Case Study

Exploring the Multifaceted Role of Pumped Storage at Niagara

Samiha Tahseen, S.M.ASCE[1]; and Bryan W. Karney, P.E., M.ASCE[2]

Abstract: Energy systems are not only intrinsically interesting, because power is itself of importance; they raise fascinating trade-offs in other areas particularly since there are almost invariably technical, economic, and ecological dimensions to these considerations. This paper illustrates this interplay through a staged process that starts with a direct optimization approach for a pumped-storage facility with the simple goal of achieving an optimal profit given well-forecasted flows and energy prices. Sir Adam Beck Pumping Generating Station, located on the Niagara River, is selected as the subject of the model application. When analyzed for probable changes in current electricity rates, a 1–24% reduction in profit is realized depending on the month. Interestingly, relative to current design the model predicts only modest profit throughout the year with an increasing reservoir footprint. Since considerations other than the purely technical quickly arise, this paper considers the trade-off between hydropower and ecological targets imposed by the 1950 Niagara River Treaty. This exploratory study makes no pretense to forecast likely or advisable developments, but rather considers a possible role that a pumped-storage operation might hypothetically play in the Ontario spot market. **DOI: 10.1061/(ASCE)WR.1943-5452.0000666.** *© 2016 American Society of Civil Engineers.*

Background

Despite its typically high development costs and sometimes considerable environmental impacts, hydropower has much to recommend it. Once installed, it has a desirable quick-start and black-start capability (Evans et al. 2009; Sharma et al. 2015). It can efficiently respond to peak load (Maxim 2014), its spinning reserve provides flexibility and protection to the overall grid (Zhang et al. 2015), and it allows leveraged investments in other intermittent sources (Ayodele and Ogunjuyigbe 2015). Because its raw power comes from a renewable source, hydro is able to reduce the electrical system's reliance on fossil fuel. Pumped-storage hydroelectricity (PSH) enhances power generation in that water can be pumped to a higher-elevation reservoir and stored in the form of gravitational potential energy. Pumps are predominately run using low-cost off-peak electricity, and the stored water later generates electricity at peak price, usually during periods of high demand. Although the energy losses of the pumping process make the plant a net energy consumer (IPCC 2011), the system often increases revenue by selling high and buying low and thus helping to balance the grid.

At present hydropower is experiencing a worldwide renaissance. The need for clean, affordable energy and the increasing need to have a flexibility component in the supply mix have driven interest in hydroelectricity. Canada is the world's third-largest hydropower producer with 9.8% of total production, according to the *BP Statistical Review of World Energy* (British Petroleum Company 2015). In 2014 hydropower generation in Ontario alone exceeded 37 TWh (IESO 2015). The Niagara River, along with its contribution to the tourism sector, acts as a key resource to this generation. Presently river power provides nearly 8% of Ontario's total electricity generated at the Sir Adam Beck (SAB) complex. Along with two conventional power stations, the complex currently hosts Ontario's only pumped-storage station, the SAB Pumping Generation Station (PGS). With its limited capacity, PGS contributes to stabilizing the grid by producing power on demand and also by storing surplus energy generated by nondispatchable and intermittent sources. The SAB PGS's ability to pump water is fundamental to water level control at the point of crossover, a critical component in ensuring appropriate performance (Maricic et al. 2009). One of the roles of the plant is a little unconventional; that is, it is intended to store a volume of water nearer to the two conventional hydro plants, thus enhancing their hydraulic capacity to improve their responsiveness to peak power demands (Fig. 1).

Being the only commercially proven utility-scale energy storage technology, PSH has been suggested as a key response to demand variability (Rehman et al. 2015). However, despite perceived technical demand, profitability remains a major obstacle for PSH systems. Ingebretsen and Johansen (2014) assessed six proposed PHSs in Norway and rejected the profitability of all of them. However, this outcome contrasts with a report by the German Advisory Council (2011), which suggested that those plants have a high return on investment. A comprehensive cost-benefit model by Zafirakis et al. (2013) shows that both pumped hydro and compressed air energy storage (CAES) can be cost-effective with the application of a "socially just" feed-in tariff (FIT). Such a prognosis is interesting since PGS, being a relatively well-known option, is not eligible for FIT rates in Ontario. Salevid (2013) investigated the economic viability of restoring a currently decommissioned Swedish pumped storage and established a correlation between price volatility (energy price variability during on-peak and off-peak hours) and PSH profitability, concluding that the feasibility of PSH depends on sustained highly volatile energy prices. The SAB PGS faces similar challenges, with the unit energy cost increasing by 72% between 2006 and 2008 (from \$47.1 to \$81.2/MWh) (Ontario Power Generation 2010). The Ontario FIT Program,

[1]Ph.D. Candidate, Dept. of Civil Engineering, Univ. of Toronto, Toronto, ON, Canada M5S 1A4 (corresponding author). E-mail: samiha.tahseen@mail.utoronto.ca

[2]Professor, Dept. of Civil Engineering; Associate Dean, Cross-Disciplinary Programs; Chair, Division of Environmental Engineering and Energy Systems, Univ. of Toronto, Toronto, ON, Canada M5S 1A4. E-mail: karney@ecf.utoronto.ca

Note. This manuscript was submitted on October 14, 2015; approved on February 4, 2016; published online on June 13, 2016. Discussion period open until November 13, 2016; separate discussions must be submitted for individual papers. This paper is part of the ***Journal of Water Resources Planning and Management***, © ASCE, ISSN 0733-9496.

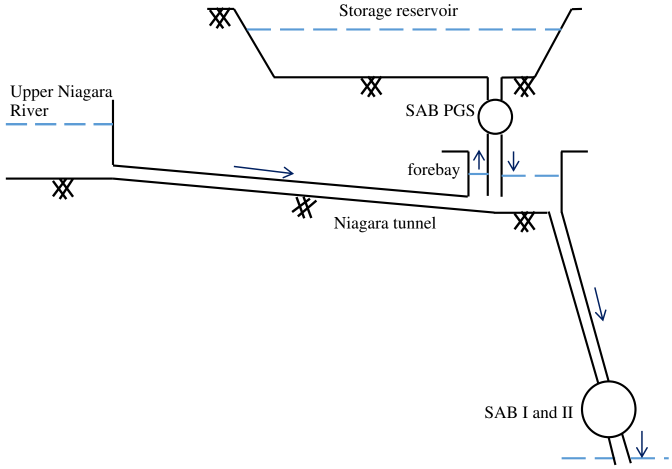

Fig. 1. Niagara hydroelectric plants system (© 2009 IEEE. Reprinted, with permission, from Maricic et al. 2009)

expecting to quadruple wind capacity by 2018, can impact PGS in two ways—increased availability of low-cost, off-peak electricity to reduce pumping cost and low electricity prices to decrease the overall profit opportunity (Linares et al. 2008).

Economic viability is a major consideration for any development and perhaps the strongest motivation of investors. Deregulation of the electricity market has created a competitive, profit-driven environment in which hydro producers, whose typical role was to balance the grid, face new challenges with the ultimate goal of maximizing profits. With the development in storage technologies such as flywheels, CAES, batteries, capacitors, and so forth, there is a need to assess the role of PSH as most likely to be a cost-effective storage option. Rangoni (2012) suggested a case-by-case analysis to determine the most cost-efficient solution to grid flexibility, and recommended investigating pumped-storage feasibility with respect to the market's ability to deliver profits. In this context, analyzing the profit characteristics of the SAB PGS under various energy price scenarios is worth investigating. The expiration of the original 1950 Niagara River Water Diversion Treaty, which currently dictates limits on the available water for hydropower, opens the possibility of using a greater allocation of water for power than currently allowed by the terms of the existing treaty. Hence, the current study explores what portion of the hydropower potential is compromised by the current terms of the treaty and the possibility of increased generation through renegotiation. To analyze fully the role of Niagara's potential PGS contribution in meeting peak demands is outside the current scope of this research.

The idea of prescheduling pumping and generation using forecasted data on demand and subsequent price is not new. Afshar (2012) and Bosona and Gebresenbet (2010) developed optimization models for maximizing hydropower generation where the monthly values of the key decision variables are generated for a year. However, aggregating the results on a monthly basis may not be realistic because such coarse resolution aggregation fails to capture the impact of changes in demand and price due to seasonal variations, long holidays, sudden weather changes, and interruptions to the power supply. Moreover, although most reservoirs tend to be used for seasonal water storage, typical pumped storages are used for load leveling purposes. Thus, its operation typically involves daily filling and subsequently discharging water. Given this, a model that optimizes decision variables on a monthly basis holds few advantages over typical operational models. In contrast, short-term models give more control over time, duration, and flow to maximize the performance of PSH generators. Realizing this, Latorre et al. (2014), Mo et al. (2013), and Prasad et al. (2012) proposed short-term hydro scheduling and discussed its challenges and possible solutions. Considering the availability of reasonably accurate day-ahead energy price–forecasting models (Aggarwal et al. 2008; Zareipour et al. 2006), the work described in this paper can be used to optimize the daily operation schedule for maximizing benefits. The developed model is then used for extensive analysis of profit characteristics, the impact of potential constraints in the form of the 1950 treaty, and possible improvements by varying cycle length and reservoir size.

Brief Literature Review

In conventional hydropower optimization models, the objective function is nonlinear because the product of the discharge and the head are required for decision making. Hydropower capacity of a storage plant can be expressed as

$$P = \eta\rho g Q(t)H_n(t) = KQ(t)H_n(t) \tag{1}$$

where $K = \eta\rho g$; K = constant; η = overall efficiency to produce hydropower; ρ = water density; g = gravitational acceleration; and Q = water release for power generation. The net head can be written as

$$H_n = H - H_{\text{tail}} - H_{\text{loss}} \tag{2}$$

where H = storage water level; H_{tail} = tail water level; and H_{loss} = head loss at time t. If changes in H_{tail} and H_{loss} are insignificant compared with H, $H_n = H$ can be approximated. Then the objective function for maximizing hydropower energy can be formulated as

$$E = K\sum_{j=1}^{J} Q(j)H(j) = KQH \tag{3}$$

Yet even Eq. (3) is a nonlinear product of the vector Q and H. Successive linear programming (SLP) first appeared in Griffith and Stewart (1961). Although Palacios-Gomez et al. (1982) reported a few rather unimpressive results, this approach remains highly recommended in reservoir operations because of its easy implementation and tendency to converge to a global optimum. Further effort by Kamodkar and Regulwar (2013) applied fully fuzzy linear programming (FFLP) on a multipurpose reservoir to represent uncertainties in system parameters. Fleten and Kristoffersen (2008) proposed a mixed-integer linear programming (MILP) model and demonstrated its application with a Norwegian facility. Whereas many researchers have approached reservoir operation through successful linearization of the objective function, Helset et al. (2013) and Moeini et al. (2011), proposed a model based on stochastic dynamic programming (SDP). Haguma et al. (2010) added consideration of climate-induced flow variation whereas Catalão et al. (2012) used nonlinear programming (NLP) for optimizing hydropower generation. Clearly there is no general algorithm but rather a range of choices depending on reservoir-specific system characteristics and the preferences of the modeler.

This study introduces a rather straightforward MILP model to investigate pumped-storage profitability at the SAB PGS. The model evaluates a daily operation schedule (pumping and generation) to assess the available energy that can be offered on the market and at the same time reduce cost associated with pumping operations. The objective is to examine the impact of changing electricity rates, reservoir capacity, and treaty flow constraints on PGS profitability. The exploratory nature of the study motivates the adoption of a simplified LP approach, rather than a more complex nonlinear or dynamic programming approach. Kusakana (2015) studied the technoeconomic feasibility of pumped storage and recommended it in conjunction with a stand-alone hydrokinetic system. Similar studies by Caralis et al. (2012) and Steffen (2012) investigated the potential of pumped hydro storage systems with increasing penetration of renewable resources. This paper analyzes the role of PGS from an economic perspective and includes a trade-off analysis between financial and environmental considerations. It further explores the benefits and possible challenges faced by PSH development in Ontario.

Optimization Model Development

Based on the approaches discussed, the authors adopted a linearized optimization model for the SAB PGS. The following sections discuss the model and the data used for the purpose.

Formulating the Context-Specific Optimization Model

In Canada, regulatory and policy control over the electricity industry is primarily vested with the provinces. The electricity system in Ontario is a hybrid between a market and a regulated entity where generators submitting bids to the system operator are dispatched from the lowest bid until the demand is satisfied (IESO 2015). Lately the annual demand curve has exhibited a dual peak (summer and winter), where the highest-demand situations usually occur during the summer (IESO 2015). The hourly average of the 5-min energy market clearing price (MCP) is defined as the hourly Ontario energy price (HOEP), and forms the basis for financial settlements. As intermittent renewables are offered a guaranteed price through the FIT program, HOEP bears little to no relation to the cost of building renewable capacity (Auditor General of Ontario 2011).

Because PSH benefits from price arbitrage, selection of pumping and generation durations is critical for optimizing SAB PGS operation. Decision variables representing pumping and generating hours (x, y) are required to be dichotomous. In the model, these variables adopt a value of 0 or 1 for nonoperating/operating stages. No time delay is considered for the transition from the pumping to the generating sequence as suggested by Maricic et al. (2009). The model contains another set of variables (u, v) representing inflow into the reservoir and outflow through the turbines. Dispatchable sources such as the SAB PGS are primarily aimed at providing ancillary services and are online when nondispatchable (nuclear) and intermittent sources (wind and solar) are exhausted. Therefore, analyzing PGS's contribution to peak power requires estimating residual demand—generations from all nondispatchable and intermittent sources throughout the province subtracted from total demand. Because of the resource-intensive nature of data collection and processing required for such calculation, the hourly Ontario energy price (HOEP) is used as a suitable surrogate in the current model. There remains a strong, positive, and statistically significant correlation ($r = 0.6$, $P < 0.001$) between demand and HOEP, suggesting that a 36% variation in demand data can be explained by energy price, so the approximation is reasonable given the exploratory purpose of this research. Such an approximation permits reasonable estimation of profit for the facility. Now, in combination with an electricity price–forecasting model, pumping and generating hours and the corresponding flows for the SAB PGS can be determined.

To represent the volume of water stored in the reservoir at start of hour i, the authors introduce a storage function S and assume it to be empty (0) at the beginning of the operation. The model operates to exhaust all the water stored within the same day. The upstream river flow is computed using a United States Geological Survey (USGS) rating curve on 1-h water level data from National Oceanic and Atmospheric Administration (NOAA 2013) Station 9063020, located at the mouth of the Niagara River. Water level data from 2007 to 2013, obtained in units of feet, are converted to discharge (Q, cfs) using the following rating equation:

$$Q = 260.5(H - 550.11)^{2.2} \tag{4}$$

where H = water level above IGLD1985 i.e., the international elevation reference for the Great Lakes-St. Lawrence river system.

The historical flow data is then averaged to get a reasonable estimation of the hourly river flow. The possibility of considerably large flow variations is ignored because of the highly regulated nature of the upper Great Lakes. Not all of this water can be used for hydropower generation because the power flow is subjected to the 1950 Treaty restrictions which establish that during the period lasting from April 1 to September 15, no less than 2,832 m^3/s (100,000 cfs) must be going over the falls between 8:00 AM and 10:00 PM. The same flow restrictions are effective between 8:00 AM and 8:00 PM from September 16 to October 31. At all other times, a minimum of 1,416 m^3/s (50,000 cfs) should be maintained unless additional water is necessary (Government of Canada 2015). Fig. 2 shows the flow-handling capacity at the SAB complex in comparison with the daily variation in available power flow during representative months. The restrictions, which coincide with peak electricity demand in Ontario, limit generation because the available power flow can at times be half of the SAB's maximum capacity. Now, the flow at the SAB PGS is calculated by deducting the discharge required for reasonable generation (75% capacity) at the two conventional power plants (SAB I and II) from Canada's share of the treaty-specified available water. Note that the available flow at the SAB complex is further limited by the diversion capacity of the existing tunnels and the power canal—the impact of which is ignored considering the scope and exploratory nature of this study.

The mathematical expression for the model is as follows:

1. Objective function:

$$\max \sum_i y_i r_i v_i - \sum_i x_i c_i u_i \tag{5}$$

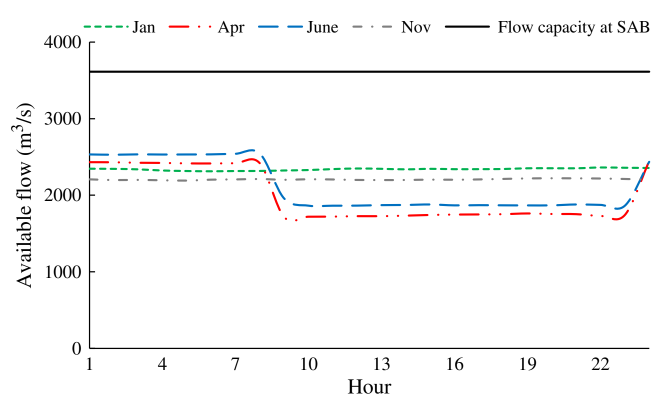

Fig. 2. Comparison between available power flow and maximum capacity at the SAB complex

where r_i = revenue generated from turbine release; c_i = cost incurred from pumping; u_i = volume of water pumped; and v_i = release through the turbine. Decision variables x_i and y_i represent the decision to operate the pump and turbine at the ith hour, respectively. Here, $i = 1, 2, 3, \ldots, 24$.

2. Constraints: The model must reflect a rather long list of constraints to replicate the existing system at the SAB PGS. Beginning with typical reservoir constraints such as capacity, flow balance, and the like, the list extends to limits that are specific to the system at Niagara. One such limit, the dichotomous nature of pumping and generation functions, requires a constraint that ensures that only one of the operations is running at a time, as represented by Eq. (6):

$$x_i + y_i \leq 1 \tag{6}$$

System-specific constraints such as maximum flow-handling capacity of the installed pump and turbines are incorporated into the model. Another standard constraint in reservoir operation is the dependency of release on just-in-time storage. The last constraint built into the model is the flow restrictions imposed by the 1950 Niagara River Treaty followed by non-negativity constraints. A complete list of constraints along with the mathematical expressions are provided in the Appendix.

Analyzing Input Price Data

For computing the cost and revenue component of the model, the authors use 2003–2012 HOEP data from the Independent Electricity System Operator (IESO 2015). These data are analyzed to create four scenarios: (1) characteristic period in terms of peak demand, (2) possible electricity price fluctuation for each month, (3) price variations on the basis of weekday or holiday, and (4) increase in storage. For this purpose, the daily average electricity price is computed and this data set was used to determine the 85th and 15th percentile average HOEP. A random selection is made from the days with average HOEP above the 85th percentile value for extracting the hourly rate from the original data set for each month. This procedure is repeated for the data set below the 15th percentile value. These two separate energy price information for each month, extracted from the 85th- and 15th-percentile data sets, represent the high and low energy price, respectively, throughout this paper. Such a procedure examines the impact of price volatility for two extreme cases in each month so that the result is a range rather an exact number for profit. To investigate the effect of weekday/holiday energy price variation on scheduling, the authors follow the same procedure described previously; however, the percentile is now computed on data separated on the basis of weekday and holiday. Thus, each month is associated with four different energy price data sets: weekday high HOEP, weekday low HOEP, holiday high HOEP, and holiday low HOEP.

Based on the occurrence of consistently high energy prices, months with typically high electricity demand are selected. The data is further analyzed for months with a large spread in energy price data, which is captured by standard deviation. Such analysis is interesting because large fluctuations in price provide room to increase profits by reducing costs associated with pumping, at the same time maximizing revenue from generation. The authors then convert these data to price per unit volume of water based on the operating conditions of the SAB PGS. Although the difference in head between the upper and lower reservoir ultimately affects the potential energy of the stored water, tracking the exact difference is awkward (Chang et al. 2013); thus, a fixed head is used to ensure a representative price per unit volume of water. A relatively low pumped-storage efficiency (50%) is used to compensate for such approximation.

Model Explorations

The developed model allows several characteristic of the SAB PGS to be explored, such as daily price variation for pumping and generating decisions, profit characteristics for weekdays and holidays, profit sensitivity to cycle length, and so forth.

Analysis of Profit Characteristics on a Monthly Basis

The task of choosing pumping, generating hours, and corresponding flows that best utilize the price variation scheme is accomplished by the proposed model. Analysis suggests that, for taking full advantage of a time-sensitive price scheme, the facility must focus on small-scale price variations within a day for pumping and generating decisions.

August has the best scope of increased revenue generation. A typical day in this month can earn an average profit of just over C$17,500 when allowed to run on full capacity, leading to a total of approximately C$543,000 per month. However, the flow constraint imposed by the treaty restricts the available flow for pumping. When incorporated into the model, it results in a reduced profit of C$10,700 per day, leading to a substantial C$211,000 decrease in monthly profit. The same holds true for the month of February, which is found to have the least profit-yielding month according to the proposed model. Notably, certain days in February provide no incentive for operating the reservoir from a financial return perspective. The wide disparity in daily profit with the high and low energy price scenario for the same month indicates a highly volatile electricity market in Ontario. This finding is consistent with Zareipour et al. (2007), who identified the provincial electricity market to be one of the most volatile after comparing with similar markets worldwide.

When analyzed for the factors responsible for profit variation, both the average and the median HOEP for February and August are found to be strikingly similar. The reason for the difference in monthly profit lies in the interquartile range, which for August offers a greater scope for optimization than February. The results obtained when running the model with the high and low electricity price data set for each month are then averaged and aggregated to obtain the monthly profit, as shown in Fig. 3. In a comparison of annual income with and without the treaty flow restriction, the compromised hydropower potential is found to be worth just over C$6 million. The logic behind such aggregation is that the analysis here aims to provide a ballpark estimate rather than a precise number. Since the profit relies on electricity rate, which varies widely (C$−10 to over $200/MWh) owing to hourly demand and supply (IESO 2015), there is little value for such exact estimation.

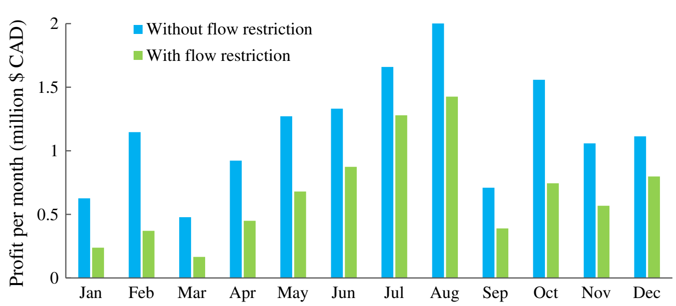

Fig. 3. Estimation of monthly profit with and without flow restriction

Analysis of Profit Characteristics on a Weekday/Holiday Basis

High and low energy price data separated on the basis of working days are used as input to the model to evaluate profit sensitivity to these factors. The model predicts a reasonably higher profit during weekdays than during weekends (Fig. 4). According to this revenue model, persistent low electricity rates during the weekends of January and February promote little economic gain for PGS operation. Another distinctive pattern is the reduced profit during the weekends of May, June, and July, considering the typically high demands during these summer months. This can attributed to either generally high prices with little variation over a 24-h period, leading to little difference between the revenue and the pumping cost, or increased outdoor activities that drive down both demand and price. The latter case represents situations where the diurnal-scale pumped-storage contribution may be redundant; thus, the proposed model responds by reducing generation. The result reinforces the need for price volatility on a 24-h basis for pumped-storage feasibility.

Profit Sensitivity to Cycle Length

Because the change from pump to turbine operation (and vice versa) is achieved within a few minutes (Maricic et al. 2009), the model assumes a seamless transition between these cycles. Frequent changes in operating conditions are relatively common for pumps, but this is not usual practice in the case of turbines. Often these transitions are associated with vibrations and wear in the system that lead to machine depreciation. Fig. 5 compares average monthly profit for three different cycle lengths. Although the model yields a significantly higher economic gain for the 1-h cycle, the difference in profit between the 2- and 3-h cycles is negligible. Based on the results, the 1-h cycle may be chosen as an attractive alternative from the single perspective of profit maximization. However, a 3-h cycle is preferred over a 2-h cycle in terms of both maximizing economic gain and protecting the structural integrity of the current system.

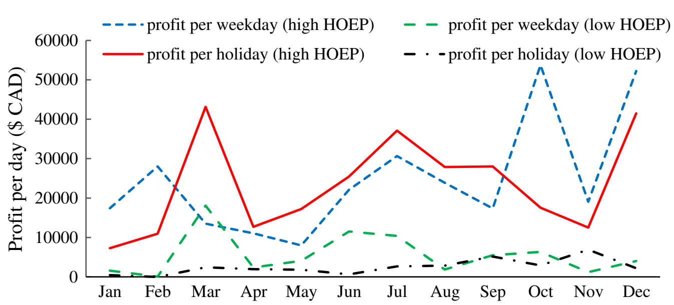

Fig. 4. Profit variation during weekdays and holidays

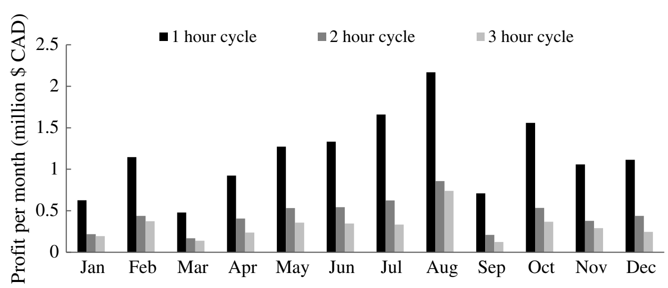

Fig. 5. Comparative analysis of economic return versus running time

Evaluating Potential Improvement Opportunities for the SAB PGS

The third Niagara tunnel, completed in 2013 for C$1.6 billion, increases Canada's diversion capacity by 500 m^3/s. With the tunnel in place, the PGS expansion plan now includes increasing the reservoir footprint by raising the dyke elevation. The model assumes a 4-m increase in reservoir height leading to a storage capacity of 32 Mm^3 (instead of the current 20 Mm^3). Analysis shows no economic gain with such an increase in reservoir capacity. With the flow restriction in place (and 75% generation at SAB I and SAB II), the SAB PGS simply will not be able to utilize the excess capacity offered by the increased reservoir footprint. Moreover, the scheme does not guarantee higher profit throughout the year even when operated with a no-treaty restriction model. The hours with the best profit opportunity having already been selected, the additional storage allows operation only during periods that offer little difference between revenue and pumping cost. The outcome shows additional revenue for months with relatively high electricity price variation without any noticeable increase in revenue for the rest of the year.

Profit Sensitivity to Energy Price

The analysis has heretofore explored pumped hydro operation based on historical electricity rates. However, increased participation of pumped storage has the potential to influence the electricity market. In Ontario the HOEP results from generators submitting bids to the Independent Energy System Operator (IESO), which dispatches generators starting with the lowest bid. When the system is congested, some higher-cost units may be necessary to release congestion. Pumped hydro, because of its operational flexibility, can alter the electricity spot price by delaying the participation of such higher-cost units (Kanakasabapathy 2013). Depending on operational mode, pumped hydro can influence energy price in two ways. First, in pumping periods the pumped hydro consumes electricity and therefore HOEP may rise. Second, when the same facility generates, the marginal cost decreases (Sousa et al. 2014). Research shows that the impacts of spinning reserve on hourly spot prices can be as large as 25% (Zhu et al. 2000). Considering the limited pumped-storage capacity (174 MW) in Ontario, the analysis here assumes a 2.5–10% reduction in electricity rates during the peak demand hours (9 to 15-h and 18 to 21-h). Because of the surplus generation from wind resources in Ontario (Gallant 2015), this study ignores the impact of nighttime pumping operation on energy price.

The model generated is next used for evaluating the impact of changing energy price on PGS profit characteristics (Fig. 6).

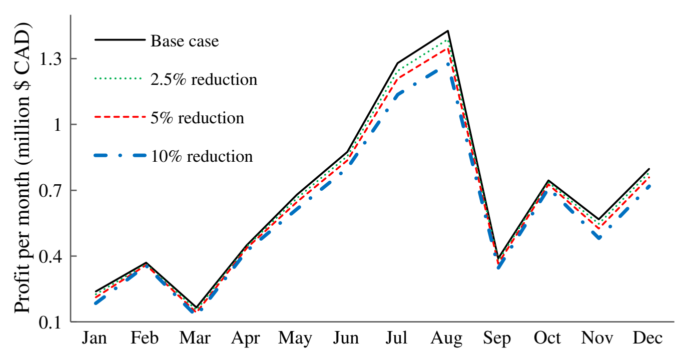

Fig. 6. Impact of changing electricity rates on pumped-storage profit

According to the analysis, the changing electricity rate due to increased grid participation by the SAB PGS can result in a 1–24% reduction in profit depending on particular months. The relatively large reduction is more consistent in winter months when the energy price is generally low.

Trade-Offs between Power Generation and Scenic Flow Restrictions

Almost all real decision-making problems are multiobjective. These problems often involve trade-offs among conflicting objectives. For PGS, which serves hydropower generation as a key purpose, the operator may wish to maximize power generation while adhering to the flow restrictions imposed by the 1950 Treaty. However, these two objectives are typically conflicting because the treaty restrictions, which specify a minimum flow over the Niagara Falls, also limit the available flow. For this reason, the authors use the Constraint Method, which transforms multidimensional problem into a series of one-dimensional problems. The technique involves optimizing one objective while representing other objectives as constraints. Systematic repetition with different constraints on the objectives generates the entire set of noninferior solutions (Neufville 1990). The trade-off curve, often called a Pareto surface, elucidates the degree of sacrifice of one benefit required for gain of another.

Here, generating profit for PGS is maximized and available pumping flow is constrained over a range of target values. Fig. 7 shows the resulting Pareto surface for July where Point A represents the greatest possible profit with no flow restrictions and Point B represents profit under current constraints. July is ideal for the trade-off analysis because the tourist flow requirement coincides with high power demand. Whereas Points A and B are two major alternatives, Point C, with a 708-m^3/s reduction in tourist flow, represents a compromise solution that results in a 2.3% increase in profit. An additional 2% increase occurs when the entire tourist flow (which still maintains 1,416 m^3/s over the falls) is diverted for power generation purposes (Point D). The profit is subjected to an increasing growth rate between Points A and D, which suggests a stronger conflict between flow targets and economic gain when flow restriction is reduced below 1,416 m^3/s. The maximization of profit without consideration of environmental flow, however, represents an extreme case. Visually assessing the trade-offs between multiple objectives helps in the selection of policies that achieve a balance between different metrics of system performance.

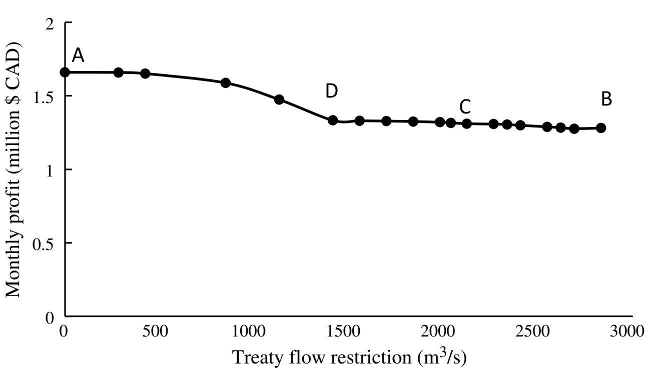

Fig. 7. Trade-off surface between economic gain and environmental consideration for July

Benefits and Possible Challenges for Pumped Storage

Hydro reservoirs are often used for storing electric energy generated by nondispatchable sources, provided that the power plants are connected by a common grid and that transmission capacity is sufficient to allow load-leveling. Apart from revenue considerations, the SAB PGS is operated for several reasons. First, the SAB complex, being one of few carbon-free resources in Ontario with black-start capability, energizes a portion of the grid without being dependent on an outside electricity supply. It automatically adjusts output based on electronic signals to provide frequency control and to maintain balance between demands. Second, the inherent nature of pumped hydro operation allows it to serve as backup for intermittent sources by providing power when production from these sources falls short of load. Third, regulated hydropower such as the SAB PGS can connect neighboring control areas for delivering electricity when such economic opportunities arise. However, such interjurisdictional transactions are typically governed by transmission capacity and energy prices in surrounding states/countries. On top of all of these factors, the SAB PGS is unique in terms of its functionality. With its ability to rapidly move water in and out of the reservoir, it maintains water elevation at the crossover, which is critical in ensuring appropriate water diversion from the Niagara River (Maricic et al. 2009). It also complements the operations of the two run-of-the-river hydropower plants at Niagara by maximizing available head.

Despite pumped storage's potential, several technical, environmental, social, and geopolitical constraints have led to its underutilization. Development and operation of hydro projects mandate effective water resource management, which is complex and often requires consideration of a broad range of social, economic, and environmental trade-offs. Being a transboundary water system, the Niagara River faces more of those challenges than other systems in balancing various water needs. First, in the case of Niagara effective water sharing among sovereign states, here Canada and the United States, requires an agreement or contract between the parties. However, the tendency for the respective governments to resist influence or control over assets challenges the very concept of shared resources. Second, geographic and political issues surrounding the use of water resources are of paramount interest when dealing with transboundary systems. Certainly the 1950 treaty acts as a major policy constraint for hydropower plants at Niagara. The expiration of the treaty in 2000, which is currently being extended on an annual basis, opens the door for renegotiation with opportunities for additional generation. However, such potential is seldom fully explored due to complexity and negative public reaction against alteration of an age-old treaty. To make matters even more complicated, neighboring jurisdictions often have different priorities for conflicting water uses. One possible example is the dismissal of the petition seeking hydrologic separation of the Chicago Area Waterway from the Great Lake basin despite being identified as a potential entryway for Asian Carp, an invasive species threatening the Great Lakes ecosystem. Third, climate change consideration—frequently disregarded by policy makers—requires collaboration for ensuring optimal use of water resources. Reflecting on such risks is indeed important for the Great Lake watershed given the sustained water level drop in the basin in late 1990s that has been found to be related to El Niño events.

Water and energy systems are inextricably linked. This paper explores trade-offs, the result of which can be used for a possible renegotiation. With the current flow restrictions, the model suggests how the selection of operating hours and flows would lead to profit maximization. However, it refrains from making any direct suggestions based on the analysis, given that effective water resource management requires consideration of a host of issues.

Conclusions and Recommendations

Operational systems inherit various design, operational, and jurisdictional constraints that complicate both the operation and redesign of components. The paper discusses such constraints with respect to the transboundary river system at Niagara. Although pumped storage principally operates for reasons of grid balancing, considerations such as relative cost, profitability, and long term viability are also important. This exploratory study considers this perspective and formulates a revenue generation model for pumped-storage operation. A 2.5–10% reduction in electricity rate, due to an increased pumped storage contribution, can result in a 1–24% reduction in profit depending on the month. Whereas increasing the reservoir footprint may bring little financial gain, energy price variability and pumping generation cycles appear to be the dominant factors in PSH profitability. The conflict between flow targets and economic gain is quite strong for flow restriction values between 0 and 1,500 m^3/s, but it is milder for increasing the value of the treaty restrictions. Energy revenues presented here are derived assuming operation of the facility in the Ontario spot market, whereas capacity revenues such as for black-start and automatic generation control are largely ignored. The profit values reported here are rough estimates only and depend on the persistence of similar market and flow conditions.

The proposed model can be used by power authorities to evaluate the potential of pumped hydro with respect to other emerging storage options such as CAES, batteries, and the like, once they achieve the desired scalability. The authors expect this paper to contribute as a foundation for further research on the role of pumped hydro in grid balancing. An interesting future extension of this work may be the study of SAB PGS profitability due to the impact of changing time pattern of price volatility with the integration of intermittent renewables.

Appendix. Constraints Used in the Model

1. The volume of water pumped into the reservoir is less than or equal to the maximum pumping flow:

$$u_i \leq f x_i \tag{7}$$

where u_i = volume of water pumped in hour i; and f = maximum pumping flow per hour.

2. The volume of water released is less than or equal to maximum turbine flow:

$$v_i \leq h y_i \tag{8}$$

where v_i = volume of water released in hour i; and h = maximum turbine flow per hour.

3. The flow balance relationship is as follows:

$$S_{i+1} = S_i + u_i - v_i \tag{9}$$

where S_i = volume of water in the storage reservoir at the start of i.

4. The volume released is less than or equal to the water stored in the reservoir:

$$v_i \leq S_i \tag{10}$$

5. The water stored in the reservoir is less than or equal to the reservoir capacity:

$$S_i \leq C \tag{11}$$

where C = reservoir capacity.

6. The volume of water pumped into the reservoir is less than or equal to the water available:

$$u_i \leq \text{available flow at SAB PGS} \tag{12}$$

7. Non-negativity constraints

$$x_i, y_i, u_i, v_i, S_i \geq 0 \tag{13}$$

Notation

The following symbols are used in this paper:

C = reservoir capacity;
c_i = cost incurred in hour i from pumping of unit volume of water;
E = maximum power generation;
f = maximum pumping flow per hour;
g = gravitational acceleration;
H = storage water level;
H_{loss} = head loss;
H_n = net head;
H_{tail} = tail water level;
h = maximum turbine flow per hour;
K = constant;
P = power generation (W);
Q = volume of water released through turbines;
r_i = revenue generated in hour i from release of unit volume of water;
S_i = volume of water in storage reservoir at the start of i;
u_i = volume of water pumped in hour i;
v_i = volume of water released in hour i;
x_i = decision to operate pump at ith hour;
y_i = decision to generate at ith hour;
η = hydropower plant overall efficiency; and
ρ = density of water.

References

Afshar, M. H. (2012). "Large scale reservoir operation by constrained particle swarm optimization algorithms." *J. Hydro-Environ. Res.*, 6(1), 75–87.

Aggarwal, S. K., Saini, L. M., and Kumar, A. (2008). "Electricity price forecasting in Ontario electricity market using wavelet transform in artificial neural network based model." *Int. J. Control Autom. Syst.*, 6(5), 639–650.

Auditor General of Ontario. (2011). *2011 Annual Rep. Queen's Printer for Ontario*, Toronto.

Ayodele, T. R., and Ogunjuyigbe, A. S. O. (2015). "Mitigation of wind power intermittency: Storage technology approach." *Renewable Sustainable Energy Rev.*, 44, 447–456.

Bosona, T. G., and Gebresenbet, G. (2010). "Modeling hydropower plant system to improve its reservoir operation." *J. Water Resour. Environ. Eng.*, 2(4), 87–94.

British Petroleum Company. (2015). *BP statistical review of world energy*, London.

Caralis, G., Papantonis, D., and Zervos, A. (2012). "The role of pumped storage systems towards the large scale wind integration in the Greek power supply system." *Renewable Sustainable Energy Rev.*, 16(5), 2558–2565.

Catalão, J. P. S., Pousinho, H. M. I., and Contreras, J. (2012). "Optimal hydro scheduling and offering strategies considering price uncertainty and risk management." *Energy*, 37(1), 237–244.

Chang, M. K., Eichman, J. D., Mueller, F., and Samuelsen, S. (2013). "Buffering intermittent renewable power with hydroelectric generation: A case study in California." *Appl. Energy*, 112, 1–11.

Evans, A., Strezov, V., and Evans, T. J. (2009). "Assessment of sustainability indicators for renewable energy technologies." *Renewable Sustainable Energy Rev.*, 13(5), 1082–1088.

Fleten, S. E., and Kristoffersen, T. K. (2008). "Short-term hydropower production planning by stochastic programming." *Comput. Oper. Res.*, 35(8), 2656–2671.

Gallant, P. (2015). *WCO–Wind concerns Ontario*, ⟨http://www.windconcernsontario.ca/ontario-surplus-power-exports-cost-consumers-in-january/⟩ (Aug. 8, 2015).

German Advisory Council. (2011). "Pathways towards a 100% renewable electricity system." ⟨http://www.umweltrat.de/SharedDocs/Downloads/EN/02_Special_Reports/2011_10_Special_Report_Pathways_renewables.pdf?__blob=publicationFile⟩ (Aug. 8, 2015).

Government of Canada. (2015). *Global affairs Canada*, ⟨http://www.treaty-accord.gc.ca/text-texte.aspx?id=100418⟩ (Jun. 8, 2013).

Griffith, R. E., and Stewart, R. A. (1961). "A nonlinear programming technique for optimization of continuous processing systems." *Manage. Sci.*, 7(4), 379–392.

Haguma, D., Leconte, R., Krau, S., Côté, P., and Brissette, F. (2010). "Water resources optimization method in the context of climate change." *Water Resour. Plann. Manage.*, 10.1061/(ASCE)WR.1943-5452.0000445, 04014051.

Helset, A., Gjelsvik, A., Mo, B., and Linnet, Ú. (2013). "A model for optimal scheduling of hydro thermal systems including pumped-storage and wind power." *IET Gener. Transm. Distrib.*, 7(12), 1426–1434.

IESO (Independent Electricity System Operator). (2015). *Ontario's electricity hub*, ⟨http://www.ieso.ca/⟩ (Jul. 31, 2015).

Ingebretsen, E., and Johansen, T. H. G. (2014). "The profitability of pumped hydro storage in Norway: A study of six pumped hydro storage plants." Master's thesis, Norwegian School of Economics, Bergen, Norway.

IPCC (Intergovernmental Panel on Climate Change). (2011). *Special report on renewable energy sources and climate change mitigation*, ⟨http://srren.ipcc-wg3.de/⟩ (Aug. 7, 2015).

Kamodkar, R. U., and Regulwar, D. G. (2013). "Multipurpose reservoir operating policies: A fully fuzzy linear programming approach." *J. Agric. Sci. Technol.*, 15(6), 1261–1274.

Kanakasabapathy, P. (2013). "Economic impact of pumped storage power plant on social welfare of electricity market." *Electr. Power Energy Syst.*, 45(1), 187–193.

Kusakana, K. (2015). "Feasibility analysis of river off-grid hydrokinetic systems with pumped hydro storage in rural applications." *Energy Convers. Manage.*, 96, 352–362.

Latorre, J. M., Cerisola, S., Ramos, A., Perea, A., and Bellido, R. (2014). "Coordinated hydropower plant simulation for multireservoir systems." *Water Resour. Plann. Manage.*, 10.1061/(ASCE)WR.1943-5452.0000306, 216–227.

Linares, P., Santos, F. J., and Ventosa, M. (2008). "Coordination of carbon reduction and renewable energy support policies." *Clim. Policy*, 8(4), 377–394.

Maricic, T., Haber, D., and Pejovic, S. (2009). "Niagara pump generating station proven functionality unique in Canada." *Proc., IEEE Electrical Power and Energy Conf.*, NJ.

Maxim, A. (2014). "Sustainability assessment of electricity generation technologies using weighted multi-criteria decision analysis." *Energy Policy*, 65, 284–297.

Mo, L., Lu, P., Wang, C., and Zhou, Z. (2013). "Short-term hydro generation scheduling of Three Gorges-Gezhouba cascaded hydropower plants using hybrid MACS-ADE approach." *Energy Convers/ Manage.*, 76, 260–273.

Moeini, R., Afshar, A., and Afshar, M. H. (2011). "Fuzzy rule-based model for hydropower reservoirs operation." *Electr. Power Energy Syst.*, 33(2), 171–178.

Neufville, R. D. (1990). *Applied systems analysis: Engineering planning and technology management*, McGraw-Hill.

NOAA (National Oceanic and Atmospheric Administration). (2013). *Tides & currents*, ⟨http://tidesandcurrents.noaa.gov/waterlevels.html?id=9063007⟩ (Dec. 27, 2013).

Ontario Power Generation. (2010). ⟨http://www.opg.com/about/regulatory-affairs/Documents/Issue%2006.02.pdf⟩ (Dec. 1, 2012).

Palacios-Gomez, F., Lasdon, L., and Engquist, M. (1982). "Nonlinear optimization by successive linear programming." *Manage. Sci.*, 28(10), 1106–1120.

Prasad, S. A., Umamahesh, N. V., and Viswanath, G. K. (2012). "Short-term real-time reservoir operation for irrigation." *Water Resour. Plann. Manage.*,10.1061/(ASCE)WR.1943-5452.0000234, 149–158.

Rangoni, B. (2012). "A contribution on electricity storage: The case of hydro-pumped storage appraisal and commissioning in Italy and Spain." *Util. Policy*, 23, 31–39.

Rehman, S., Al-Hadhrami, L. M., and Alam, M. M. (2015). "Pumped hydro energy storage system: A technological review." *Renewable Sustainable Energy Rev.*, 44, 586–598.

Salevid, K. (2013). *Market requirements for pumped storage profitability*, ⟨http://uu.diva-portal.org/smash/get/diva2:661286/FULLTEXT01.pdf⟩ (Aug. 2, 2015).

Sharma, R. N., Chand, N., Sharma, V., and Yadav, D. (2015). "Decision support system for operation, scheduling, and optimization of hydropower plant in Jammu and Kashmir region." *Renewable Sustainable Energy Rev.*, 43, 1099–1113.

Sousa, J. A. M., Teixeira, F., and Faias, S. (2014). "Impact of a price-maker pumped storage hydro unit on the integration of wind energy in power systems." *Energy*, 69, 3–11.

Steffen, B. (2012). "Prospects for pumped-hydro storage in Germany." *Energy Policy*, 45, 420–429.

Zafirakis, D., Chalvatzis, K. J., Baiocchi, G., and Daskalakis, G. (2013). "Modeling of financial incentives for investments in energy storage systems that promote the large-scale integration of wind energy." *Appl. Energy*, 105, 138–154.

Zareipour, H., Bhattacharya, K., and Cañizares, C. A. (2007). "Electricity market price volatility: The case of Ontario." *Energy Policy*, 35(9), 4739–4748.

Zareipour, H., Cañizares, C. A., Bhattacharya, K., and Thompson, J. (2006). "Application of public-domain market information to forecast Ontario's wholesale electricity prices." *IEEE Trans. Power Syst.*, 21(4), 1707–1717.

Zhang, S., Andrews-Speed, P., and Perera, P. (2015). "The evolving policy regime for pumped storage hydroelectricity in China: A key support for low-carbon energy." *Appl. Energy*, 150, 15–24.

Zhu, J., Jordan, G., and Ihara, S. (2000). "The market for spinning reserve and its impacts on energy prices." *IEEE Power Engineering Society Winter Meeting*, Vol. 2, NJ, 1202–1207.