Influence of De-regulated Electricity Markets on Hydropower Generation and Downstream Flow Regime

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Abstract

In the Southeastern U.S., competition for water is becoming increasingly contentious due to rapid growth in demand. As state and regional managers seek to balance the water needs of humans and the environment, the timing of steamflows—in addition to their quality and quantity—is an important concern, and one that can be significantly impacted by hydropower generation. In de-regulated electricity markets, where the price of wholesale electricity can be volatile throughout the day, generators may have financial incentives to alter generation schedules on a real-time basis. Hydroelectric dams' ability to respond to changes in electricity demand more rapidly and at lower cost than thermal generators (i.e., coal, nuclear and natural gas) makes them well suited to take advantage of short term spikes in electricity prices. However, the hydropower release schedules that result may lead to flow regimes that differ significantly from natural patterns. This study explores the potential for electricity market dynamics to impact flow regimes downstream from hydroelectric dams, as well as the financial cost and efficacy of efforts to mitigate the effects of unnatural flow regimes. Three dam sites in the Roanoke River Basin (NC & VA) are modeled under four different operational scenarios (i.e. run-of-river, current operations, market utilization, and unregulated). Collectively, the first three span the range of operations that are possible with dams in place, from a strategy that attempts to more closely mimic natural flows (run-of-river) to one in which a utility takes advantage of all its revenue generating potential (market utilization). The unregulated scenario, which assumes no dams are in place, is employed to compare each 'regulated' scenario with natural flows. Indicators of hydrologic alteration (IHAs) that reflect five environmentally critical components of river flow (magnitude, timing, frequency, rate-of-change and duration) are used to quantify the impact of different operational scenarios on downstream flows. For most IHAs considered, results show the general trend between hydropower revenue and deviation from unregulated flows to be positive, albeit somewhat dependant on the year (2006-2009). Implementing a run-of-river policy frequently yields flow regimes that mimic unregulated flows closer than current operations, but these improvements appear insignificant a majority of the time and come at the costs of substantial foregone hydropower revenue. In most cases, the scale of any difference in flow regime resulting from the pursuit of revenue in new markets is dwarfed by the additional revenue generating potential of such a strategy.

Acknowledgements

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Introduction

Efforts to reduce pollution and lower greenhouse gas emissions will benefit from an increased reliance on renewable energy production. In 2008, hydropower accounted for 67% of U.S. renewable energy generation and 6% of total U.S. generation (EIA, 2008). While significant, these numbers understate the importance of hydropower as an energy storage mechanism and a peaking resource. On timescales that range from hourly to seasonal, hydroelectric dams store water (i.e. potential energy) during periods of relatively low electricity demand and then release water during periods of relatively high demand. In addition, the low variable costs of hydropower production and its minimal ramp-up time mean it can be used to respond to short-term changes in electricity demand more rapidly and at lower cost than thermal generators (e.g., coal, nuclear and natural gas) (NAS, 2010). These advantages also make hydropower a useful complement to more intermittent renewable energy sources, such as solar and wind (DOI, 2005).

Although hydroelectric dams have many positive aspects, concerns over their environmental impacts have motivated efforts to reduce hydropower generation, or, in some cases, remove dams altogether (Babbitt, 2002; Hart and Poff, 2002). Consequently, there is a critical need for understanding the tradeoffs between hydropower generation and environmental quality, as well as methods for integrating this knowledge into the development of more sustainable natural resource management strategies.

Previous attempts to characterize the impacts of hydropower generation on environmental quality include investigations of dams' impacts on riparian vegetation (Auble et al., 1993; Nilsson et al., 1997; Townsend, 2001) and downstream geomorphology (Ligon et al., 1995; Shields et al., 2000, Shields et al., 2009), as well as macroinvertebrate and fish communities (Gorman and Karr, 1978; Suen et al., 2009; Poff and Zimmerman, 2010). A subset of this research has focused on how dams alter the natural flow regime of rivers (Poff et al., 1989, Richter et al., 1996; Poff et al., 1997, Vogel et al., 2007), where flow regime is defined as the magnitude, duration, frequency, rate of change, and timing of river flows. Collectively, these five categories of river flow are considered to comprise a master ecological variable that influences the abundance and distribution of species within lotic ecosystems (Power, 1995). Efforts to develop explicit relationships that connect the category and degree of flow regime alteration with specific ecological responses are ongoing; however, a significant body of research shows that disrupting the natural flow of rivers can result in decreases in diversity, abundance and other ecological demographic parameters across species (Poff and Zimmerman, 2010). Previous research has also begun to explore the short-run economic cost of imposing environmental restrictions on hydroelectric dams (Edwards, 1999; Harpman, 1999; Kotchen et al., 2006; Jager and Bevelhimer, 2007). These types of studies, combined with methods for valuing ecosystems (Loomis, 1995), can provide policy makers with tools to assess the costs and benefits of dam management strategies. Nonetheless, these past attempts to characterize tradeoffs between hydropower generation and ecosystem quality have largely ignored a potentially critical factor.

Recent regulatory changes have resulted in the emergence of de-regulated electricity markets (Rothwell and Gomez, 2003), a new institutional arrangement that has the ability to significantly impact hydropower facilities (Whisnant et al., 2009). Electric utilities that participate in de-regulated electricity markets (i.e., primarily those in the West Coast, Southwest, and East regions of the U.S.) experience hourly fluctuations in market prices for both energy and ancillary services (a term described later) due to rapid changes in demand and a lack of electricity storage capability. Since hydropower can be used to quickly respond to these changes in market prices, dam releases (and thus river flows) may increasingly be linked to de-regulated market behavior. Compared to hydroelectric units operating in a regulated environment, those in a de-regulated market may result in more variable and less predictable flows. As such, there is a need to explore the connections between de-regulated electricity market dynamics, hydropower generation, and downstream environmental quality.

This study investigates the potential for participation in a de-regulated electricity market to impact a hydropower utility's revenue stream and flow regimes downstream from hydroelectric dams. Particular attention is paid to the scale of these effects relative to those of three other modeled scenarios (current operations, run-of-river, and unregulated). Hydropower operations at three dam sites in the Roanoke River basin (Mid-Atlantic region of the U.S.) are modeled over a four year period (2006-2009). Flow regime statistics that reflect five environmentally critical components of river flow (magnitude, timing, frequency, rate-of-change and duration) are used to assess the impacts of different operational scenarios on downstream flows, relative to unregulated flows. Results then describe the relationship between hydropower revenues and deviation of downstream flows from the natural flow regime.

Study Area

The Roanoke River basin (Figure 1) flows southeast from the Blue Ridge escarpment in Virginia to the Albemarle Sound in North Carolina. The Lower Roanoke River basin includes three hydroelectric dams, the largest being John H. Kerr Dam (owned by the U.S. Army Corps of Engineers), which was completed in 1953. The powerhouse at Kerr Dam has a total installed generating capacity of 206 Megawatts (MW), and the turbine flow capacity at Kerr Dam is about 35,000 cubic feet per second (cfs). Immediately downstream (about 30 miles) from Kerr Dam is Gaston Dam, built in 1963, which is owned and operated by Dominion, an investor-owned energy utility. Gaston Dam has a total generating capacity of 224MW and a turbine flow capacity of 44,000cfs. Downstream from Gaston Dam (about 8 miles) is Roanoke Rapids Dam, built in 1955, also owned by Dominion, which has a somewhat smaller generation capacity (104MW) and turbine flow capacity (20,000cfs). In general, due to constraints on reservoir level fluctuations at Gaston Dam and Roanoke Rapids Dam, the timing and magnitude of hydropower releases made at Kerr Dam largely dictate the schedule of releases at the two downstream dams. It is also important to note that there is minimal free flowing river between Kerr Dam and the Gaston reservoir; likewise, there is no free flowing river between Gaston Dam and Roanoke Rapids Dam. As a result, in this study operations at all three dams are modeled synchronously (i.e. there is no delay between a release at Kerr Dam and the availability of that water for release at Gaston Dam), with attention to environmental impacts focused on the long stretch of free flowing river downstream of Roanoke Rapids Dam.

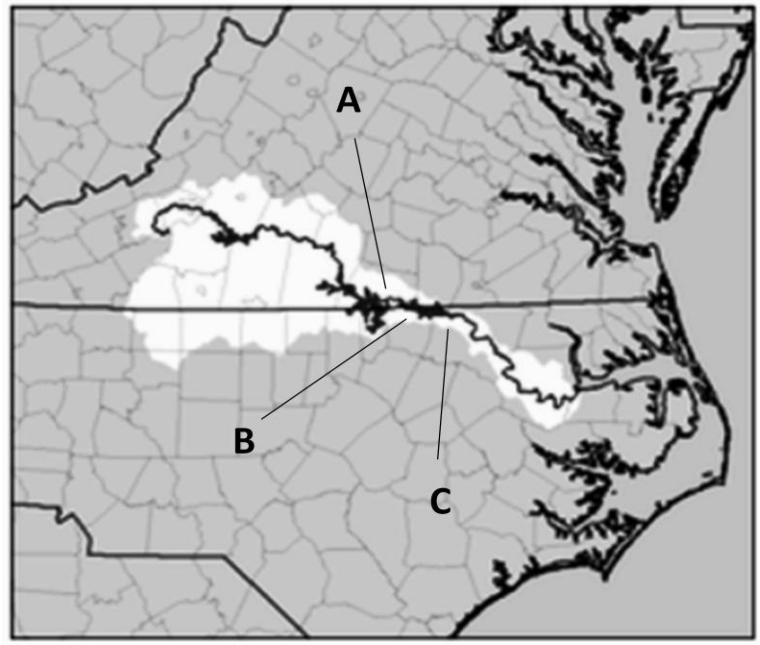

Figure 1. The Roanoke River basin (white) of North Carolina and Virginia, U.S. Dams are labeled as follows: A -- John H. Kerr Dam; B-- Gaston Dam; C-- Roanoke Rapids Dam.

This stretch includes one of the largest and least-fragmented river swamp forest ecosystems remaining in the eastern United States (Lynch, 1981). This area and its floodplain have been identified by The Nature Conservancy (TNC), the US Fish and Wildlife Service (USFWS), and the State of North Carolina as critical resources for the conservation of bottomland hardwoods and other riparian and in-stream biota (Pearsall et al., 2005). Numerous studies have explored the range of impacts that river flow regulation (i.e. dams) has had on the ecosystems of the Lower Roanoke River basin (Cobb, 1990; Richter, 1996; Konrad, 1997; Rice and Peet, 1997; Richter, 1997; Townsend and Walsh, 1997; Butler, 1998; Hochman, 1999; Hochman, 2000; Graham and Cannon, 2000; Pearsall, 2005). However, all of these studies pre-date a potentially important change in the Roanoke River basin: the advent of de-regulated electricity markets.

De-regulated Electricity in the Roanoke River Basin

The total volume of water available to be released from Kerr Dam during any given week is established by the U.S. Army Corps of Engineers (USACE) and based on factors related to current storage, recent (and predicted) inflows and maintenance of flood storage capacity. Until 2005, the timing of hourly (within-week) releases at Kerr Dam was also determined by the USACE, which coordinated hydropower generation at Kerr Dam with periods of high electricity demand for designated federal power customers. However, since May 2005 the scheduling of hourly releases at Kerr Dam has been largely determined by Dominion, which relays requests for within-week releases directly to Kerr Dam; the volume of the total weekly release is still set by the USACE (Whisnant, 2009). This change has been concurrent with Dominion's active participation in PJM Interconnection (PJM), a regional transmission organization (RTO) that coordinates the operation of an extremely large electrical grid and de-regulated electricity market, primarily in the Mid-Atlantic region of the U.S. Thus, Dominion largely dictates the schedule of hourly water releases at all three dams in the Lower Roanoke River basin, with the resulting hydropower then being sold into the PJM market.

PJM Market Operations

PJM members (e.g. Dominion) can buy and sell electricity in two different wholesale energy markets, which operate on a day-ahead and real-time basis, respectively. In the day-ahead energy market, participants submit sell/bid offers to buy electricity for each hour of the following day. Sell and bid offers consist of a quantity of energy (MWh) to be sold or purchased, and a desired price ($/MWh), where sell prices typically correspond roughly to each generator's cost of energy production. For each hour of the following day, PJM then ranks sell-offers, from least to most expensive, and the price of the last sell-offer required to satisfy day-ahead forecasted demand sets the market-clearing energy price. All sellers with offers below this price then generate a return equal to their respective bid quantities multiplied by the market-clearing price. (Lambert, 2001; Rothwell and Gomez, 2003).

Most generation sold in PJM is sold in the day-ahead market (www.pjm.com). However, throughout the operating day, PJM also coordinates an hourly real-time energy market, which is used to meet real-time electricity demand when it varies relative to forecasted day-ahead demand. An hourly, real-time market-clearing price is determined in a manner similar to the day-ahead market (i.e. via the ranking of bid/sell offers submitted to PJM), and transactions are consummated as necessary in order to meet real-time demand (www.pjm.com; Lambert, 2001).

In addition to operating day-ahead and real-time energy markets, PJM also coordinates market-based pricing of various “ancillary services”, which support the reliable operation of the electrical grid as it moves electricity from generating resources to retail customers. Three different types of ancillary services markets are operated by PJM, and of these, regulation service, which corrects for grid-wide, short-term changes in electricity use that may cause the power system to operate above or below the standard of 60 Hz, is the only one considered in this study (synchronized reserve and black start service are the other two). PJM maintains hourly, grid-wide requirements for regulation service capacity. Each load serving entity (or “LSE” – a supplier of electricity to end-users and wholesale customers) participating in PJM is responsible for providing regulation service capacity equal to 1% of its day-ahead forecasted demand. These LSEs (of which Dominion is one) can satisfy their individual requirements using self-generation, bilateral agreements, or by buying regulation service from others in the marketplace. Potential regulation service providers submit hourly sell-offers on a day-ahead basis, and the market clearing price for regulation service for any given hour is then set in real-time by the last sell-offer required to meet the grid-wide requirement. Sellers in the regulation service market agree to (if called upon by PJM) increase or decrease generation by an incremental amount (MWh) specified in their respective sell-offers (www.pjm.com). Figure 2 shows an example decision making timeline for participation in both energy markets, as well as the regulation service market.

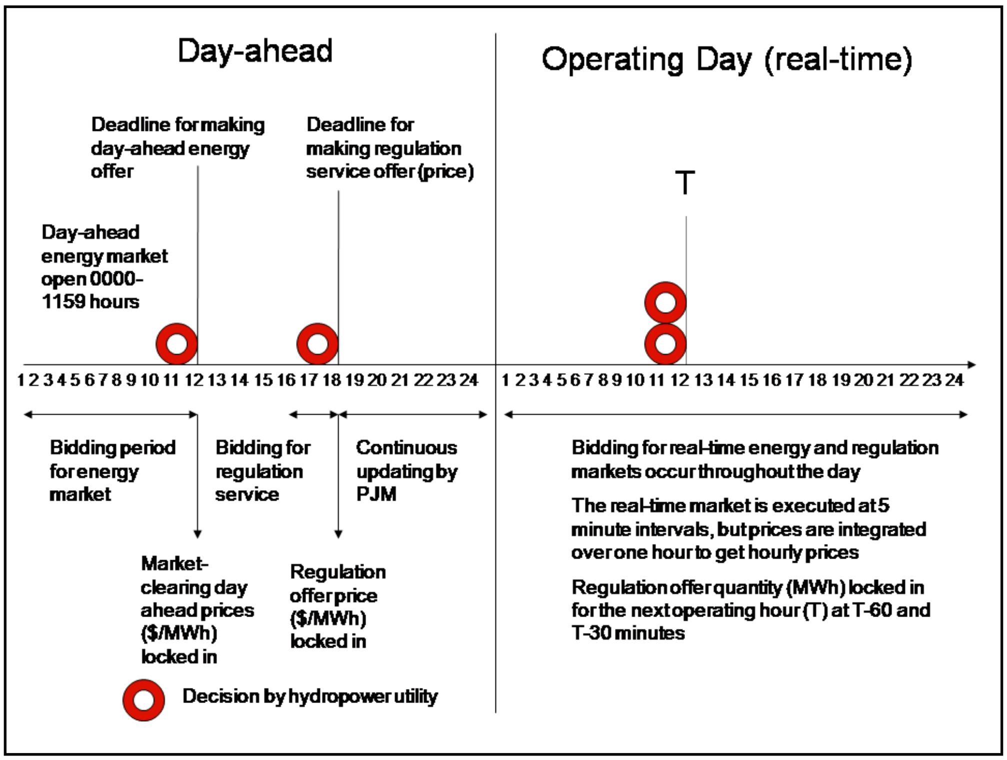

Figure 2. Decision-making timeline for modeled hydropower utility selling in the PJM energy and regulation service markets.

Another characteristic of de-regulated electricity markets such as PJM is the hourly fluctuation of market prices. In general, the day-ahead markets for energy and regulation service operate in a manner that maintains a relatively low level of real-time price volatility by scheduling as much generation as possible 24 hours in advance. Nevertheless, price volatility in the real-time energy market is inevitable as a result of short-term, unexpected changes in supply or demand (a problem exacerbated by the difficulty of storing electricity). The price in the day-ahead energy market is actually higher than in the real-time energy market about 70% of the time; however, during the other 30%, real-time energy prices are higher, and 1-2% of the time real-time energy prices can spike to very high levels. As an example, Figure 3 shows the hourly variation in real-time electricity price over seven consecutive summer days (Sunday to Saturday) within the PJM market (Dominion Hub).

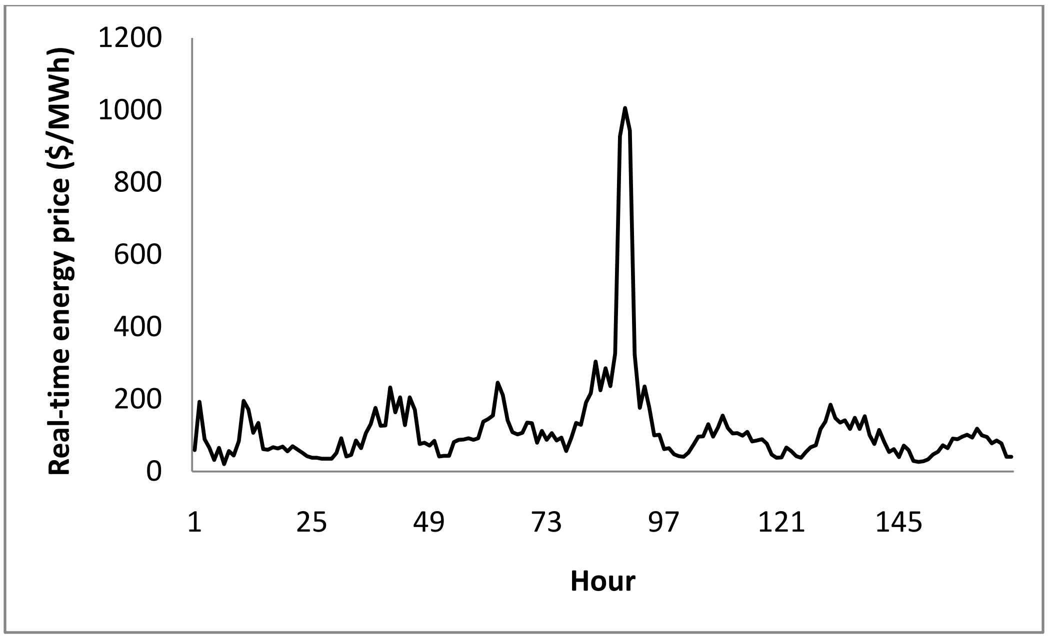

Figure 3. The price of electricity in the real-time energy market over seven consecutive days in summer (8/5/2007 – 8/11/2007).

On August 8, 2007 (a Wednesday), the real-time price of electricity briefly spiked to a maximum of $1,006/MWh, more than 1000% greater than the average retail price of electricity in North Carolina ($80-85/MWh) (www.eia.gov). The short duration (3 hours) of this spike is a common aspect of electricity price volatility in de-regulated markets, and one that is generally characteristic of price behavior for non-storable commodities experiencing short term changes in demand (Deng, 2000). As such, hydropower utilities may be uniquely well suited to significantly raise revenues by increasing the frequency with which they participate in the real-time energy market (as well as the regulation service market). The purpose of this study is to determine if the hydropower release schedules resulting from such a strategy would lead to flow regimes that differ significantly from those resulting from current practices, and how both regimes compare with unregulated flow patterns.

Methods

Investigation of the relationship between de-regulated market behavior, hydropower generation and downstream flow regime centers around four different modeled operational scenarios: current operations, market utilization, run-of-river and unregulated. Each 'regulated' scenario (current operations, market utilization and run-of-river) consists of linked models of basin hydrology and power generation. The unregulated scenario, which simulates conditions in which no dam exists, only consists of a hydrologic model.

Little information regarding Dominion's participation in PJM is publically available, so modeling the 'current operations' scenario focuses on replicating observed hourly releases at Kerr Dam for the period 2006-2009. Results suggest that Dominion is not currently participating in the real-time energy or ancillary service markets in a significant way. There is also considerable interest in exploring the upper and lower bounds of the many operational scenarios that are possible with dams in place. The hypothetical 'market utilization' scenario represents one extreme by assuming that a utility uses improved information regarding real-time prices and forecasted demand to significantly increase generating revenue in multiple PJM markets. The 'run-of-river' scenario represents the other extreme (a hypothetical "low environmental impact" approach), one in which flows are assumed to more closely mimic natural patterns while still allowing the dam to meet water supply and flood control objectives. Lastly, there is the 'unregulated' scenario, in which none of the three dams are in place and the river experiences natural flow conditions. Resultant flows from the unregulated scenario are compared alongside those of the regulated scenarios in order to quantify deviation from the natural flow regime.

Each hydrologic model simulates daily storage and flow values at the aforementioned three dam sites for the period 1929-2009. Inputs to the hydrologic model include historical records of runoff, evaporation and precipitation, all provided by the North Carolina Department of Water Resources. Dam operating specifications for each reservoir include: Storage-area-elevation curves, head differentials, dam turbine capacities, dam generating efficiencies, reservoir guide curves (schedules describing target reservoir elevation for each day of the year), seasonal water supply demands, minimum flow requirements (if applicable), and USACE energy contracts (if applicable). Many of the dam operating specifications were taken from the Roanoke River Basin Operations Model (RRBROM), which was developed in 2005 by HydroLogics, Inc. with funding from the State of North Carolina, The Nature Conservancy, and Dominion (Pearsall et al., 2005).

For each regulated scenario, output from the hydrologic model (i.e. daily reservoir storage and discharge values) is used as input for a power generation model that simulates the hourly hydropower operations of Kerr, Gaston and Roanoke Rapids Dams. The power generation model maximizes the number of hourly hydropower releases made at turbine generating capacity for each dam, while also providing water for ‘ramping’ hours (hours of intermediate flow surrounding a period of high flow). Observational data used to develop the power generation model (PJM market prices and day-ahead demand forecasts) was limited to the years in which these dams have been a part of the PJM market (2006-2009).

Current Operations

Hydrologic Model

Model validation for the 'current operations' scenario focused on Kerr Dam, because historical reservoir storage and flow data is available for Kerr Dam at multiple temporal resolutions. Interest in how dam operations vary with hydrologic condition led to the examination of reservoir operating practices during dry, wet, and normal years (Figure 4). These climatic distinctions were based on 12-month standardized precipitation indices (NC Climate Center, 2010), with 'wet' years defined as those with an average precipitation index that is greater than (or equal to) the 75th percentile of the historical record (1912-2009); 'dry' years defined as those with an average precipitation index less than (or equal to) the 25th percentile; and 'normal' years are everything in between. In general, the hydrologic model more closely tracks observed flows and reservoir storage at Kerr Dam during dry and wet years, perhaps a function of the very specific dam operating guidelines that exist for operating the dam during extremely dry and wet periods. Operations during normal hydrologic periods are subject to fewer operating constraints and allow more operator discretion, making them more difficult to model.

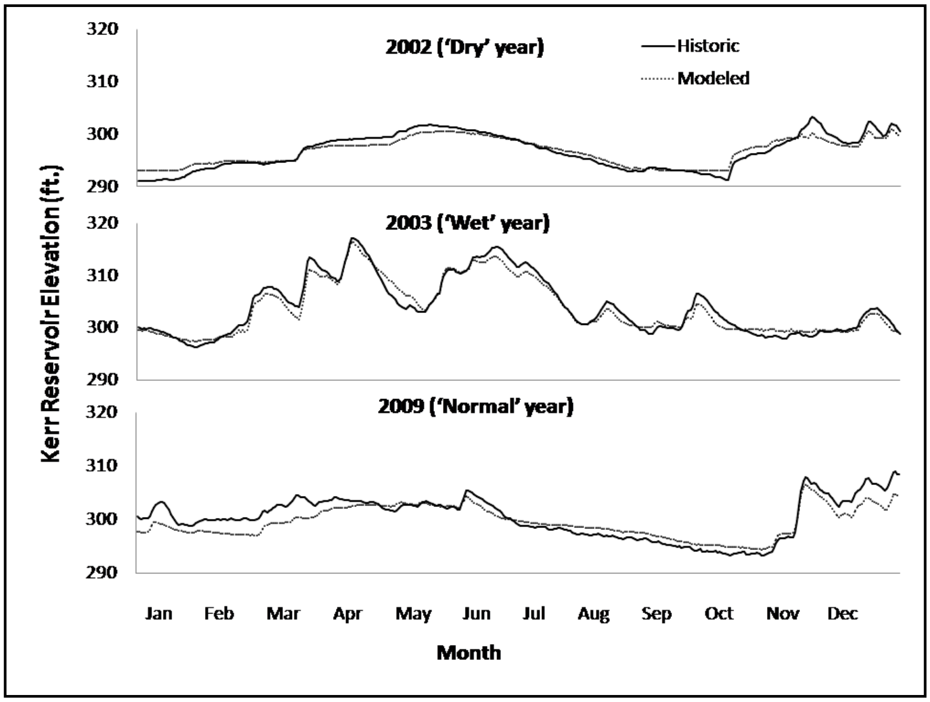

Figure 4. Modeled and observed reservoir elevation at Kerr Dam.

Power generation model

The power generation model simulates the hourly operation of Kerr, Gaston and Roanoke Rapids Dams for hydropower generation. As noted, the total volume of water available for release from Kerr Dam in a given week is set by the USACE. This constraint is simulated in the power generation model by combining output from the hydrologic model (i.e. daily discharge values from Kerr Dam) into 7-day intervals, yielding cumulative discharge values for days 1-7, 8-14, etc. throughout the year. The power generation model then takes the cumulative discharge values for each 7-day interval and allocates that volume on an hourly basis over the week.

In order to simulate hourly current operations at the three dams, several important aspects of Dominion's actual decision-making process are addressed, including Dominion's ability to use projected inflows and electricity demand forecasts for future periods in scheduling hydropower generation. This ability is simulated by assuming an 'operating horizon' in conjunction with historical PJM demand forecasts. In addition, choice of market participation (day-ahead energy, real-time energy or both; with or without regulation service) is modeled along with decision rules stipulating when and how Dominion will participate in each respective market. Validation of the power generation model for the current operations scenario focuses on observed hourly releases at Kerr Dam.

An ‘operating horizon’ is a term used to represent the number of consecutive days of projected inflows and demand forecasts that Dominion incorporates into its actual hourly decision making process. Depending on its length, an operating horizon augments (or limits) Dominion’s ability to consider information about future periods when scheduling hourly generation; it thereby enables Dominion to more (or less) effectively schedule generation concurrent with periods of the highest demand.

From a modeling perspective, the operating horizon is the number of consecutive days’ cumulative discharge and demand forecasts that are used to schedule generation. It can also be thought of as the size of a moving window nested within each discrete 7-day period. For example, a 4-day operating horizon means for day 1 of any given week the power generation model uses demand forecasts and cumulative discharges (from the hydrologic model) for days 1-4 to schedule hourly generation. Once simulated hourly discharge values for day 1 are complete, the model moves forward, with hourly discharges for days 2-4 then summed with simulated day 5 discharge (from the hydrologic model) to form the volume of water available for release during the next 4-day window. Similarly, hourly discharge values for day 2 are then completed, and the process is repeated for days 3-6 (and then, similarly for days 4-7). In general, the longer the operating horizon, the better the model is able to store water during periods of low forecasted demand and schedule generation during periods of the highest forecasted demand.

It is important to note the difference between the forecasted demand data used in this study and that which is actually available to Dominion when scheduling hydropower generation. Use of a full 7-day demand forecast is the way in which most utilities would initially schedule generation at all three dams, followed by continual revisions to their release schedules as the week progresses and updated demand and inflow forecasts become available. However, since historical multi-day demand forecasts are not publically available from PJM, the power generation models in this study use historical day-ahead demand forecasts (which are available). These forecasts include a lower level of uncertainty than the multi-day advance demand forecasts used by Dominion, so some brief discussion of the impacts of this assumption is warranted.

Weather forecasting is often the greatest source of error in power demand forecasts (The Brattle Group, 2006). Depending on the location and type of weather data considered in demand forecasting models, 1-day and 7-day demand forecasts have been shown to predict actual demand within a range of 1.5% - 2.5% mean average percentage error, with 1-day forecasts demonstrating a .25 – 1.0% advantage relative to 7-day forecasts (Taylor and Buizza, 2003). Thus, while the power generation model used in this study employs slightly better information than that which would have been available to Dominion when scheduling generation, the impact on results when modeling current operations is likely to be relatively small.

For each operational scenario, the decision rules regarding how to allocate water over the specified operating horizon are dictated by the markets in which the dams are participating. As an example, day-ahead market participation means hourly hydropower generation is scheduled over the operating horizon according to hourly, day-ahead forecasted demand in the PJM market (Dominion Hub). This is performed by first ranking each hour of the operating horizon (e.g. a 4-day operating horizon would have 96 ranked hours) in terms of its forecasted demand. Given the cumulative discharge for the operating horizon, this volume of water is allocated one hour at a time in order of decreasing forecasted demand.

Validation of hourly current operations involves comparing simulated hourly releases from the model with historical observations using a root mean square error (RMSE) metric. Results show that simulated hourly releases at Kerr Dam (2006-2009) replicate observed releases closest when a 4-day operating horizon is used, and when the dam operators are assumed to be participating in the day-ahead energy market only (Figure 5).

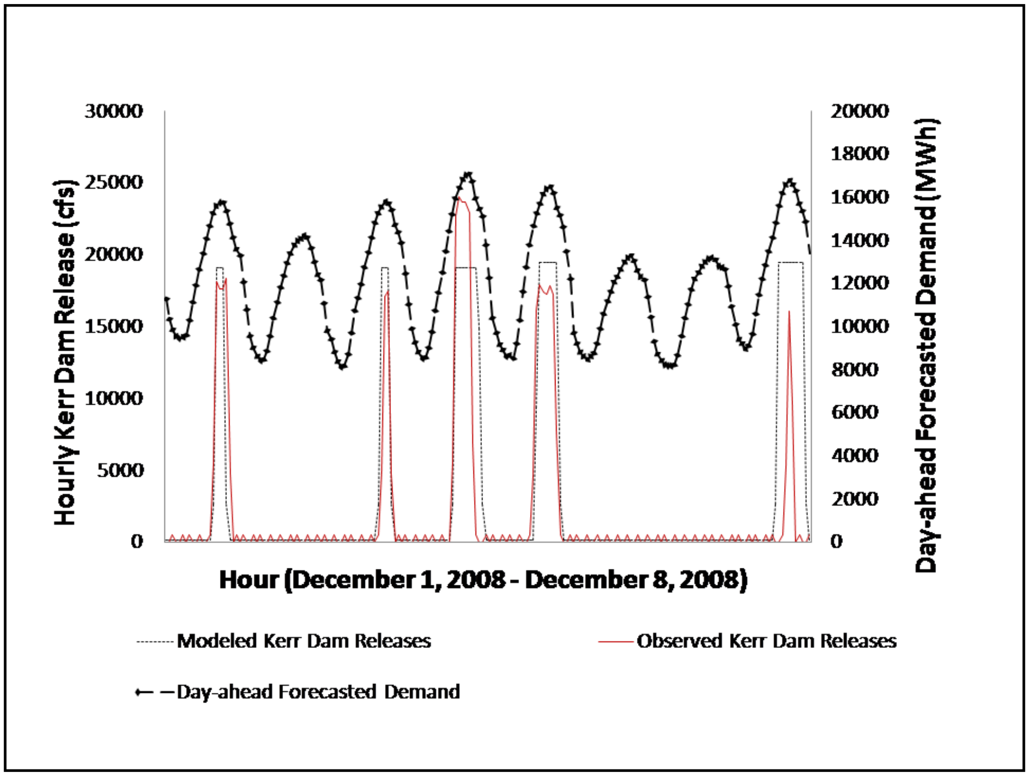

Figure 5. Modeled "current operations" versus historic hourly Kerr Dam releases.

Overall, results from our efforts to replicate the historical hourly operation of Kerr Dam strongly suggest that Dominion is *not* currently utilizing the real-time energy or regulation service markets in a significant way. However, due to the revenue generating potential of the real-time energy and regulation service markets, Dominion could very easily choose to become increasingly active in these markets over time. The next section addresses a potential future operating scenario where a utility does participate in the real-time energy and regulation service markets with the intent of increasing its power generation revenues.

Market utilization

Power generation model

The 'current operations' and 'market utilization' scenarios share the same hydrologic model (detailed above), so hydrologic input to the power generation model is the same for both. The market utilization scenario is designed as one 'extreme' of the spectrum of operational scenarios possible with dams in place. As such, it may incorporate some unrealistic assumptions, including the extent to which a utility can anticipate high real-time prices in a subsequent hour. However, due to the rapid execution of the real-time market (every 5 minutes) and the success of real-time price models (Mount, 2005), the market utilization scenario remains a reasonable (if hypothetical) upper bound. It does so by attempting to increase hydropower revenues (relative to the current operations) using a 7-day operating horizon and participation in both the day-ahead and real-time energy markets, as well as the regulation service market. A 7-day operating horizon represents a potential improved predictive ability of the utility in forecasting electricity demand. A series of decision rules then controls how water is allocated over the operating horizon to generate revenue in the three different markets.

First, cumulative discharge values for the operating horizon are allocated on an hourly basis for generation in the day-ahead energy market, similar to the process followed for the current operations scenario.

The second step in the market utilization scenario is participation in the regulation service market. Offers to sell regulation service are offers to increase or decrease generation in one hour by a certain amount (MWh) for a certain price ($/MWh), if called upon by the system operator. For each of the three dams under consideration, we assumed a static hourly regulation sell-offer of +/- 10MWh. Similar to the day-ahead and real-time energy markets, the regulation market clearing price is determined on an hourly basis by the last sell-offer needed to satisfy the grid-wide demand. Based on historical operation of the PJM regulation market, the grid-wide need for down-regulation (decrease in generation) is roughly as common as the need for up-regulation (increase in generation). In a given hour, the specific need for up or down regulation varies on a minute-to-minute basis; thus, if a generator is equally active as an up- and down-regulation resource, the result is no net change in scheduled generation. In addition, PJM may reserve +/-10MW of regulation service from a generator and simply employ less than this absolute amount. While this model does not explicitly describe sub-hourly processes, it does attempt to simulate regulation market behavior on an hourly time-step by using a random number generator over the interval [-10 10] to simulate the net magnitude and sign of the regulation service needed for each hour.

For generators that are self-scheduled by their owners (e.g. hydroelectric dams), the decision to participate in the regulation market must be made on a day-ahead basis, with no knowledge of the regulation market clearing price or the nature of the regulation signal (up or down regulation). As a result, in this study it is assumed that the utility participates in the regulation market during those hours where hydropower generation is scheduled for sale in the day-ahead market. Due to the timeline constraints for participation in the day-ahead market (Figure 2), water cannot be 'borrowed' (for participation in the real-time energy or regulation service markets) from a future hour within the same 36-hour bidding period (i.e. 12pm, day 'D-1' – 12am, day 'D'). Doing so would necessitate deviating from the previously finalized generating schedule for the day-ahead energy market. An additional consequence of this constraint is that all hours after 12pm on Day 6 are not eligible for participation in the real-time energy or regulation service markets.

Step three allows the modeled utility to deviate from its initial week-long generating schedule in order to take advantage of price increases in the real-time energy market. The decision rule for choosing when to participate in the real-time energy market is as follows: if, for any given hour of the week, there is 1) no day-ahead generation scheduled; and 2) the real-time price of electricity is above the 95th percentile of the 2006-2009 distribution ($147.11/MWh), then the model will participate in the real-time energy market. This is accomplished by 'borrowing' water from the lowest-ranked (in terms of forecasted demand), scheduled release in the day-ahead market for the remaining days of the week, thus shifting generation forward when it is more valuable. The selection of the cut-off point was based on sensitivity analysis in which revenues were calculated using a range (85th - 99th percentile) of potential real-time price thresholds, with the 95th percentile yielding the greatest total revenue over the four years considered.

Figure 6 shows an example of how the market utilization scenario simulates a utility's participation in the day-ahead and real-time energy markets, as well as the regulation service market. First, each of the 168 hours of the week (7-day operating horizon) is ranked according to its forecasted electricity demand (e.g. the hour with the highest forecasted demand is ranked 1). Given the volume of water available for release over this period, generation in the day-ahead energy market is scheduled one hour at a time in rank order (e.g. starting with the hour ranked 1) until the volume of water is completely allocated. As an example, Figure 6 shows a week in which all hours ranked 94^{th} or higher (i.e. 1-93) are allocated water for generation in the day-ahead energy market.

Next, participation in the regulation service market is assumed for each hour in which the utility is also active in the day-ahead energy market, with the exception noted above regarding hours after 12pm on day 6 (hours 133-168). Figure 6 shows a random, negative (down) regulation signal in hour 9 (ranked 94^{th} in terms of forecasted demand). Consequently, the utility decreases generation in that hour by 10MWh, and this foregone amount is forwarded to the highest-ranked future release in the day-ahead market (i.e., hour 161, ranked 1^{st}).

Finally, on an hour-to-hour basis, the model recognizes hours in which the real-time price of electricity reaches $147.11/MWh (e.g., hour 4, ranked 148^{th}). If no generation is scheduled for that hour in the day-ahead energy market, the model borrows water from the lowest-ranked future release in the day-ahead market (i.e., hour 167, ranked 93^{th}) in order to exploit the high real-time energy price.

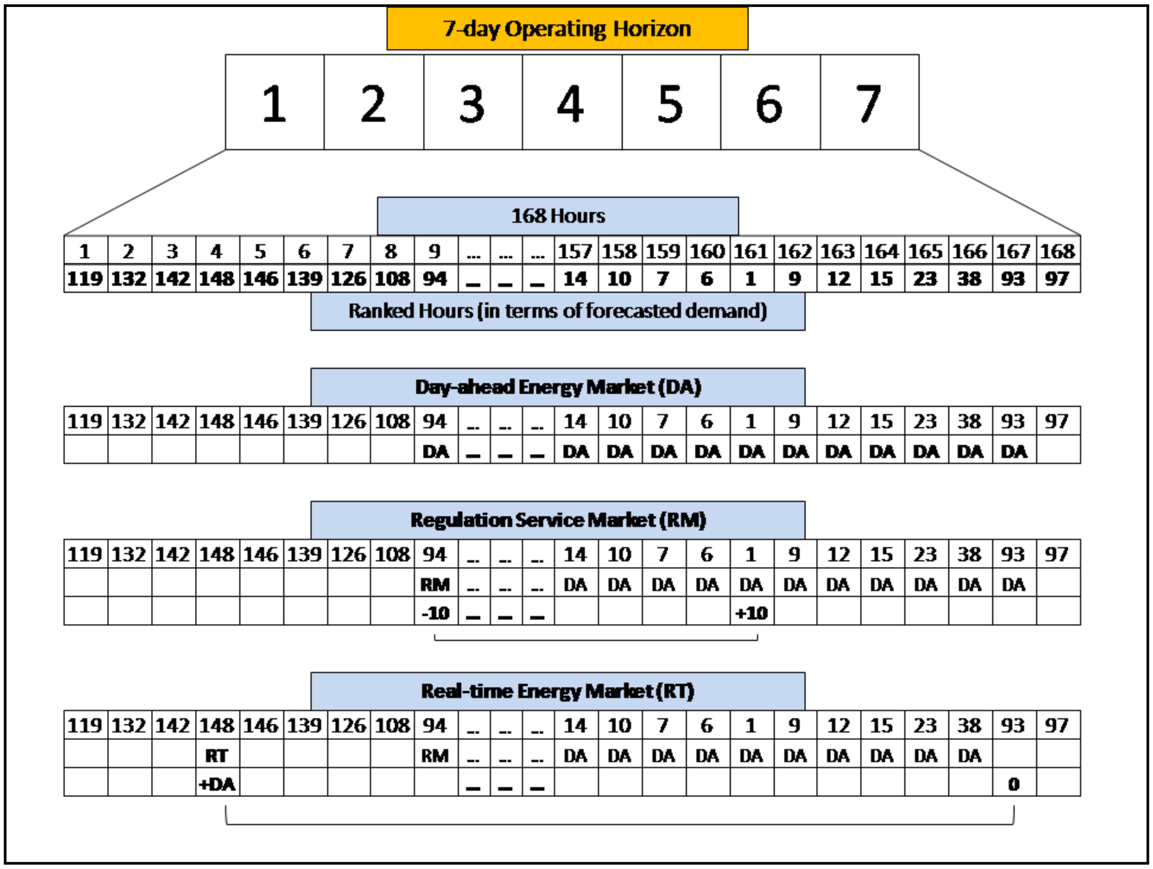

Figure 6. Example of a utility's modeled participation in multiple PJM markets.

It is important to understand the difference between revenue earned from the sale of regulation service and revenue earned from the day-ahead and real-time energy markets. As an example, if a utility sells 10MWh of regulation service in the market, and PJM requires that utility to increase (+7MWh) its net hourly generation by this amount, the utility will earn the following amount:

Day-ahead sell-offer (MWh)*Day-ahead energy price($/MWh) + 10MWh * Regulation Price($/MWh) + 7MWh*Real-time Energy Price($/MWh)

If, however, the utility is instructed to decrease net hourly generation by 7MWh, it would only earn revenue from the regulation and day-ahead energy markets:

(Day-ahead sell-offer (MWh) – 7MWh)*Day-ahead energy price ($/MWh) + 10MWh*Regulation Price ($/MWh).

In the case of decreased generation, however, the water that is not used can be saved to generate power at a future time.

Output from the power generation model is in terms of hourly flows from each of the three dams. Figure 7 shows the simulated hourly operation of Roanoke Rapids Dam under the current operations (left) and market utilization (right) scenarios. As a result of the constraint on weekly flows imposed by the USACE, the current operations and market utilization scenarios have identical volumetric flows every 7 days. However, as Figure 7 shows, hourly dam operations under the market utilization scenario reflect frequent participation in the real-time energy and regulation markets, which alters the hourly dam release schedule. In this case, there are clearly operational differences between the current operations and market utilization scenarios, and these translate into differences in both utility revenues and downstream flow regime.

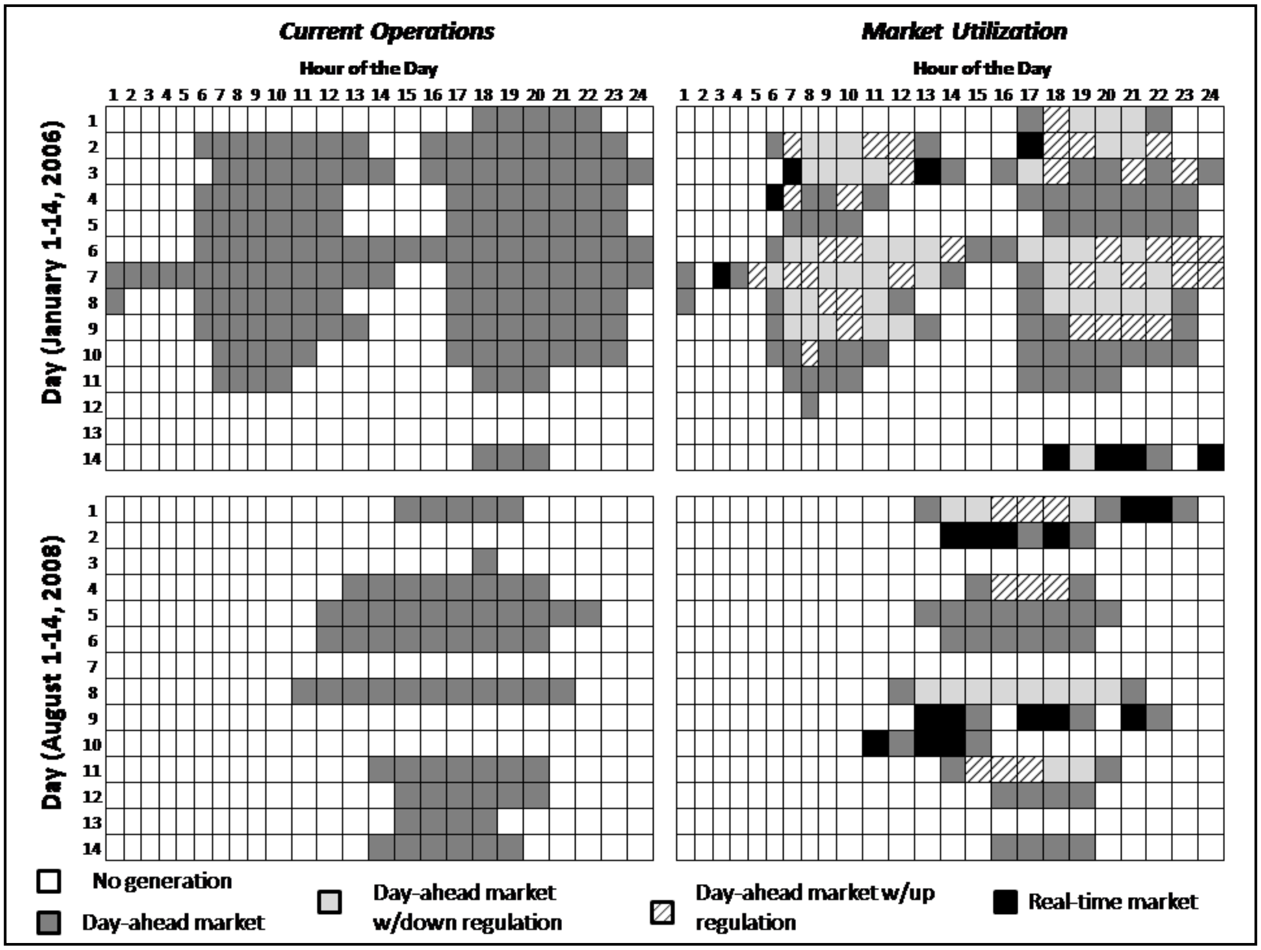

Figure 7. Modeled hourly market participation for hydropower generated at Roanoke Rapids Dam under current operations (at left) and market utilization (at right) for two periods in winter and summer.

Run-of-river

Hydrologic Model

A 'run-of-river' operating strategy at each of the three dams was designed as the second bound on dam operations (juxtaposed against market utilization, with current operations serving as an intermediary), with the expectation that it would more closely mimic unregulated flows, while still allowing Kerr Dam to fulfill its flood control and water supply responsibilities. The hydrologic model for the run-of-river operational scenario is different from those of the current operations and market utilization operational scenarios in one way: in this case, a guide curve storage constraint is used such that storage in each reservoir is always maintained at a level consistent with the respective guide curves. Figure 8 shows the guide curve for Kerr Dam.

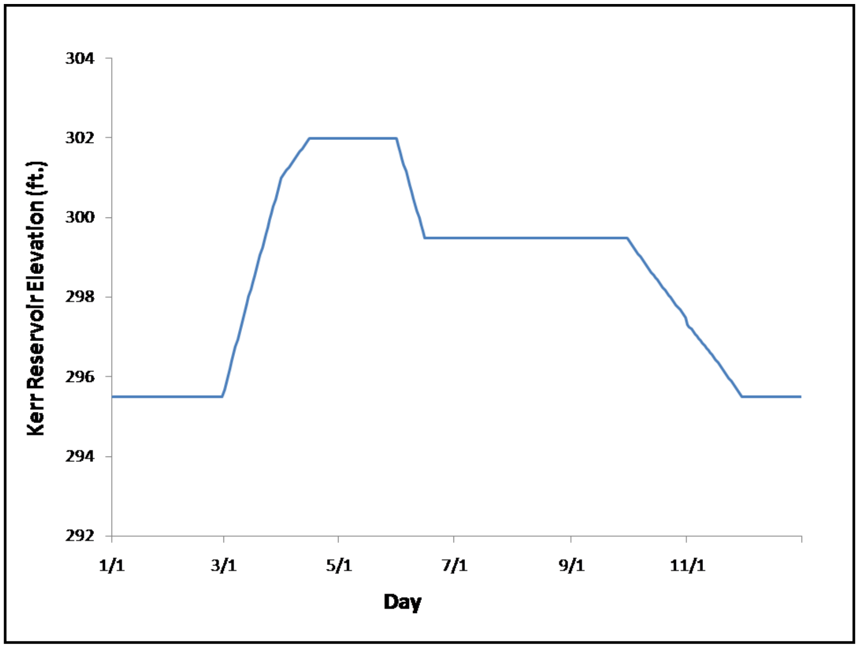

Figure 8. Guide curve for Kerr Reservoir.

Power generation model

The power generation model for the run-of-river operational scenario is simulated using a 1-day operating horizon and assuming the modeled utility participates in the day-ahead energy market only. Consequently, the dams are operated as run-of-river (i.e. outflow equals inflow) on a daily basis, and hourly releases are made in accordance with day-ahead forecasted electricity demand and, within that context, used to maximize daily generating revenues.

Unregulated Flow

Hydrologic Model

An unregulated flow scenario was also explored using the same hydrologic model, but modified to assume that all three dams had been removed and that the river exists in a naturally flowing condition. The unregulated hydrologic model simulates daily flows throughout the

Roanoke River basin for the years 1929-2009. Simulated unregulated flows were compared to historical pre-dam flows for the years 1929-1946, and this comparison revealed a good fit between modeled and observed flows for wet, normal and dry years (Figure 9). Simulated flows for the years 2006-2009 are then used to quantify differences in flow regime between the regulated scenarios (current operations, market utilization, and run-of-river) and the unregulated (or 'natural') flow regime.

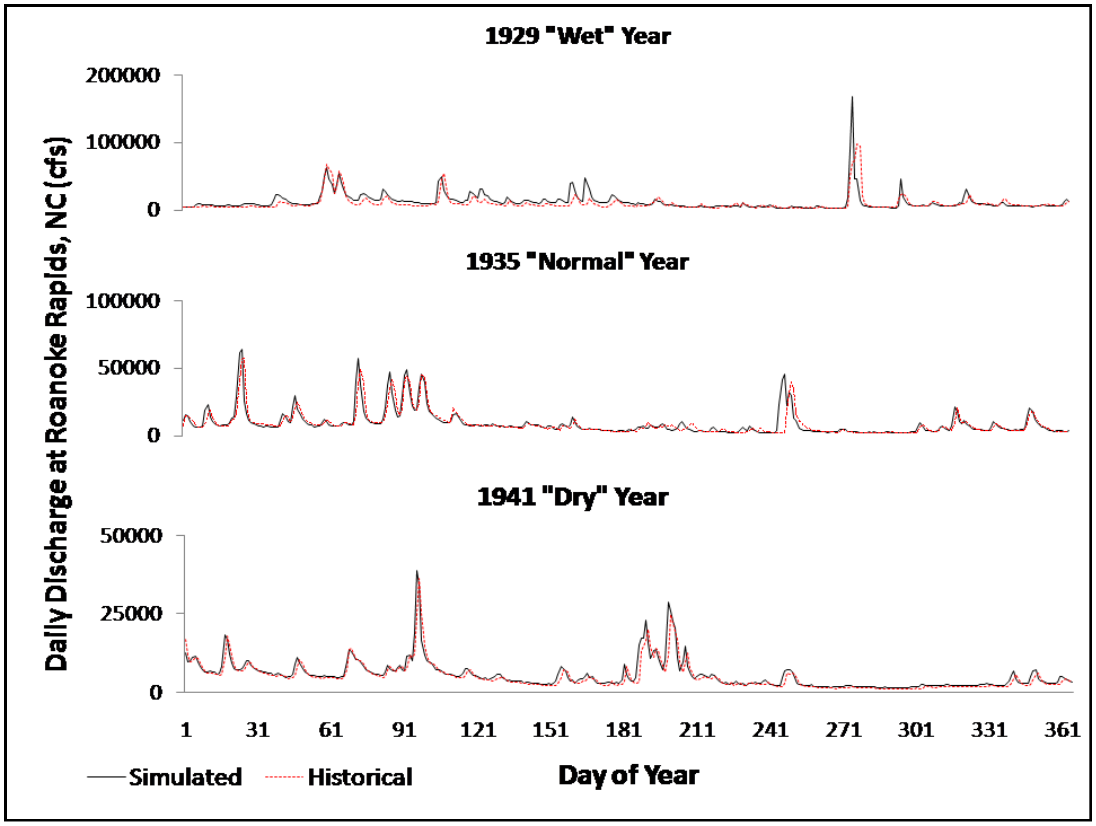

Figure 9. Validation of the unregulated hydrologic model.

Hydropower Revenue Calculation

In order to calculate hydropower revenues, hourly flow data is 'capped' at each dam's respective turbine capacity, such that no flows beyond each dam's turbine capacity generate power (or revenue). Generating efficiencies for Gaston and Roanoke Rapids Dams are assumed to be static due to their narrow reservoir storage constraints, while the generating efficiency of Kerr Dam is a function of reservoir storage at the beginning of each operating horizon. For the current operations and run-of-river scenarios, all power was assumed to be sold in the day-ahead energy market. For the market utilization scenario, revenues accruing from hours in which the utility is only participating in the day-ahead energy market are calculated in the same manner. Revenues from hours in which the utility is only participating in the real-time energy market are calculated similarly, but substituting real-time prices.

Statistical Analysis of Flow Regime

Indicators of Hydrologic Alteration (IHAs)

Indicators of Hydrologic Alteration (IHAs) were used to describe the flow regime resulting from each modeled scenario. These are a group of 32 flow statistics (Table 1), subdivided into five categories of flow: magnitude, duration, timing, frequency and rate of change. They were developed in order to quantify the degree of hydrologic alteration resulting from a particular disturbance in a river basin, such as changes in land use or a dam (Richter, 1996). Each category has been posited to have direct biological and ecological significance (Poff, 1997), such that significant changes in flow regime may lead to significant alteration of downstream riparian ecosystems. Nonetheless, despite continuing research, connecting changes in flow regime to specific biological and ecological endpoints is an ongoing challenge (Poff and Zimmerman, 2010); this work will therefore focus on evaluating changes in these IHAs relative to unregulated conditions, using these differences as a rough surrogate for environmental impacts.

Due to the widespread availability of daily flow data, the development (and use) of IHAs in previous studies has focused on characterizing flows with a maximum temporal resolution of one day. Based on the demonstrated successes of the IHA method in quantifying hydrologic changes in a river basin, the choice was made to use them in this study. Thus, it was necessary to convert output from the power generation model back to a daily resolution by summing hourly flows for each day and dividing by 24. However, this choice of time step has important implications for the results of this work, as will be discussed later.

Table 1. The 32 Indicators of hydrologic alteration (IHAs) used in this study (Richter, 1996).

Flow metric		Category
12 monthly mean flows (cfs)		magnitude, timing
1-day minimum flow (cfs)		magnitude, duration
1-day maximum flow(cfs)		magnitude, duration
1-day minimum flow date (1-365)		timing
1-day maximum flow date (1-365)		timing
3-day minimum flow(cfs)		magnitude, duration
3-day maximum flow(cfs)		magnitude, duration
7-day minimum flow(cfs)		magnitude, duration
7-day maximum flow(cfs)		magnitude, duration
30-day minimum flow(cfs)		magnitude, duration
30-day maximum flow(cfs)		magnitude, duration
90-day minimum flow(cfs)		magnitude, duration
90-day maximum flow(cfs)		magnitude, duration
# of low pulses [1]		magnitude, frequency, duration
# of high pulses [2]		magnitude, frequency, duration
Low pulse duration (days)		magnitude, frequency, duration
High pulse duration (days)		magnitude, frequency, duration
# of falls		frequency, rate of change
# of rises		frequency, rate of change
Average fall rate		frequency, rate of change
Average rise rate		frequency, rate of change

1. Defined as daily flow values <= the 25^{th} percentile of historical pre-dam flows.
2. Defined as daily flow values >= the 75^{th} percentile of historical pre-dam flows.

Analysis began with calculating the 32 IHA statistics for each individual year of the unregulated simulation (1929-2009). These unregulated values provide a base with which to compare the flow regimes of the three different operational scenarios modeled over the period 2006-2009.

Principal Components Analysis

The sheer number of IHAs can be overwhelming, and efforts to develop representative environmental flow metrics have included attempts to address the inter-correlation and redundancy among IHAs (Gao et al., 2009). From an environmental policy perspective, it may be preferable to use a smaller number of the most relevant metrics.

Therefore, principal components analysis (PCA) was used to select a subset of the most significant IHAs in a manner similar to that of Gao et al. (2009). Input data was an 81 x 32 matrix corresponding to 32 mean-centered IHA statistics for each year of the unregulated simulation (1929-2009). Decomposition of the associated covariance matrix into principal components (eigenvectors ordered by eigenvalue) yielded another matrix, the first seven columns of which are shown in Table 2. The highest loaded variable (IHA) in each eigenvector was deemed a reasonable proxy for each respective principal component. In one case (principal component 4) the second-highest loaded variable (date of 1-day maximum flow) was selected in order avoid selecting the same IHA twice. This yielded seven IHAs, which collectively were assumed to explain most (84.5%) of the variation in unregulated flow at Roanoke Rapids (Table 2). In rank order, these were: fall rate, March mean flow, low pulse duration, date of 1-day maximum flow, August, January and September mean flows. Values for these statistics were calculated for each individual year (2006-2009), under each of the three regulated scenarios (current operations, market utilization, run-of-river), as well as for observed historical flows at the stream gauge just downstream of Roanoke Rapids Dam over the same period. Annual deviations from unregulated flows (2006-2009) were then calculated.

Table 2. Selection of seven representative IHAs using principal components analysis.

	PC1	PC2	PC3	PC4	PC5	PC6	PC7
January Mean Flow	0.109746	0.17434	0.198471	-0.05594	0.037851	-0.46606	0.049393

February Mean Flow	0.149162	0.167397	0.148897	-0.1323	0.049138	-0.05676	0.053325
March Mean Flow	0.130234	0.293475	0.193882	-0.10297	0.039491	0.106933	0.037094
April Mean Flow	0.134844	0.266628	0.138303	-0.02697	0.110314	0.18184	0.076278
May Mean Flow	0.177877	0.031238	0.004293	-0.13895	0.176975	0.165702	-0.18678
June Mean Flow	0.169811	-0.09043	-0.06283	-0.05757	0.191081	0.419291	-0.19896
July Mean Flow	0.152587	-0.16508	0.104613	-0.24839	0.026181	0.242499	-0.03324
August Mean Flow	0.15017	-0.11886	-0.09583	0.074902	-0.48552	0.12467	-0.13122
September Mean Flow	0.158783	-0.01136	-0.15757	0.090434	-0.02521	-0.22842	0.516155
October Mean Flow	0.134502	-0.1146	-0.11842	0.082815	0.26355	-0.43254	0.007369
November Mean Flow	0.10732	-0.10057	-0.22688	0.174673	0.251978	-0.0689	-0.22098
December Mean Flow	0.101967	-0.03751	-0.18231	0.279663	0.356027	0.205511	-0.02314
1-day Min	0.205858	-0.25855	0.147213	-0.12686	-0.15254	-0.0756	-0.04552
1-day Max	0.213449	0.120632	-0.02644	0.298475	-0.24048	-0.01181	-0.07672
1-day Min Date	-0.08641	0.046002	0.270549	-0.12262	0.206784	-0.14414	-0.1266
1-day Max Date	0.035191	-0.18996	-0.14749	0.316541	0.095308	-0.13213	-0.3473
3-day Min	0.231318	-0.20114	0.046324	-0.19655	-0.14019	-0.04949	-0.0257
3-day Max	0.213246	0.14064	-0.03728	0.284564	-0.25942	-0.00251	-0.03618
7-day Min	0.238676	-0.15978	-0.01895	-0.22598	-0.11011	-0.05208	-0.03121
7-day Max	0.222311	0.169819	-0.05682	0.208745	-0.23288	0.043131	-0.00938
30-day Min	0.233218	-0.16538	-0.08113	-0.24124	-0.01943	-0.0788	-0.00633
30-day Max	0.219799	0.268619	0.060536	0.064257	-0.08064	0.029771	-0.04389
90-day Min	0.238161	-0.16059	-0.14513	-0.15358	0.027032	0.006122	0.08015
90-day Max	0.209981	0.292902	0.144985	-0.033	0.053792	0.08237	-0.02115
# of Low Pulses	-0.17709	0.195205	-0.26059	-0.16286	-0.09171	-0.08262	-0.23991
# of High Pulses	0.151875	0.014313	-0.28549	-0.13318	0.180339	0.137613	0.392666
Low Pulse Duration	-0.1277	-0.04743	0.311456	0.317705	0.080919	0.206882	0.222153
High Pulse Duration	0.1649	0.052361	0.306017	0.011131	0.135415	-0.17388	-0.36193
# of Falls	-0.14732	0.28071	-0.28856	-0.20057	-0.06049	-0.02229	-0.12225
# of Rises	-0.14617	0.281306	-0.28944	-0.20389	-0.06157	-0.0243	-0.12141
Fall Rate	0.256051	0.117402	-0.08064	0.074114	0.147368	-0.07758	-0.00756
Rise Rate	0.216675	0.220779	-0.20899	0.007966	0.161514	-0.0165	0.024164

Model Calibration and Sensitivity Analysis

Observed daily flows at Roanoke Rapids Dam (2006-2009) (i.e. historical current operations) were analyzed in terms of the seven IHAs selected and compared with flows from the modeled current operations scenario as a measure of model fitness. Results suggest a very reasonable fit for five of the seven metrics (Figure 8); however the model does consistently overestimate the fall rate and underestimate low pulse duration (largely the result of some assumptions that will be described more in Results). It is important to note the differences in units among the IHAs shown, as this helps mitigate concern over the large percentage error apparent for simulated low pulse duration.

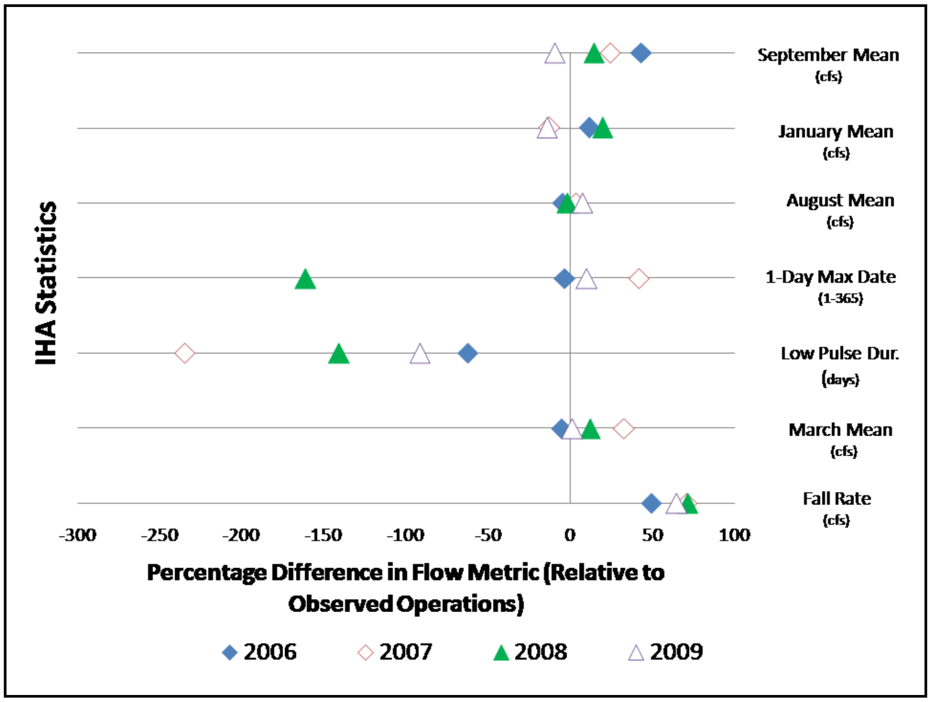

Figure 10. Comparison of modeled and observed current operations in terms of seven selected IHAs.

Sensitivity analysis was performed to quantify the relative importance of operating horizon on total annual hydropower revenues, as well as its impact on flow regime. Model simulations were run for combinations involving different operating horizons (4 or 7 days) and market participation (day-ahead energy, or both day-ahead and real-time energy, with or without regulation service) (Table 3). Deviation from unregulated flows is quantified as root mean squared difference between regulated and unregulated flows at Roanoke Rapids Dam.

Results show that the average impacts of moving from a 4- to 7-day operating horizon are a 15.4% increase in deviation from unregulated flows (range: -94.1% to +59.4%) and a 1.1%

increase in cumulative revenue (range: +0.7% to +2.9%). This suggests that length of operating horizon has a fairly small potential to alter either a utility's revenue or downstream flow regime.

Table 3. Sensitivity analysis scenarios are underlined.

		Market Participation			
		Day-ahead	Day-ahead w/Regulation	Day-ahead and Real-time	Day-ahead and Real-time w/Regulation
Operating Horizon	4-day	Current Operations	**RM4**	**RT4**	**RMRT4**
	7-day	**7**	**RM7**	**RT7**	Market Utilization

Results and Discussion

In all years the market utilization scenario results in the highest hydropower revenues (2006-2009), followed by the current operations scenario and then the run-of-river scenario (Table 4). The unregulated scenario assumes no dam and thus no hydropower generation. The cumulative difference in revenue between the run-of-river scenario and the current operations and market utilization scenario is a product of the run-of-river scenario's guide curve storage constraint and 1-day operating horizon. These two constraints, respectively, result in significantly more 'spilling' (releases larger than the turbine capacity of the dams) and more frequent generation during periods of relatively low electricity demand (and price).

The difference in cumulative revenue between the current operations and market utilization scenarios is primarily a reflection of the differences in market participation (day-ahead energy only versus day-ahead and real-time energy markets with regulation service). The current operations scenario generates $260.4M over four years selling energy in the day-ahead energy market only, while the market utilization scenario generates $279.5M over the same period selling energy in the day-ahead ($231.1M) and real-time ($45.8M) markets, as well as the regulation service market ($2.6M).

Table 4. Generation and revenue calculations for modeled scenarios. Seasons defined as follows: Spring (Mar.-May), Summer (June-Aug.), Fall (Sep.-Nov.) and Winter (Dec.-Feb.).

Current Operations			Revenue ($M)				
Year	Hydrologic Condition	Generation[3] (GWh)	Spring	Summer	Fall	Winter	Annual
2006	Normal	973.18	6.82	21.45	18.76	21.81	68.83
2007	Normal	810.08	22.26	15.23	8.22	21.59	67.30
2008	Dry	639.29	22.17	21.07	8.97	15.69	67.89
2009	Normal	1135.18	13.04	11.68	8.72	22.93	56.37
	Total	3557.73	64.28	69.43	44.67	82.01	**260.39**
Market Utilization			**Revenue ($M)**				
Year	Hydrologic Condition	Generation[3] (GWh)	Spring	Summer	Fall	Winter	Annual
2006	Normal	973.21	7.94	22.66	19.18	24.01	73.79
2007	Normal	809.44	23.69	17.81	9.12	24.45	75.06
2008	Dry	638.14	24.62	21.70	9.52	17.03	72.87
2009	Normal	1131.21	13.45	11.94	8.79	23.57	57.75
	Total	3552.01	69.69	74.11	46.62	89.06	**279.48**
Run-of-river			**Revenue ($M)**				
Year	Hydrologic Condition	Generation[3] (GWh)	Spring	Summer	Fall	Winter	Annual
2006	Normal	944.95	5.30	17.36	19.55	18.79	60.99
2007	Normal	731.54	18.86	9.45	9.42	18.43	56.15
2008	Dry	629.76	20.40	15.75	10.43	13.27	59.84
2009	Normal	1064.76	12.29	8.87	8.87	20.23	50.26
	Total	3371.01	56.85	51.42	48.26	70.71	**227.24**

3. 1 GWh = 1000 MWh.

Figure 11 plots annual hydropower revenues against deviation from the unregulated flow regime for each operational scenario (2006-2009). Deviation is quantified as root mean squared difference between modeled flows and unregulated flows at Roanoke Rapids Dam. The IHA depicted in Figure 11 (fall rate) is shown as an example due to its high ranking of importance among IHAs selected. Movement away from the origin along the y-axis signifies increased revenue. Along the x-axis, movement away from the origin signifies greater disparity between regulated (i.e. current operations, market utilization, and run-of-river) and unregulated flows (an x-value of zero would mean the regulated scenario perfectly mimics unregulated flow with regard to fall rate).

Analysis of the three modeled scenarios (current operations, market utilization, run-of-river) in 2D space is critical to understanding the influence of de-regulated electricity markets on hydropower generation and downstream flow regime. A positive relationship between hydropower revenues and deviation from unregulated flow implies a tradeoff between downstream environmental quality and hydropower revenue. While this tradeoff is clearly present in some of our results (e.g. data for 2006 in Figure 11), in some cases the trend is the opposite (e.g. data for 2006 and 2008 in Figure 12), showing that operational scenarios generating more hydropower revenue occasionally replicate unregulated flow better than the run-of-river scenario.

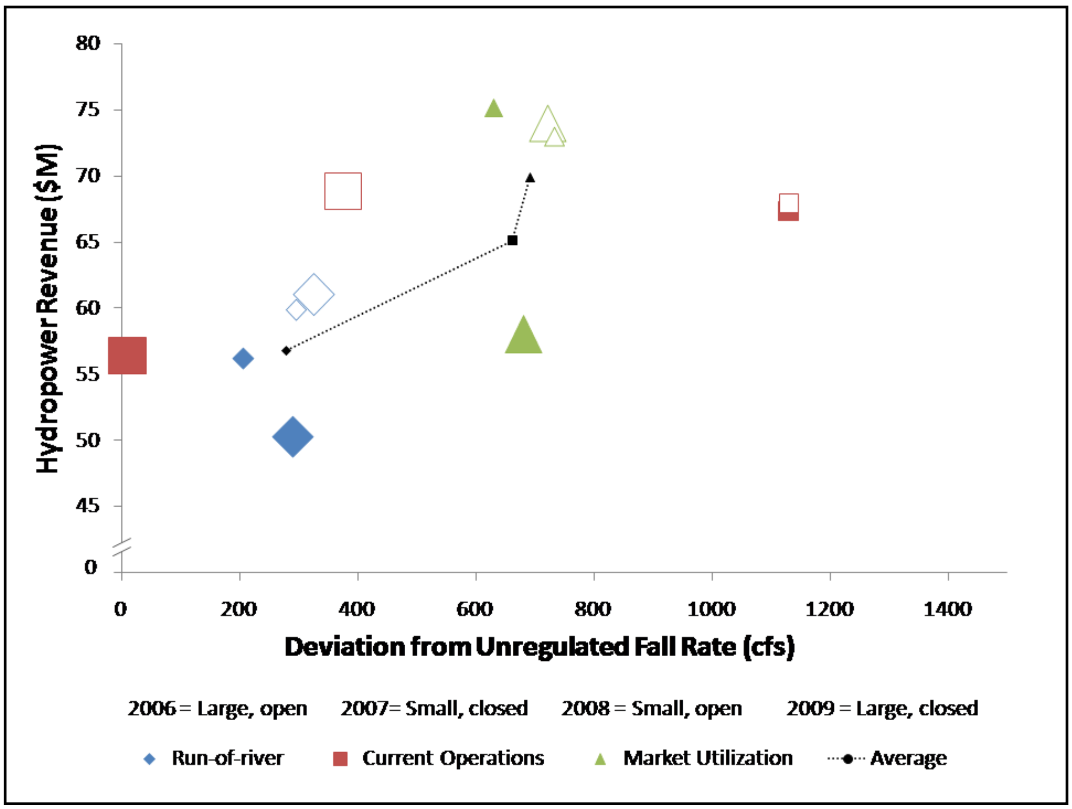

Figure 11. Hydropower revenues vs. deviation from unregulated fall rate.

Figure 12 plots annual hydropower revenues against deviation from the unregulated flow regime in terms of March mean flow, another high ranking IHA. In this case, there is an overall negative relationship between revenue and deviation for all four years.

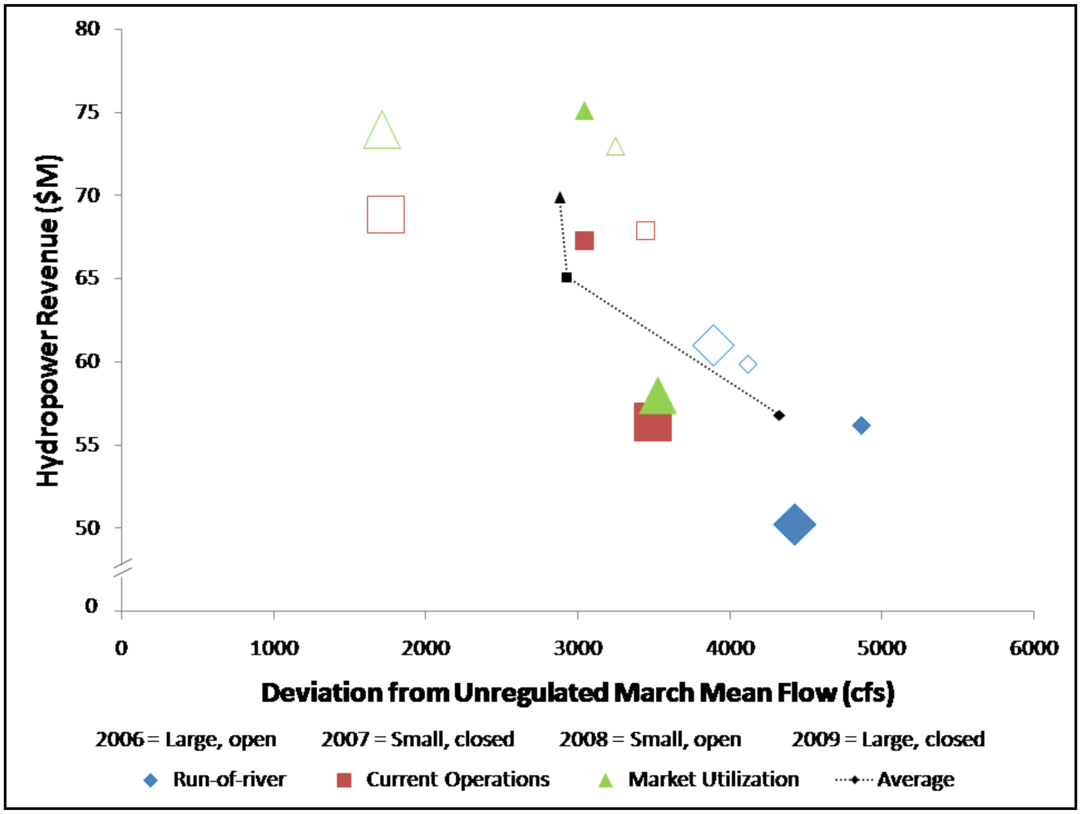

Figure 12. Hydropower revenues vs. deviation from unregulated March mean flow.

Results indicate that for six out of the seven IHAs considered, one of these two general relationships holds for at least three years over the period 2006-2009. However, only three IHAs (March mean flow, 1-day maximum flow date and September mean flow) demonstrate a consistent relationship between hydropower revenue and deviation from the natural flow regime over all four years. The variable nature of the relationship between hydropower revenues and deviation from the unregulated flow regime appears to be somewhat influenced by year, which suggests that sub-annual hydrologic conditions are an important factor.

Based on the nature of 3-scenario ordinary least squares regressions (plotted by IHA and year), a fairly consistent, positive relationship between revenue and deviation from unregulated flows exists for the following IHAs: fall rate, low pulse duration and 1-day maximum flow date, as well as January and September mean flows. This trend reverses for March mean flow, for which the most lucrative hydropower scenarios (current operations and market utilization) result in the smallest deviations from the natural flow regime.

Table 5 shows calculated values of the seven IHAs selected for each scenario, along with annual revenue and deviation from unregulated flows at Roanoke Rapids Dam, for the period 2006-2009. Several general trends are apparent in these results. First, when compared to the current operations and market utilization scenarios, the run-of-river scenario results in less deviation from unregulated flows most (71.4%) of the time. However, only 55.0% of the time is this improvement greater than the difference between run-of-river and unregulated flows. Together, these trends suggest that the run-of-river scenario is only effective at significantly reducing deviation from unregulated flows 39.3% of the time. Otherwise, pursuing such a policy either results in relatively minor improvements or a flow regime more divergent from unregulated flows.

In addition, detailed consideration was given to the impact of the market utilization scenario on revenue and downstream flow regime relative to current operations. In all years the market utilization scenario results in greater revenue than the current operations scenario. Half of the time, it also results in greater deviation from pre-dam flows, relative to current operations. Nonetheless, the scale of these differences is crucial to their implications. With the exception of one extreme case where the percentage increase in deviation is very large (i.e. changes to fall rate in 2009), across all IHAs (for the period 2006-2009) the average percentage change in deviation attributable to the market utilization scenario is +12.6% relative to current operations, compared to an average change in revenue of +7.1% (Table 6).

Table 5. Results from modeled scenarios.

	2006 (Normal Hydrologic Year)			2008 (Dry Hydrologic Year)		
	Current Operations	Market Utilization	Run-of-river	Current Operations	Market Utilization	Run-of-river
Fall Rate	2835.6	2490.1	3537.1	3138.9	2741.6	2302.8
(Deviation)	*376.0*	*721.5*	*325.5*	*1131.1*	*733.9*	*295.1*
March Mean Flow	2477.6	2505.4	325.0	2841.8	3033.9	2165.8
(Deviation)	*1735.4*	*1707.6*	*3888.0*	*3440.8*	*3248.7*	*4116.8*
Low Pulse Duration	2.1	1.9	4.4	2.3	2.3	4.0
(Deviation)	*0.1*	*0.3*	*2.2*	*2.9*	*2.9*	*1.2*
1-Day Max Date	328.0	328.0	329.0	137.0	137.0	348.0
(Deviation)	*1.0*	*1.0*	*0.0*	*211.0*	*211.0*	*0.0*
August Mean Flow	3460.2	3343.2	2378.4	2922.8	3200.1	2273.5
(Deviation)	*573.0*	*456.0*	*508.7*	*199.5*	*476.8*	*449.8*
January Mean Flow	8418.9	8317.6	8915.2	3461.1	3480.9	3030.6
(Deviation)	*979.3*	*1080.6*	*483.0*	*200.4*	*180.6*	*630.8*
Sept. Mean Flow	5799.6	5799.6	6811.3	3890.2	3590.7	5265.7
(Deviation)	*998.4*	*998.4*	*13.3*	*1560.7*	*1860.2*	*185.2*
Revenue ($M)	68.8	73.8	42.8	67.9	72.9	44.5
	2007 (Normal Hydrologic Year)			2009 (Normal Hydrologic Year)		
Fall Rate	3313.3	2814.0	2389.5	3194.3	2502.8	3474.4
(Deviation)	*1130.4*	*631.0*	*206.6*	*10.4*	*681.0*	*290.6*
March Mean Flow	10319.7	10321.5	8495.7	8435.8	8403.1	7500.9
(Deviation)	*3041.4*	*3039.6*	*4865.4*	*3491.6*	*3524.3*	*4426.5*
Low Pulse Duration	2.4	2.2	4.6	2.2	2.5	2.7
(Deviation)	*6.4*	*6.7*	*4.3*	*1.9*	*1.6*	*1.4*
1-Day Max Date	12.0	12.0	4.0	365.0	365.0	319.0
(Deviation)	*8.0*	*8.0*	*0.0*	*46.0*	*46.0*	*0.0*
August Mean Flow	3439.7	3280.1	1167.1	3457.2	3485.3	2313.5
(Deviation)	*1473.9*	*1314.3*	*798.7*	*598.6*	*626.7*	*545.1*
January Mean Flow	15750.0	15717.8	16025.4	6702.5	6587.7	6755.2
(Deviation)	*745.0*	*777.2*	*469.7*	*573.6*	*688.4*	*521.0*
Sept. Mean Flow	3038.4	3019.7	1771.0	3151.6	3052.5	1630.2
(Deviation)	*773.4*	*754.6*	*494.1*	*1143.3*	*1044.3*	*378.1*
Revenue ($M)	67.3	75.1	47.7	56.4	57.8	68.5

Table 6. Data trends for modeled scenarios. Impacts of run-of-river and market utilization are relative to current operations.

	Fall Rate	March Flow	Low Pulse Duration	1-Day Max Date	August Flow	January Flow	September Flow
Nature of 3-Scenario OLS ($ vs. Deviation)							
2006	+	-	-	+	∞	+	+
2007	+	-	+	+	+	+	+
2008	+	-	+	+	-	-	+
2009	0	-	+	+	+	+	+
Impact of Run-of-river Policy on Deviation							
2006	-13.4%	124.0%	2319.0%	-100.0%	-11.2%	-50.7%	-98.7%
2007	-81.7%	60.0%	-33.4%	-100.0%	-45.8%	-37.0%	-36.1%
2008	-73.9%	19.6%	-58.7%	-100.0%	125.5%	214.8%	-88.1%
2009	2680.6%	26.8%	-28.0%	-100.0%	-8.9%	-9.2%	-66.9%
Impact of Market Utilization on Deviation							
2006	91.9%	-1.6%	203.1%	0.0%	-20.4%	10.3%	0.0%
2007	-44.2%	-0.1%	3.8%	0.0%	-10.8%	4.3%	-2.4%
2008	-35.1%	-5.6%	-0.7%	0.9%	139.0%	-9.9%	19.2%
2009	6417.7%	0.9%	-16.5%	0.0%	4.7%	20.0%	-8.7%

Sensitivity analysis was also performed to quantify the relative importance of choices related to market participation on total annual hydropower revenues, as well as their respective impacts on flow regime. Results show that participation in the real-time energy market yields the highest average increase in revenue (4.7%), adding about $12.42M to cumulative revenue (2006-2009) when independently incorporated into the current operations scenario. Participation in the regulation service market yields an average increase of (1.2%), adding about $2.75M when independently incorporated into the current operations scenario.

The demonstrated individual impacts of both these variables on flow regime are typically quite small relative to total deviation from unregulated flows. Participation in the real-time energy market results in an average increase in deviation from unregulated flows of 9.8% (median: 0.0%; range: -91.6% to +468.4%), while regulation services results in an average increase in deviation of 44.3% (median: 0.0%; range: -61.5% to +4187.2%). Normal probability plots indicate that results from both these sensitivity analyses are generally distributed normally, so Grubbs' test for outliers was used to eliminate 12 and 19 outliers (out of 112 data points) for tests of the real-time and regulation service markets, respectively. Following this removal, the average impact of regulation service on deviation was found to be -.95%; similarly, the average impact of participation in the real-time market was then found to be +.19%.

The results of this study suggest that dam operational policies designed to either: 1) minimize impacts on downstream flow regime (run-of-river); or 2) realize additional revenue generating possibilities in de-regulated electricity markets (market utilization), have modest potential to change flows relative to an unregulated scenario, particularly the latter.

The general trend between hydropower revenue and deviation from unregulated flows appears to be positive (higher revenue leads to more deviation), albeit somewhat variable across the seven IHAs used in this study, as well as dependant on the year in question (2006-2009). Implementing a run-of-river policy frequently results in flow regimes that mimic unregulated flows a little better than current operations, but these improvements appear to be quite small a majority of the time and come at the costs of substantial foregone hydropower revenue. When comparing the current operations and market utilization scenarios, in most cases the scale of the differences in flow regime between the two is again quite small, while the added revenue generating potential of the latter is significant (mostly a product of participation in the real-time energy market).

With the qualification that these results reflect the use of IHA statistics on a daily time-step, they may recommend future discussions of hydroelectric dams and basin management being framed more explicitly around whether the dams should remain in place. If so, results from this study suggest that policies put in place to mitigate dams' effects on flow regime may have marginal impacts and come at the cost of significant foregone hydropower revenue.

Interpreting the results of this study depends on the ability of the IHAs (Table 1) to measure hydrologic disturbance in a biologically and ecologically significant way. The use of IHAs in several previous studies has established this method as an effective way to gauge the level of hydrologic alteration following a disturbance (e.g. a dam or land use change). In this case, even when analyzing flow data in terms of a smaller subset of IHAs determined to be most relevant, this study finds a sometimes inconsistent relationship to exist between hydropower revenues and flow regime, one that depends on which IHA, year, and aspects of de-regulated electricity markets are under consideration. Also, similar to previous research, this study was conducted using a maximum temporal resolution of one day, largely due to current IHAs' being linked to daily flows; but perhaps daily patterns do not fully capture the potential for environmental impact. Due to the hourly variation of market prices, de-regulated electricity markets such as PJM may have the potential to significantly change current hydropower operations on an hourly basis. Consequently, we would expect some of the effects of these sorts of markets on flow regime to be more evident when analyzed on an hourly time step. As such, selection of a temporal resolution for both modeling and flow metrics may have important implications for the analysis and any resulting recommendations.

Conclusion

Perhaps the most concrete conclusion that can be drawn from this study is that hydropower utilities may be able to significantly increase revenue by participating in the real-time energy market; the same appears true, though to a lesser degree, for participation in the regulation service market, as well as the development of enhanced demand forecasting techniques (greater operating horizon). When viewed within the broader context of the range of operating scenarios considered in this study, our results do not suggest that pursuing this revenue would significantly change flow regime relative to current operations (nor, in most cases, run-of-river flows), when compared to unregulated flows. However, this conclusion in particular is tied to our use of IHAs with a maximum temporal resolution of one day. It is also made with the caveat that a longer simulation period (made possible by longer records of historical market data) would significantly strengthen our ability to describe the potential impacts of de-regulated electricity markets on hydropower generation and downstream flow regime.

Future Work

This study has laid the groundwork for further investigation of the impacts of electricity markets on flow regime downstream from hydroelectric dams. However, before more research is done on this topic in the Roanoke River basin, model assumptions that resulted in errors in the simulated flows (with respect to observed values) must be addressed. The most likely cause of these errors is the hydrologic model, which is most effective at simulating reservoir operations during wet and dry periods (as opposed to normal years, like 2006, 2007 and 2009). In addition, the model may not be incorporating certain basin water supply users, which may be responsible for the overestimation of flows in certain months.

Future research of this kind should also entail the development of alternative IHAs that take into account hourly changes in flow regime, and efforts should be made to investigate the potential connection between these hourly changes in flow regime and any tangible biological or ecological effects. In addition, future work should address the potential liabilities of using such short timescale (2006-2009) for modeled scenarios. Methods for generating synthetic records of stochastic hydrological inputs, as well as market inputs (e.g. electricity prices and demand) may facilitate performing this type of analysis over a longer period. Furthermore, a probabilistic decision making algorithm may create a more realistic choice process on the part of the modeled hydropower utility. These model enhancements, combined with added consideration of the potential influences of climate change, the likely increased use of intermittent renewable energy sources by energy utilities, as well as other ancillary services markets, should set the stage for interesting future developments in the management of hydrological and environmental assets of a river basin. Research of this kind may be a critical step towards developing long-term effective strategies that incorporate the dynamic water demands of a diverse array of human and environmental users.

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Appendix A: Supplementary Tables and Figures

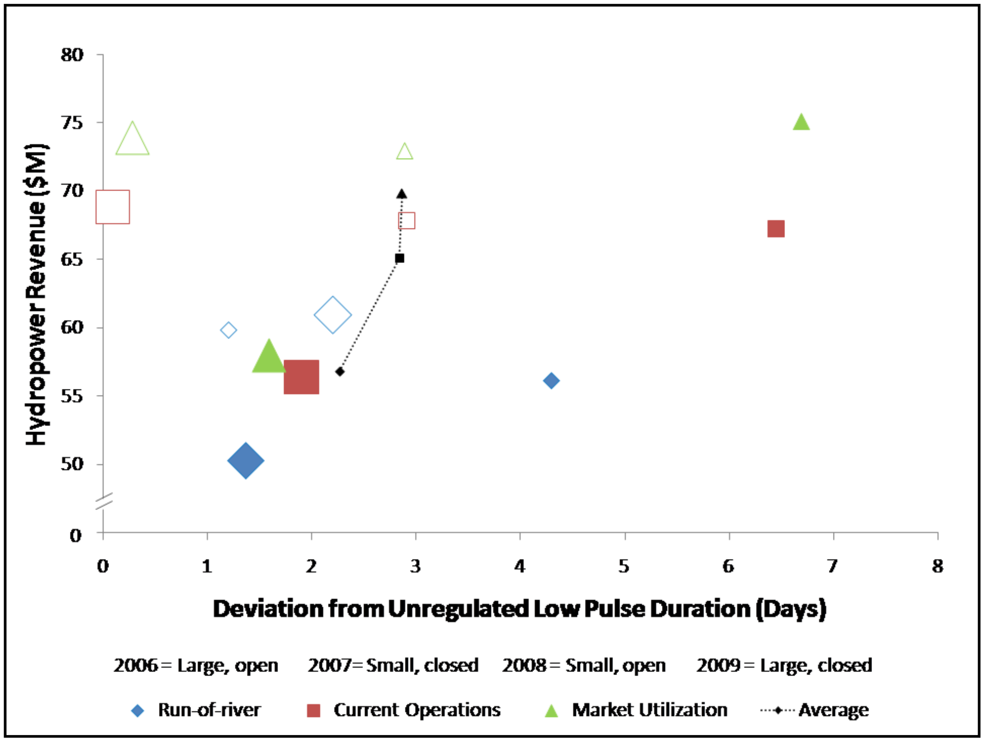

Figure 13. Hydropower revenue vs. deviation from unregulated low pulse duration (days).

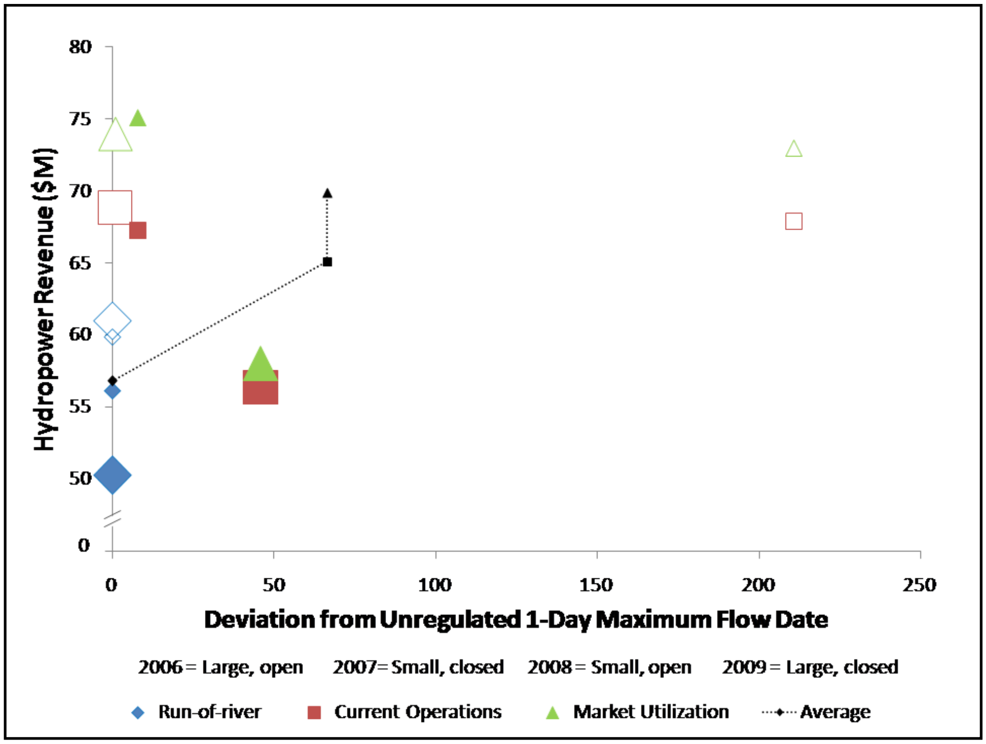

Figure 14. Hydropower revenue vs. deviation from unregulated 1-day maximum flow date.

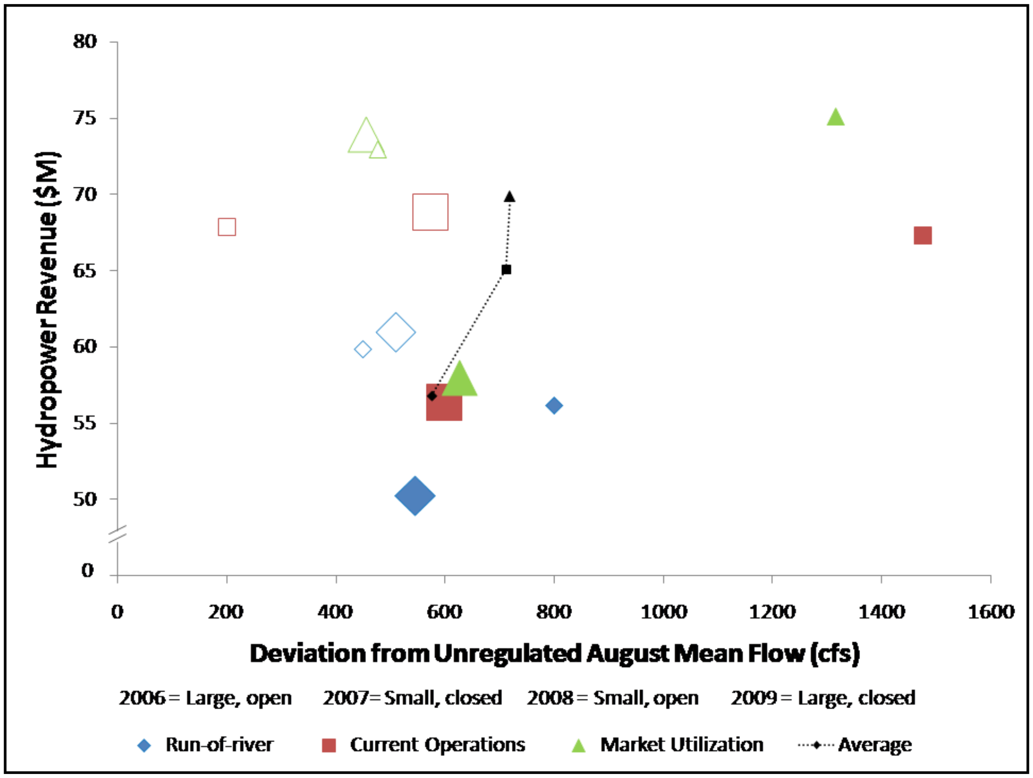

Figure 15. Hydropower revenue vs. deviation from unregulated August mean flow.

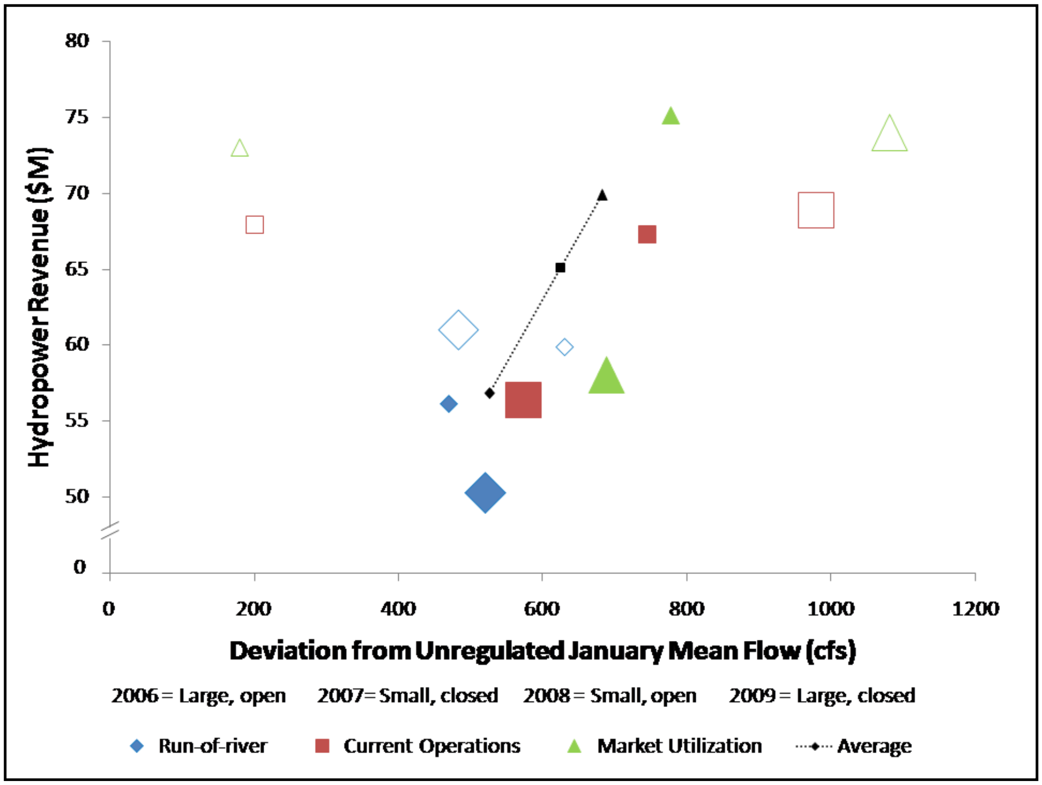

Figure 16. Hydropower revenue vs. deviation from unregulated January mean flow.

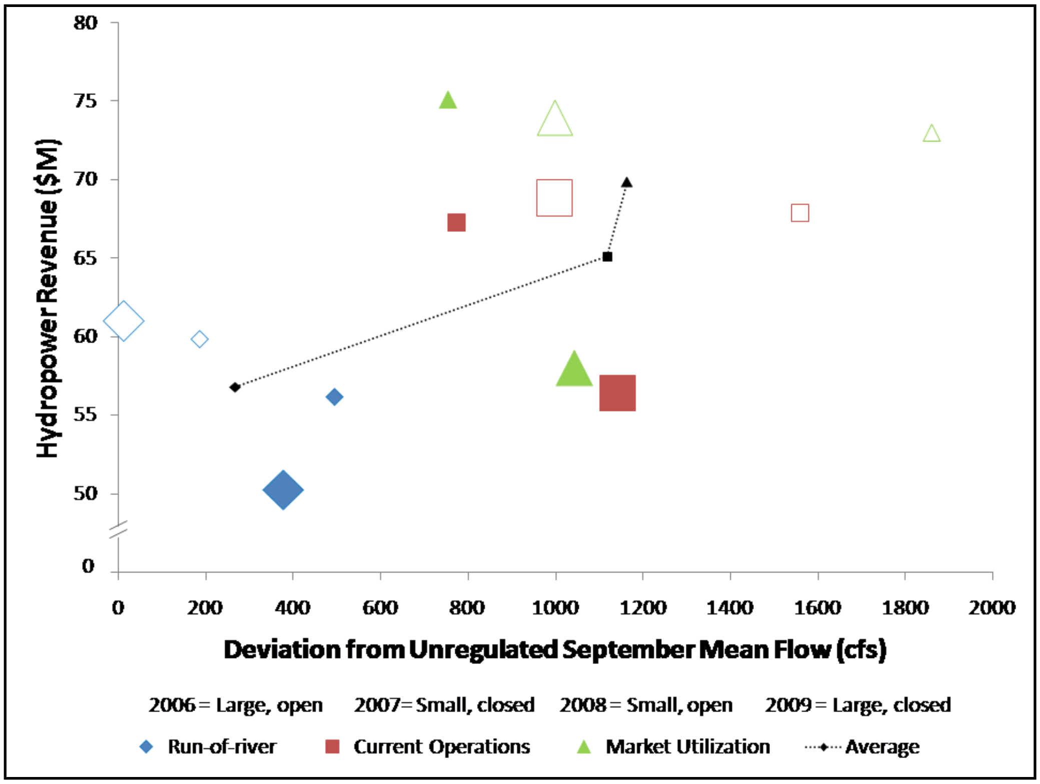

Figure 17. Hydropower revenue vs. deviation from unregulated September mean flow.

Table 7. 2006 results from the sensitivity analysis.

2006	Sensitivity Analysis					
	7	RM4	RT4	RM7	RT7	RMRT4
Fall Rate *(Deviation)*	**3011.0** *200.6*	**2697.5** *514.1*	**2925.3** *286.3*	**2392.3** *819.3*	**3194.8** *16.8*	**2740.3** *471.3*
March Mean Flow *(Deviation)*	**2477.5** *1735.6*	**2475.8** *1737.2*	**2477.6** *1735.4*	**2481.0** *1732.0*	**2500.6** *1712.5*	**2475.8** *1737.2*
Low Pulse Duration *(Deviation)*	**2.1** *0.1*	**2.1** *0.1*	**2.0** *0.2*	**2.1** *0.0*	**1.9** *0.2*	**2.0** *0.2*
1-Day Max Flow *(Deviation)*	**328.0** *1.0*	**328.0** *1.0*	**328.0** *1.0*	**328.0** *1.0*	**328.0** *1.0*	**328.0** *1.0*
August Mean Flow *(Deviation)*	**3460.2** *573.0*	**3468.4** *581.2*	**3390.3** *503.1*	**3463.3** *576.1*	**3338.3** *451.2*	**3401.0** *513.9*
January Mean Flow *(Deviation)*	**8325.3** *1072.9*	**8413.6** *984.6*	**8418.9** *979.3*	**8313.8** *1084.4*	**8322.9** *1075.3*	**8413.6** *984.6*
September Mean Flow *(Deviation)*	**5799.6** *998.4*	**5799.6** *998.4*	**5799.6** *998.4*	**5799.6** *998.4*	**5799.6** *998.4*	**5799.6** *998.4*
Revenue ($M)	**69.4**	**69.6**	**72.0**	**70.5**	**72.9**	**72.7**

Table 8. 2007 results from the sensitivity analysis.

2007	Sensitivity Analysis					
	7	RM4	RT4	RM7	RT7	RMRT4
Fall Rate	**3616.1**	**3236.4**	**3384.1**	**2734.9**	**3575.9**	**3238.0**
(Deviation)	*1433.1*	*1053.4*	*1201.2*	*552.0*	*1392.9*	*1055.1*
March Mean Flow	**10297.6**	**10322.5**	**10363.4**	**10298.6**	**10334.0**	**10378.8**
(Deviation)	*3063.5*	*3038.6*	*2997.7*	*3062.5*	*3027.1*	*2982.3*
Low Pulse Duration	**2.4**	**2.4**	**2.1**	**2.5**	**2.1**	**2.0**
(Deviation)	*6.5*	*6.4*	*6.8*	*6.4*	*6.8*	*6.8*
1-Day Max Flow	**12.0**	**12.0**	**12.0**	**12.0**	**12.0**	**12.0**
(Deviation)	*8.0*	*8.0*	*8.0*	*8.0*	*8.0*	*8.0*
August Mean Flow	**3314.9**	**3450.0**	**3419.8**	**3317.4**	**3275.9**	**3426.9**
(Deviation)	*1349.1*	*1484.2*	*1454.0*	*1351.6*	*1310.1*	*1461.1*
January Mean Flow	**15693.8**	**15763.1**	**15751.0**	**15699.4**	**15694.5**	**15764.1**
(Deviation)	*801.2*	*731.9*	*744.0*	*795.6*	*800.5*	*731.0*
September Mean Flow	**3099.0**	**3055.1**	**3030.0**	**3112.6**	**3024.7**	**3030.0**
(Deviation)	*833.9*	*790.0*	*764.9*	*847.5*	*759.6*	*764.9*
Revenue ($M)	**67.8**	**68.0**	**72.5**	**69.0**	**74.0**	**73.0**

Table 9. 2008 results from the sensitivity analysis.

2008	Sensitivity Analysis					
	7	RM4	RT4	RM7	RT7	RMRT4
Fall Rate	**3337.6**	**3129.0**	**2971.1**	**2611.0**	**3424.5**	**2994.2**
(Deviation)	*1329.9*	*1121.3*	*963.3*	*603.2*	*1416.8*	*986.5*
March Mean Flow	**2805.3**	**2846.8**	**2978.2**	**2807.8**	**3032.6**	**2981.4**
(Deviation)	*3477.3*	*3435.8*	*3304.4*	*3474.8*	*3250.0*	*3301.2*
Low Pulse Duration	**2.4**	**2.2**	**2.1**	**2.4**	**2.4**	**2.2**
(Deviation)	*2.8*	*3.0*	*3.1*	*2.9*	*2.9*	*3.0*
1-Day Max Flow	**137.0**	**137.0**	**137.0**	**135.0**	**137.0**	**137.0**
(Deviation)	*211.0*	*211.0*	*211.0*	*213.0*	*211.0*	*211.0*
August Mean Flow	**3025.6**	**2922.8**	**3080.6**	**3023.8**	**3200.6**	**3080.6**
(Deviation)	*302.3*	*199.5*	*357.3*	*300.5*	*477.3*	*357.3*
January Mean Flow	**3461.1**	**3460.6**	**3430.6**	**3460.8**	**3474.0**	**3430.1**
(Deviation)	*200.4*	*200.9*	*230.8*	*200.7*	*187.5*	*231.3*
September Mean Flow	**3783.9**	**3890.2**	**3727.1**	**3785.8**	**3590.1**	**3727.1**
(Deviation)	*1666.9*	*1560.7*	*1723.8*	*1665.1*	*1860.7*	*1723.8*
Revenue ($M)	**68.2**	**68.5**	**71.4**	**69.3**	**71.9**	**71.9**

Table 10. 2009 results from the sensitivity analysis.

2009	Sensitivity Analysis					
	7	RM4	RT4	RM7	RT7	RMRT4
Fall Rate *(Deviation)*	**3291.3** *107.5*	**3024.6** *159.2*	**3166.2** *17.6*	**2544.5** *639.4*	**3228.0** *44.2*	**2981.7** *202.2*
March Mean Flow *(Deviation)*	**8398.8** *3528.6*	**8430.4** *3497.0*	**8435.8** *3491.6*	**8389.8** *3537.5*	**8398.8** *3528.6*	**8430.4** *3497.0*
Low Pulse Duration *(Deviation)*	**2.3** *1.7*	**2.1** *2.0*	**2.3** *1.8*	**2.3** *1.8*	**2.6** *1.5*	**2.3** *1.8*
1-Day Max Flow *(Deviation)*	**366.0** *47.0*	**365.0** *46.0*	**365.0** *46.0*	**365.0** *46.0*	**366.0** *47.0*	**365.0** *46.0*
August Mean Flow *(Deviation)*	**3476.4** *617.8*	**3458.3** *599.6*	**3457.2** *598.6*	**3479.7** *621.1*	**3476.4** *617.8*	**3458.3** *599.6*
January Mean Flow *(Deviation)*	**6603.7** *672.4*	**6701.2** *574.9*	**6702.5** *573.6*	**6597.6** *678.5*	**6603.7** *672.4*	**6701.2** *574.9*
September Mean Flow *(Deviation)*	**3052.5** *1044.3*	**3151.6** *1143.3*	**3151.6** *1143.3*	**3052.5** *1044.3*	**3052.5** *1044.3*	**3151.6** *1143.3*
Revenue ($M)	**56.6**	**57.1**	**56.9**	**57.4**	**57.0**	**57.4**

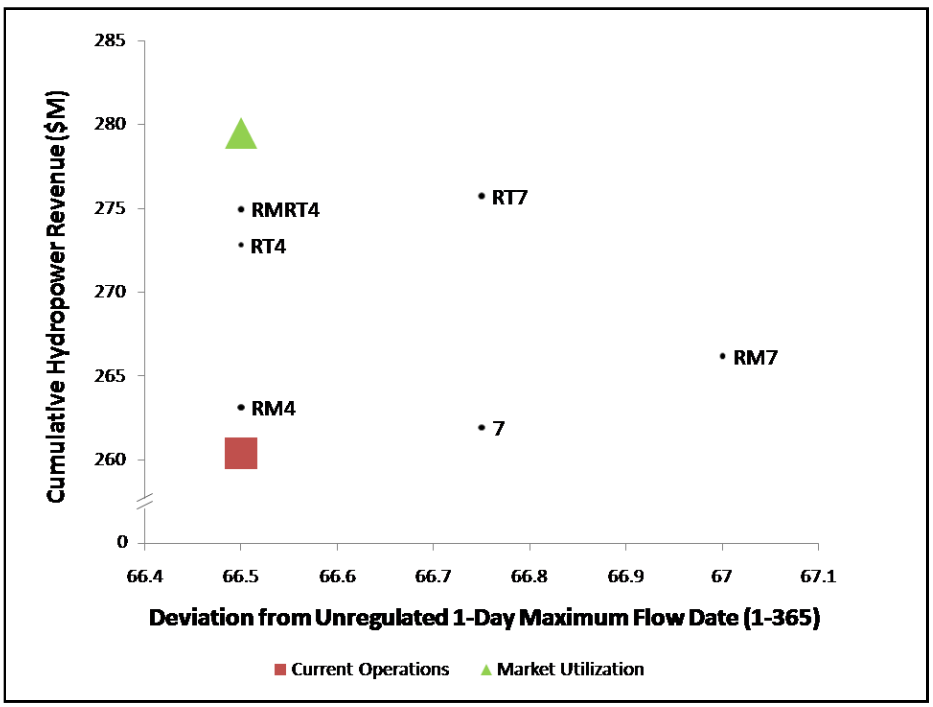

Figure 18. Results from the sensitivity analysis in terms of 1-day maximum flow date.

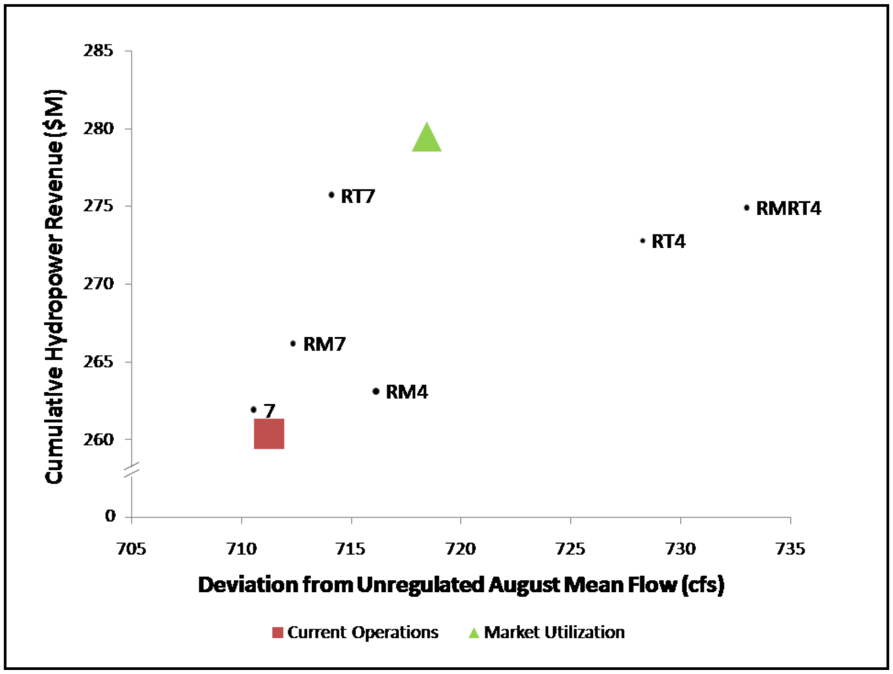

Figure 19. Results from the sensitivity analysis in terms of August mean flow.

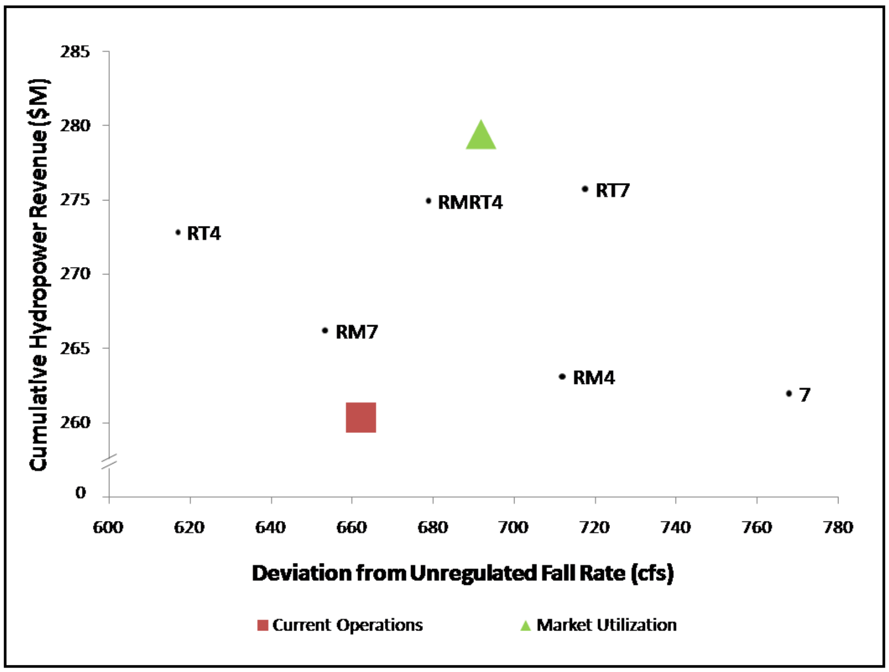

Figure 20. Results from the sensitivity analysis in terms of fall rate.

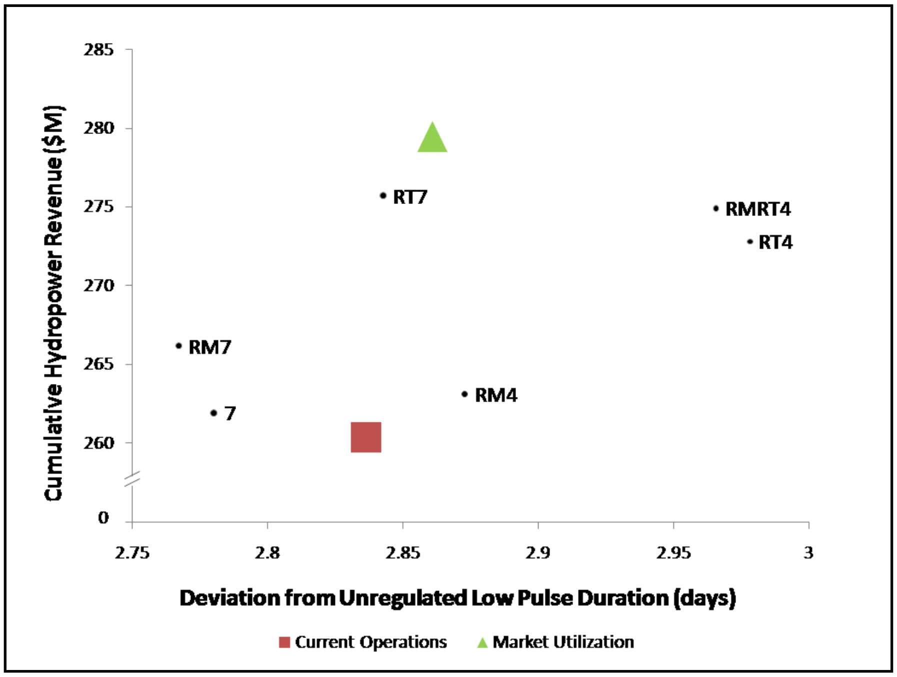

Figure 21. Results from the sensitivity analysis in terms of low pulse duration.

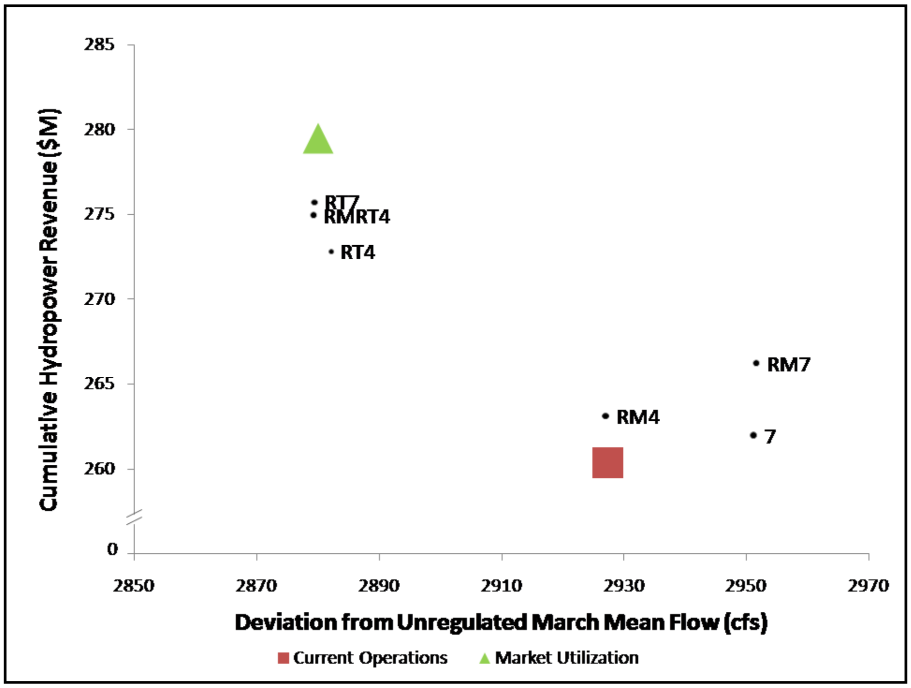

Figure 22. Results from the sensitivity analysis in terms of March mean flow.

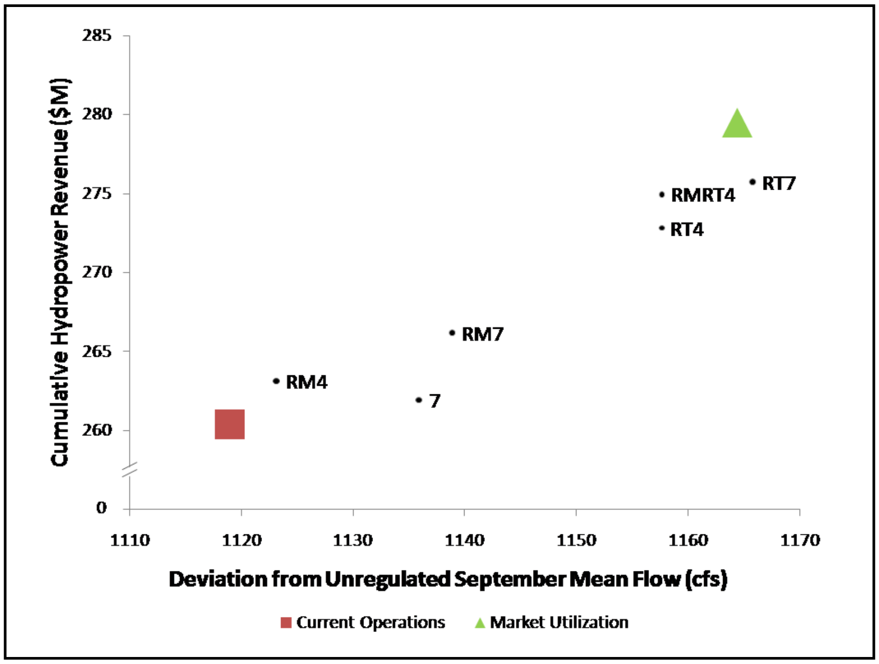

Figure 23. Results from the sensitivity analysis, in terms of September mean flow.

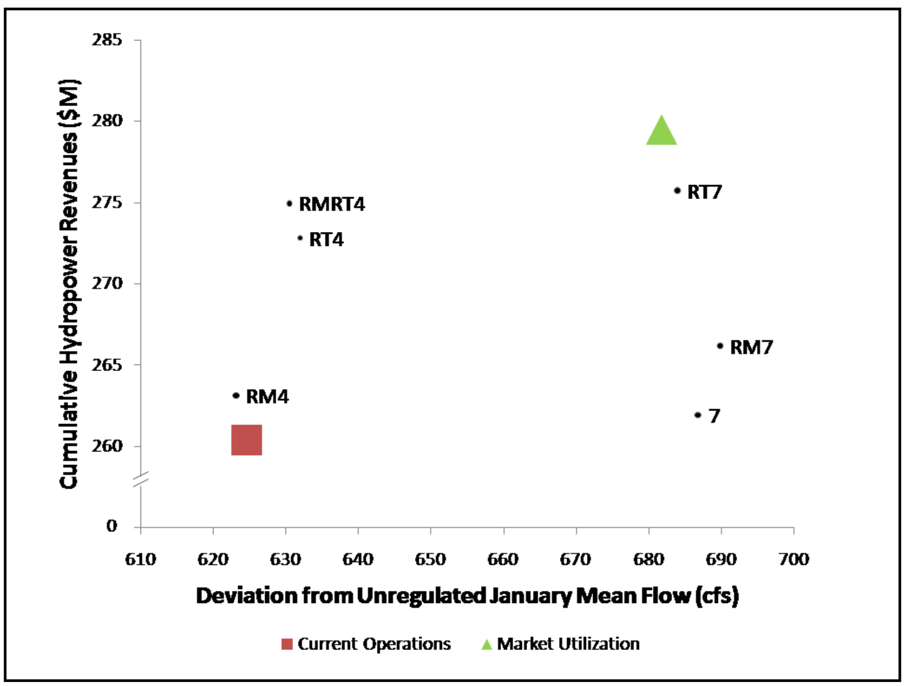

Figure 24. Results from the sensitivity analysis performed on the current operations and market utilization scenarios, shown in terms of January mean flow.