on a solution. Because of the random nature of the battery operations, each simulation required hundreds of calculated iterations in order to obtain a mean NPV. Optimal energy capacities were separately determined for storage costs of \$100, \$150, \$200, \$250, \$300, \$350, \$400, \$450, and \$500 $\mathrm{kW}^{-1}\,\mathrm{h}^{-1}$. Figure 4 shows a graphical summary of the simulation process.

3 Simulation results

The first finding from this financial simulation analysis is that an installed cost above \$500 $\mathrm{kW}^{-1}\,\mathrm{h}^{-1}$ is not likely to have a positive NPV, so that became the maximum of the range of considered installed costs. In fact, the loan interest rate would have to be lowered to 7.1% for an installed cost of \$550 $\mathrm{kW}^{-1}\,\mathrm{h}^{-1}$ to be NPV-positive. At the maximum of \$500 $\mathrm{kW}^{-1}\,\mathrm{h}^{-1}$, the simulation showed that an optimum energy-to-power ratio of 1.39 produced the maximum mean NPV value of \$16,200. For the 2 MW installation, that represents an energy capacity of 2.77 MW h. The corresponding internal rate of return (IRR) for the equity of the investment was 11%.

The resulting optimal energy-to-power ratio was the same for installed costs as low as \$300 $\mathrm{kW}^{-1}\,\mathrm{h}^{-1}$. Even as the total system size remained the same, NPV and IRR were progressively higher as the system costs decreased.

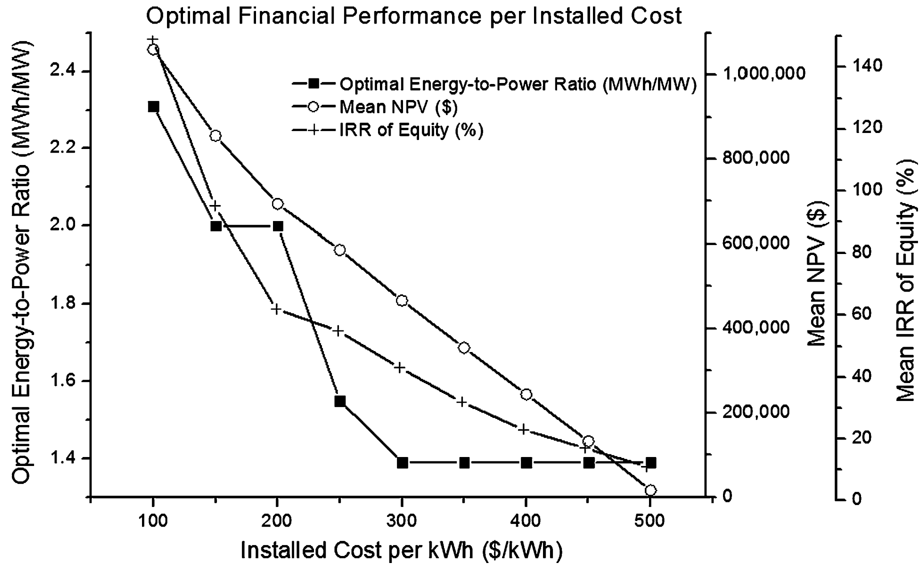

Fig. 5 The optimal energy-to-power ratio that achieves the maximum mean NPV for a range of installed system costs are shown for a battery performing an area regulation application

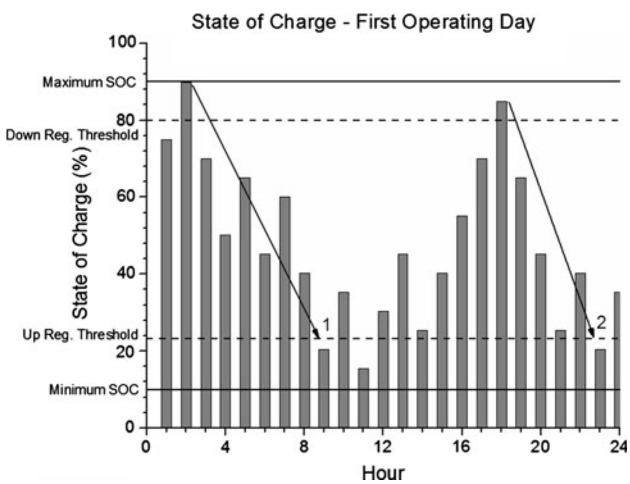

Fig. 6 SOC is shown for the first 24 h of simulated operation. Minimum and Maximum SOC lines are shown, along with the 23.3% threshold required to provide up regulation and the 80.0% threshold to provide down regulation. *Arrows 1* and *2* represent how changes from high SOC to low SOC were counted

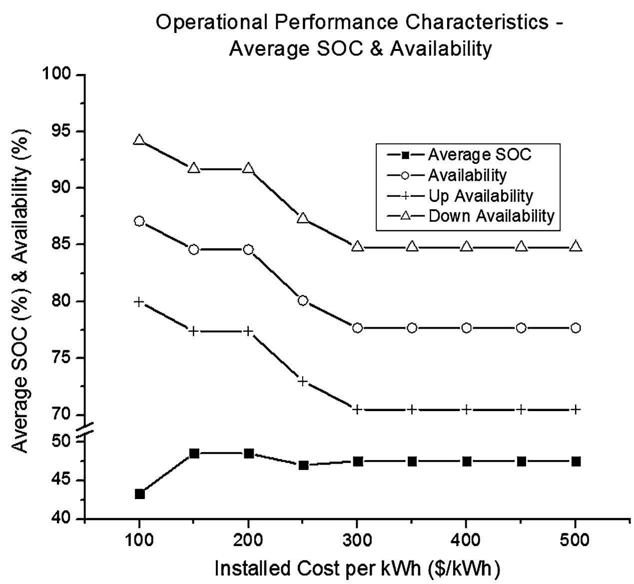

Fig. 7 The average state of charge and availability for area regulation services for a range of installed system costs are shown for a battery performing an area regulation application

At a cost of \$300 kW^{-1} h^{-1}, the mean NPV was \$466,700 with a mean IRR of 43%.

When installed costs decreased to \$250 kW^{-1} h^{-1}, the optimum energy-to-power ratio rose slightly to 1.55, with a mean NPV of \$586,300 and mean IRR of 55%. At this price point, the installed cost overcomes the costs associated with the energy efficiency losses during operation. This became even more apparent at a price point of \$200 kW^{-1} h^{-1}, where the optimal energy-to-power ratio was 2.00 with a mean NPV of \$693,700 and mean IRR of 62%. The same optimum energy-to-power ratio of 2.00 was determined for a price point of \$150 kW^{-1} h^{-1}, with a mean NPV of \$855,200 and mean IRR of 95%.

At the lowest considered installed cost of \$100 kW^{-1} h^{-1}, the optimum energy-to-power ratio again rose slightly to 2.31, with a mean NPV of \$1,060,200 and mean IRR of 149%. Figure 5 shows the optimal energy-to-power ratios, mean NPV values, and mean IRR values for the range of installation costs.

In addition to financial analysis, several operational indicators were calculated in the simulations. For all installed costs, the average SOC throughout the year of

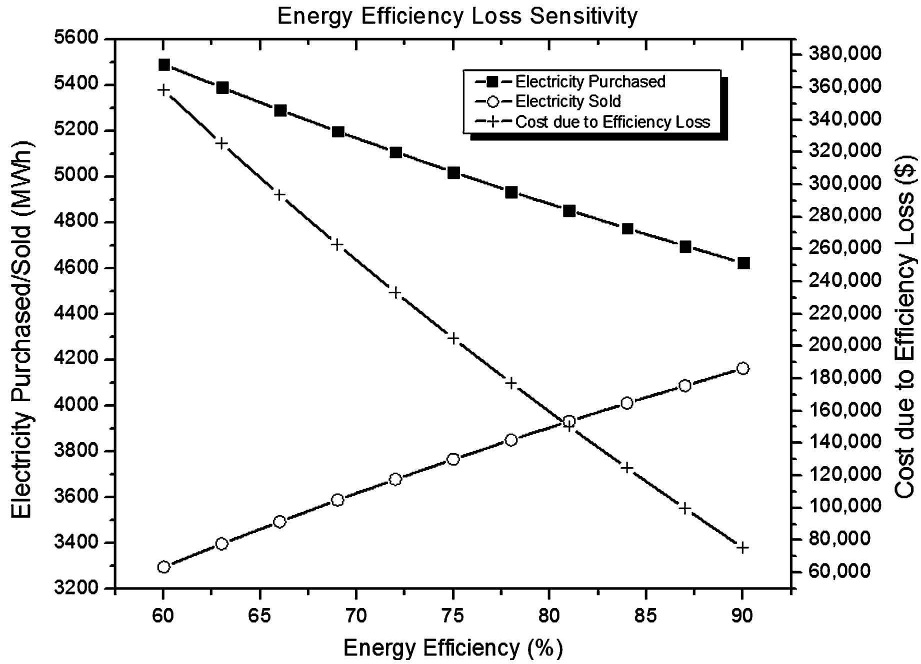

Fig. 8 Sensitivity of the amount of electricity purchased and sold while providing area regulation services, along with the resulting cost due to efficiency losses, for a range of energy efficiency values

operation ranged from 43 to 49%. For the 2.77 MW h battery, the percent change in SOC was summed for each hour and divided by two, resulting in 1087 annual round-trip cycles. Over the course of a 10 year life, this represents over 10,000 cycles, indicating the importance of using electrolytes that are resistant to degradation. In addition, the battery fell below the 23.3% SOC threshold for providing up regulation 1098 h of the year, or approximately 13% of the time. The battery rose above the 80.0% SOC threshold for providing down regulation 706 h of the year, or about 8% of the time. The battery SOC dropped from above the higher threshold to below the lower threshold a total of 366 times per year. Figure 6 shows sample states of charge for the first 24 h of simulated operation. The arrows in the graph are examples of how the changes from the upper threshold to the lower threshold were counted. Deep discharges such as these are often detrimental to battery cycle life for many systems such as lead-acid and lithium–ion, but not so much for flow battery types.

As the system cost decreased below \$300 kW^{-1} h^{-1}, the corresponding energy capacity of the system increased, and the availability to perform area regulation services also increased. For the lower energy-to-power ratios, and costs above \$300 kW^{-1} h^{-1}, the battery was available for an average of 78% of the hours in a year (71% availability for up regulation and 85% availability for down regulation). For an optimum energy-to-power ratio of 1.55 (corresponding to a cost of \$250 kW^{-1} h^{-1}), the average regulation availability increased to 80% (73% availability for up regulation and 87% availability for down regulation). As the optimum energy-to-power ratio increased to 2.00 (corresponding to installed costs of \$200 and \$150 kW^{-1} h^{-1}), the average regulation availability increased further to 85% (77% availability for up regulation and 92% availability for down regulation). The average SOC and percent availability (for up, down, and average regulation services) are shown for the range of installed costs in Fig. 7.

For all simulations, the annual amount of electricity purchased from the grid when providing down regulation was 5,019 MW h. The annual amount of electricity sold back to the grid when providing up regulation was 3,765 MW h. This resulted in a net annual cost due to efficiency losses of \$204,800. This lost revenue is directly related to the efficiency of the battery. As the efficiency increased, the annual amount of electricity purchased decreased while the annual amount of electricity sold increased. Figure 8 shows this behavior for a range of round-trip energy efficiencies, using the 2.77 MW h system as the model (corresponding to a energy-to-power ratio of 1.39).

4 Candidate battery chemistries

Several battery chemistries for redox and hybrid flow batteries for this application have been examined. A recent summary of flow battery technology and the various electrolytes are presented by Nguyen and Savinell [6]. A majority of these systems are still being developed. The few that have advanced to limited commercialization include the all-vanadium redox, zinc-bromine hybrid, and iron-chromium redox flow batteries. Given the required

Table 1 A summary of assumptions used in the simulation of a flow battery in an area regulation application

Assumption	Value	Assumption	Value
Power capacity	2 MW	Project/battery life	10 years
Round-trip efficiency	75%	Project financing	70%
Charge/discharge time	30 min per hour	Loan term/rate	8 years @ 10%
Electricity price	\$163.3 MW^{-1} h^{-1}	Maintenance cost	\$8 MW^{-1} h^{-1}
SOC range	10–90%	Income tax rate	25%
Price escalation	2.5%	Depreciation rate	10%

Table 2 A summary of financial and operational simulation results

Installation cost (kW^{-1} h^{-1})	Optimal energy-to-power ratio	Mean NPV	Mean IRR (equity) (%)	Average SOC (%)	Up availability (%)	Down availability (%)
\$100	2.31	\$1,060,200	149	43.3	80.0	94.2
\$150	2.00	\$855,200	95	48.5	77.4	91.7
\$200	2.00	\$693,700	62	48.5	77.4	91.7
\$250	1.55	\$586,300	55	47.0	73.0	87.3
\$300	1.39	\$466,700	43	47.5	70.5	84.8
\$350	1.39	\$354,800	32	47.5	70.5	84.8
\$400	1.39	\$244,200	23	47.5	70.5	84.8
\$450	1.39	\$132,600	17	47.5	70.5	84.8
\$500	1.39	\$16,200	11	47.5	70.5	84.8

energy-to-power ratios for the area regulation application are relatively small any of the battery types would be technically able to provide the necessary energy and power. The primary consideration beyond that is cost, but SOC range and cycle life are also considerations of importance. Both the deep cycling and high number of cycles in area regulation are beyond the usual performance scope of typical lead-acid batteries [7]. The deep cycling and long cycle life typical of flow batteries are better suited to these requirements and were examined further.

The all-vanadium redox battery is unlikely to be able to achieve a cost below \$500 kW^{-1} h^{-1} in the near future. Several studies have been conducted on the costs of vanadium redox systems, with commensurate variability of results. One detailed cost estimate has shown that a hypothetical vanadium redox battery could be manufactured for as little as €100 kW^{-1} h^{-1} (\$135 kW^{-1} h^{-1}) for an energy-to-power ratio of 150 [8]. However, similar low costs have not been demonstrated with smaller energy-to-power ratios. A project is currently underway in Painesville, Ohio to install a 1 MW, 8 MW h demonstration vanadium redox flow battery by 2014, with a projected budget of \$7.49 Million [9]. At the energy-to-power ratio of 8 (low for this type of system, but high for area regulation), the cost will be at least \$936 kW^{-1} h^{-1}. A 2008 report by Sandia National Laboratories estimates the cost of vanadium redox flow batteries at \$600 kW^{-1} h^{-1}, with projected future costs at \$500 kW^{-1} h^{-1} [10]. Since lower costs are generally achieved with higher energy-to-power ratios, low costs are very unlikely to be realized in the small energy-to-power ratios needed for area regulation.

Zinc-Bromine hybrid flow batteries may be closer to a feasible cost target. According to the investor presentation of ZBB Energy published on their website, the current production cost of their product is about \$800 kW^{-1} h^{-1}. The next version of their product, to be produced starting in 2011, is claimed to have a lower cost of \$400 kW^{-1} h^{-1} [11]. For a larger grid-scale production, they claim to be able to produce a solution for a little over \$100 kW^{-1} h^{-1}. Further, the zinc-bromine battery is limited to an energy-to-power ratio of about two due to plating density constraints of the zinc. This limit fits well with the lower energy-to-power ratios required for area regulation. The 2008 Sandia National Laboratories report estimates the current cost of zinc-bromine flow batteries at \$500 kW^{-1} h^{-1}, with future costs of \$250 kW^{-1} h^{-1} plus \$300 kW^{-1} h^{-1}—for a 2 MW, 2.77 MW h battery this would be \$467 kW^{-1} h^{-1} [10].

Current production costs of iron-chromium flow batteries are not well-documented in published literature. However, the relatively lower cost of these metals compared to vanadium could lead one to speculate that lower electrolyte and overall system costs could be achieved. Indeed, a 2008 NASA article states that current versions of commercial iron chromium flow battery systems are "effectively three times less expensive than lead-acid batteries” [12]. While the exact meaning of this is unknown, Sandia scientists estimate the price of traditional lead-acid batteries to be \$150 kW^{-1} h^{-1}, well within the cost range necessary to be profitable in an area regulation application [10].

Other battery chemistry candidates may include the little-studied all-iron hybrid flow battery and the hydrogen-bromine flow battery. Performance of an all-iron hybrid flow battery has been briefly studied, but no further research has been published [13]. The abundant and low-cost features of iron could significantly decrease the cost of electrolyte in such a system. A combined public and private research team assembled by Lawrence Berkeley National Laboratories is currently investigating the commercialization of hydrogen bromine flow batteries, and estimates that at full commercialization costs could go well below \$100 kW^{-1} h^{-1} [14].

5 Summary and conclusions

A 2 MW flow battery was simulated in an area regulation application, with the goal of optimizing the energy-to-power ratio for maximizing the net present value of a 10 year project. Several assumptions, summarized in Table 1, were input into the simulation.

Using these assumptions, it was determined that profitable battery system operations require an installation cost of \$500 kW^{-1} h^{-1} or less. Projects with installation costs ranging between \$100 and \$500 kW^{-1} h^{-1} were simulated. The results of these simulations are summarized in Table 2.

The cost (lost revenue) due to efficiency losses, caused by the difference between the amount of energy purchased and sold during the year, was shown to be directly related to the energy efficiency of the battery, with higher efficiencies correlating with lower costs. With an efficiency of 75% and an energy-to-power ratio of 1.39, the simulated battery was shown to have cost (lost revenue) due to efficiency losses of \$204,800.

Candidate flow battery chemistries were discussed that may best fulfill the financial requirements of such a project. One of the oft-cited advantages of the redox flow battery is the ability to decouple power and energy capacities. Lower costs per-kW h can generally be achieved as energy-to-power ratios increase. This decoupling advantage would not be fully realized in this application, given the relatively small optimum energy-to-power ratios for the area regulation application. Hybrid flow batteries, which have limits on energy-power ratio due to plating density or reaction surface area limitations may be more appropriate for area regulation.

The newest large-scale commercial versions of zinc bromine flow batteries might provide low enough cost, while iron chromium battery costs are less well-known but likely fall within the required cost range. In the future, all-iron or hydrogen-bromine flow batteries may provide lower cost solutions for this application.

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