The Flexibility Framework Model: A Tool for Evaluating Hydroelectric Power Plants' Potential for Flexibility Services

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Hydroelectric power plants provide flexibility services for grid reliability and stability. These flexibility services are particularly useful for integrating variable renewable energy resources such as wind and solar. This paper focuses on the Flexibility Framework Model (FFM), which is an innovative, water-based methodology for analyzing and evaluating alternative energy and ancillary services operations.

The FFM includes a calculation engine that co-optimizes energy, regulation, and spinning reserve. The FFM provides an organizing framework (1) to evaluate the effects of these capabilities and constraints on the various types of flexibility operations and services that could potentially be supplied; and (2) to enable more appropriate decision making for investments in plant equipment, for plant operations, for improved understanding of costs and effects from environmental regulations, and for understanding risks associated with climate related changes in hydrology. This paper provides the results from multiple analyses using the FFM methodology.

Introduction

The energy mix across the globe is changing due to efforts to reduce the world's dependence on carbon based generation technologies and as renewable technologies become more cost-effective. Increasing amounts of variable renewable energy (VRE) resources, primarily wind and solar, are coming onto the grid, and hydropower typically provides energy, load regulation, and other ancillary services.

These flexibility services from hydroelectric power plants provide grid reliability and stability. The flexibility services are particularly useful for integrating VRE resources, including wind and solar. The U. S. Department of Energy (DOE) is sponsoring the Hydropower Flexibility Framework (HFF) project to develop a Flexibility Services Directory (FSD), a Plant Capabilities and Constraints Catalog (PCCC), and a Flexibility Framework Model. A hydropower plant's abilities to provide flexibility services (included in the FSD) depend on its fuel (water availability and water-specific constraints), the plant-specific electrical and mechanical capabilities and constraints, and the environmental and regulatory constraints (included in the PCCC).

The Flexibility Framework Model includes a calculation engine that co-optimizes energy, regulation, and spinning reserve. Its components are the minimum/environmental flow characteristics, an associated reservoir curve, and a plant model. The reservoir curve includes the reservoir volume versus elevation, and the plant schedule includes the minimum flow characteristics. The plant model, which enables the optimized plant efficiency calculations, includes optimized plant efficiency matrices, optimized regulation matrices, and a spin deployment probability to account for the water use with spinning reserve commitments.

Background for the Flexibility Framework Model

Unit and Plant Performance Curves

Optimization analyses are based on unit and plant performance curves. An example of a unit performance curve, based on previous case studies, is provided for a single head in Figure 1.

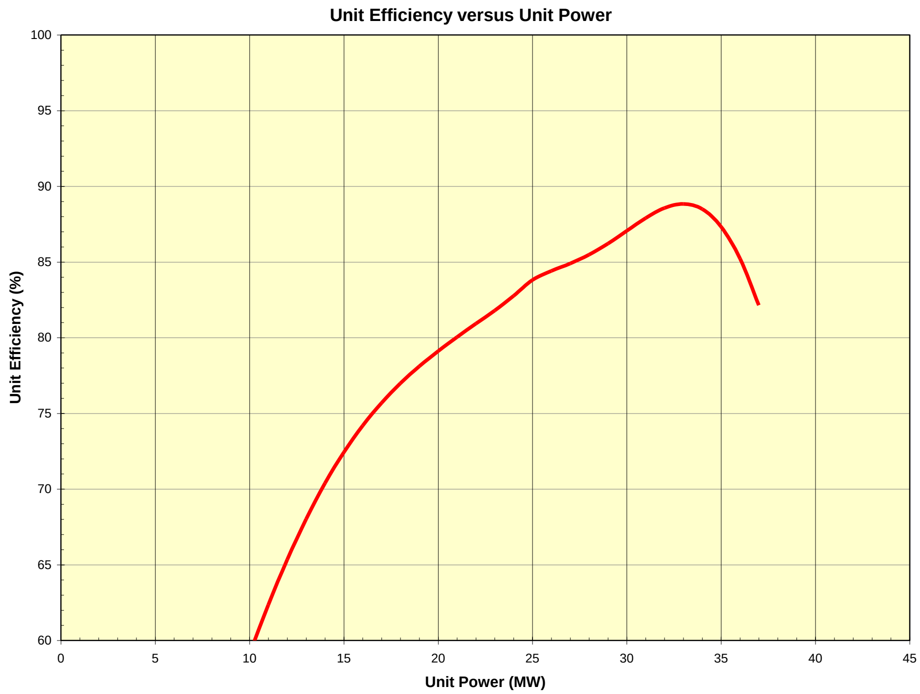

Figure 1: Unit Performance versus Unit Power at a Single Head

Optimized plant performance curves are computed from unit performance curves with the Hydroplant Performance Calculator [March et al., 2014], using the methodology described in EPRI [2020] and ASME [2020]. Figure 2 shows the optimized plant performance versus plant power for a three unit plant with identical units.

Adding Regulation to Unit and Plant Performance Curves

For regulation analyses, the unit performance curve is modified to include a unit power set point and a unit power swing for regulation. The swing is defined as the allowable power variation (+/-) from the set point. For example, a unit with a set point of 31 MW and a swing of 6 MW (see Figure 1) would provide regulation from 25 MW (-6 MW) to 37 MW (+6 MW).

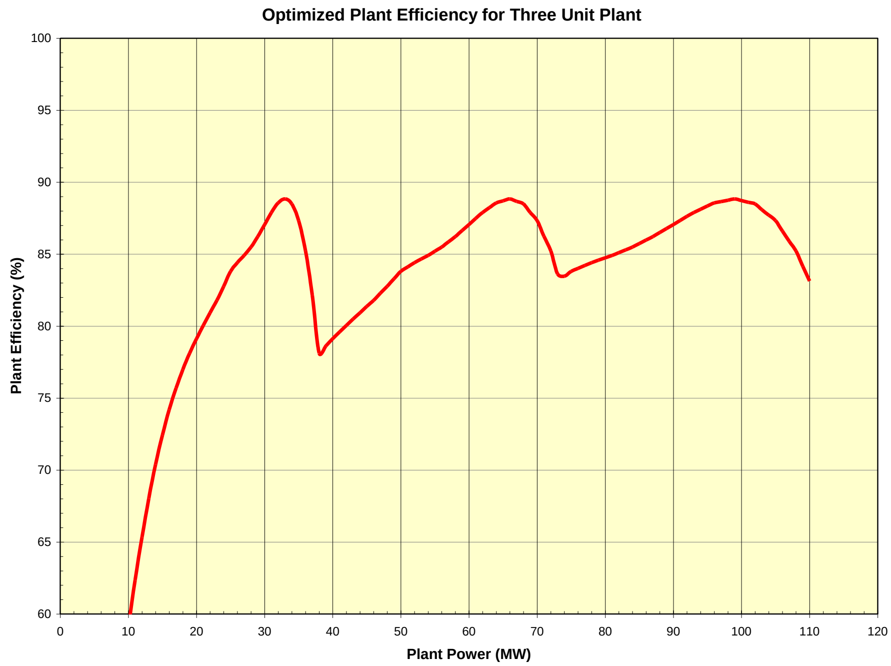

Figure 2: Optimized Plant Performance versus Plant Power for a Three Unit Plant at a Single Head

Similarly to Figure 2, unit performance curves with regulation can be combined to provide optimized plant performance curves with varying amounts of regulation. Typically, hydropower plants provide fixed dispatch regulation, with units operating together and with each unit providing the same amount of swing in response to an automatic generation control (AGC) signal. During operation for regulation, some hydropower plants with advanced control systems continually re-optimize the plant dispatch in response to a load request [Giles et al., 2003; EPRI, 2012; March et al., 2013; EPRI, 2017]. This is called optimized dispatch regulation.

By assuming a probabilistic distribution for the power occurrences across the regulation zone, a unit performance curve with regulation can be computed. Figure 3 shows a normal (Gaussian) distribution for power occurrences across the regulation zone. Figure 4 provides modified unit performance curves computed for varying amounts of swing ranging from 0 MW (no regulation) to +/-14 MW, using an assumed normal distribution of swing loads.

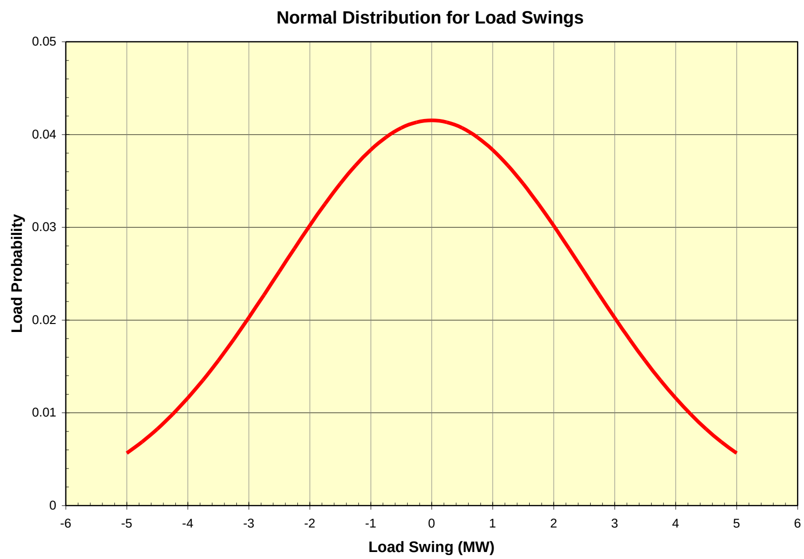

Figure 3: Normal Distribution for Load Occurrences across the Regulation Zone

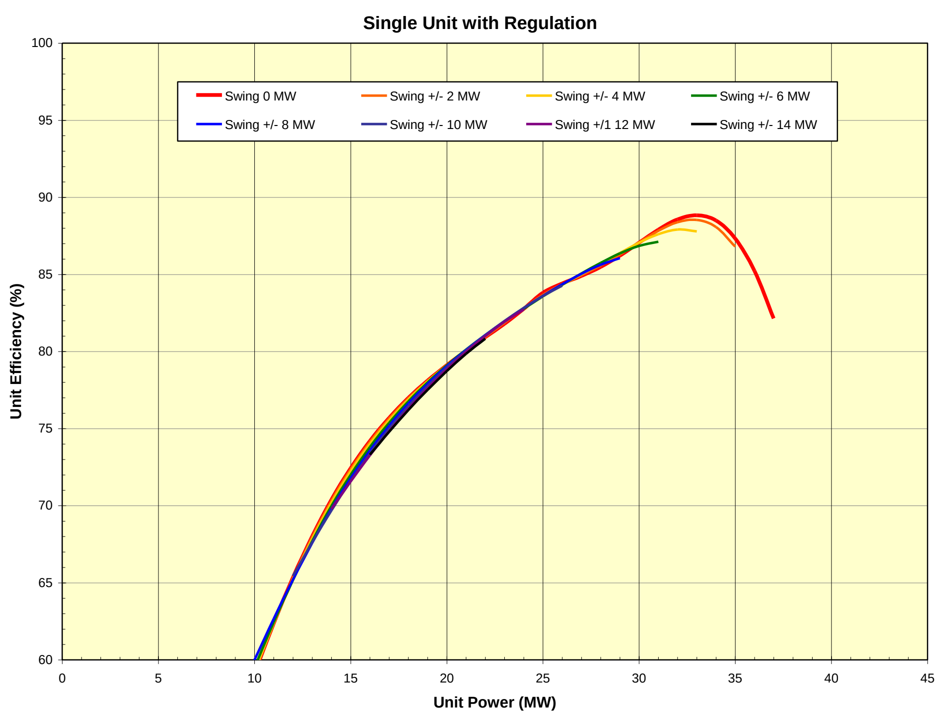

Figure 4: Unit Performance Curves with Increasing Regulation

Figure 5 shows optimized plant performance curves for a three unit plant with regulation using fixed dispatch, and Figures 6 and 7 show optimized plant performance curves for a three unit plant and for an eight unit plant, respectively, with regulation using optimized dispatch. EPRI [2020] provides the detailed methodology for determining the optimized plant performance curves.

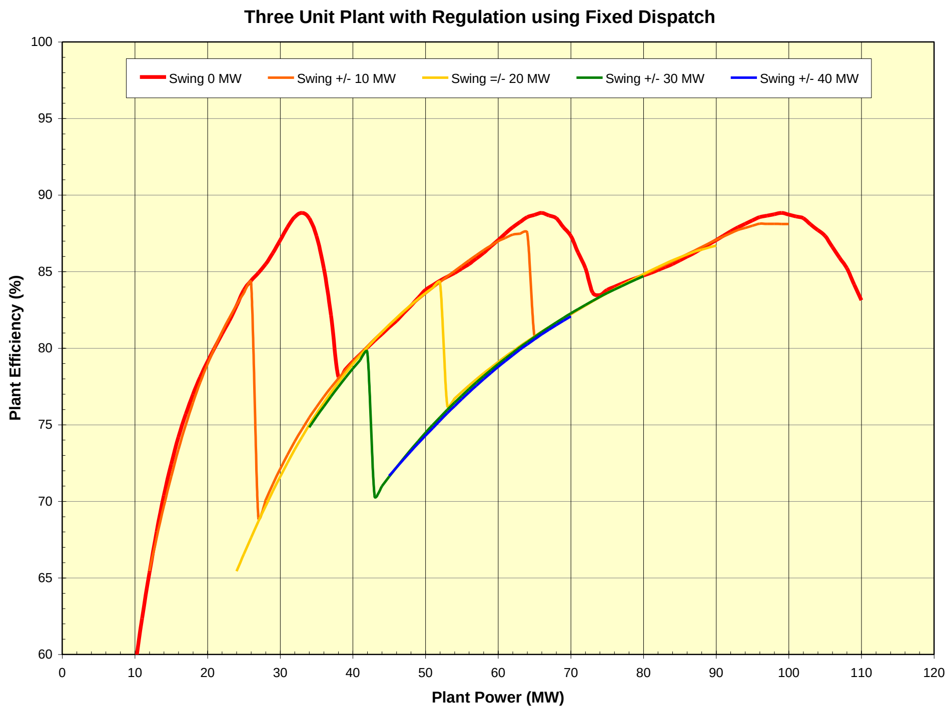

Figure 5: Three Unit Plant Performance Curves with Regulation using Fixed Dispatch

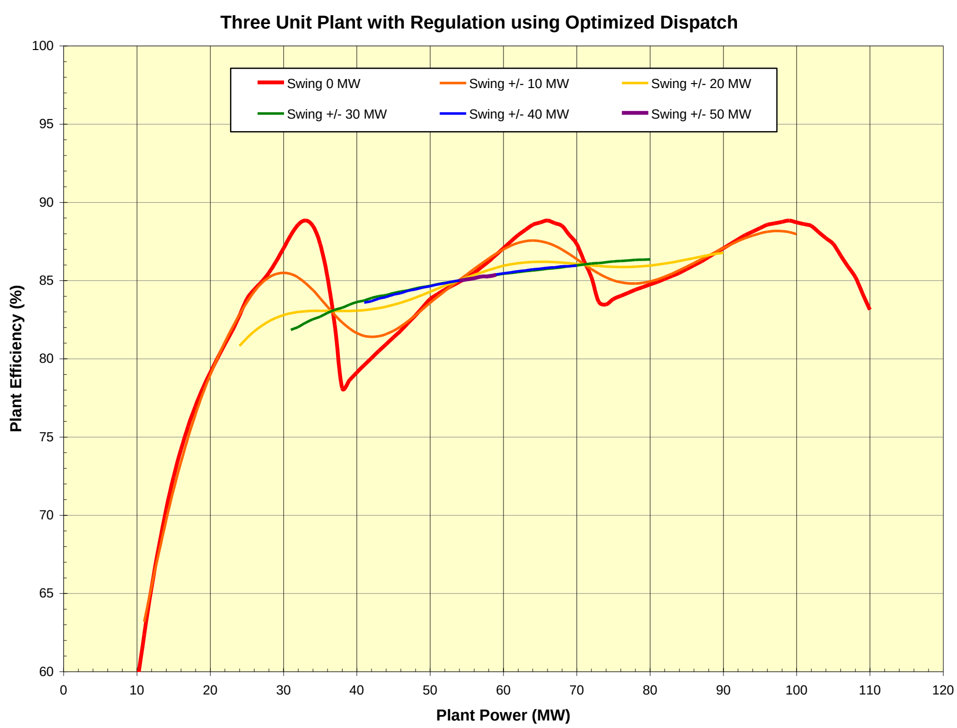

Figure 6: Three Unit Plant Performance Curves with Regulation using Optimized Dispatch

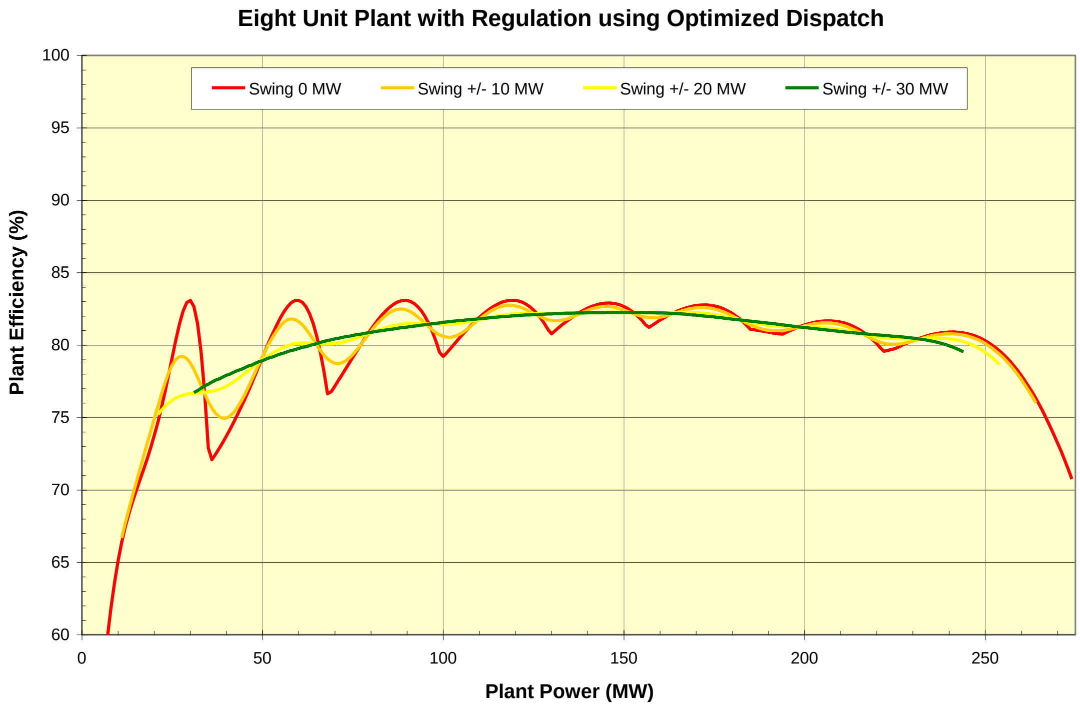

Figure 7: Eight Unit Plant Performance Curves with Regulation using Optimized Dispatch

Results from FFM Analyses

FFM Analyses with Day Ahead Schedules

Analyses using the FFM were computed for an actual eight unit plant operating with the Midcontinent Independent System Operator (MISO). This case study plant has eight Francis units of three different types. Figures 8 and 9 compare the day ahead schedules provided to the plant by MISO with the day ahead schedules computed by the FFM for eight days in February of 2022. The co-optimized schedule provided by the FFM was consistent with the day ahead schedule provided by MISO, and the solution provided by the FFM resulted in a revenue increase of 2.4%. Figure 9 shows that the FFM solution included a small amount of additional regulation compared to the MISO day ahead schedule.

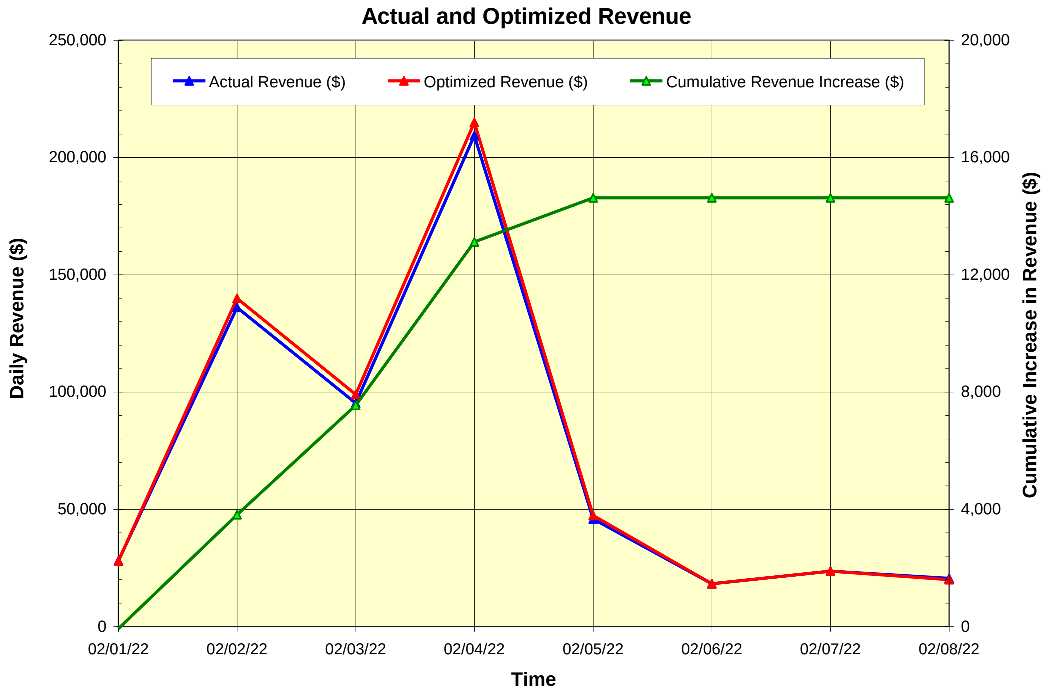

Figure 8: Actual and Optimized Revenue for an Eight Unit Plant Operating in the MISO Market

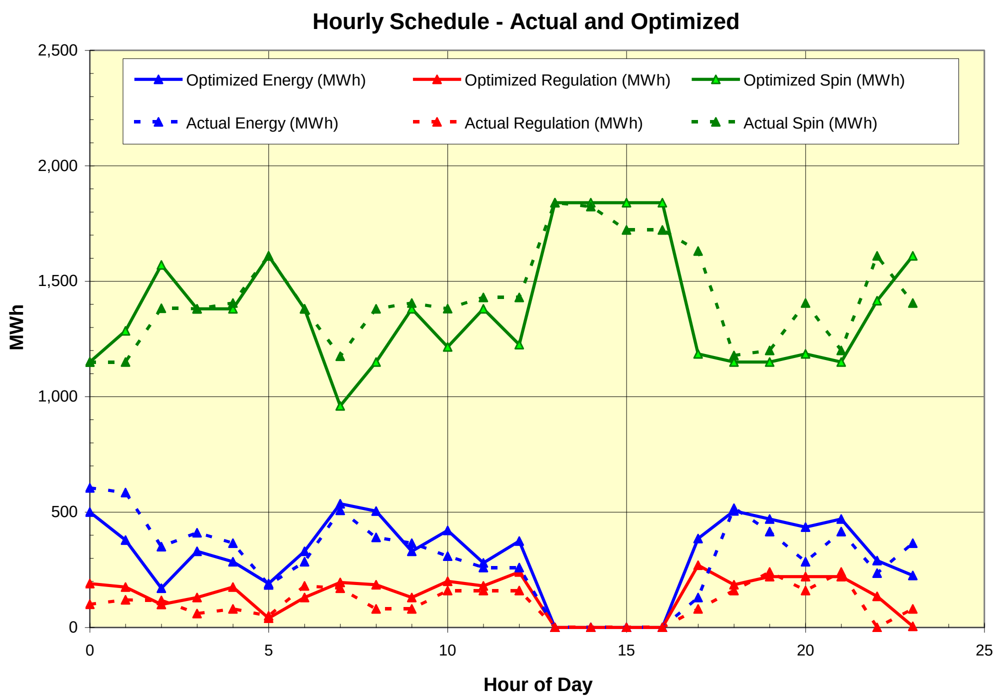

Figure 9: Actual and Optimized Energy, Regulation, and Spinning Reserve Schedules for an Eight Unit Plant Operating in the MISO Market

Multi-Day Forecast Analyses

The FFM can also compute multi-day forecast analyses. For the forecast analyses, a multiple day water budget is used with predicted prices to determine the schedules that co-optimize the generation and flexibility services. Figures 10, 11, and 12 present results from a three day forecast analysis that is based on the same data set used in the comparison between the MISO and FFM schedules, as discussed in the previous section. Comparing a three day forecast analysis to day ahead schedules consists of the following steps:

1. For day 1, combine the water budget for days 1 through 3.
2. Use the day ahead and forecasted prices for days 1 through 3.
3. Compute the three day co-optimized schedule using the FFM.
4. Store the day 1 solution for comparison to the day ahead schedule.
5. For day 2, combine the water budget for days 2 through 4 and adjust it with the difference in water use that occurred between the three day forecast solution and the day ahead solution.
6. Then, proceed with step 2 but using prices for days 2 through 4.
7. Continue until the solution is obtained for the desired time span.

With this approach, a forecast analysis was run for five days from February 1 through 6 of 2022, during a time when limited flow was available to the plant. The forecast analysis was compared to the day ahead co-optimized schedule to quantify the differences between these two approaches. As shown in Figure 10, the schedule computed with the three day forecast increased the plant revenue by 13.4%. However, other forecast analyses under conditions with higher available flows typically showed less improvement. The total energy generation was approximately the same for the five day span of the day ahead and three day forecast schedule but differed from day to day, as shown in Figure 11. For example, the three day forecast used more water on the first and third days when the energy prices were highest.

Figure 12 presents the hourly energy prices and energy generation for the day ahead and three day forecast analyses. The primary advantage of the three day forecast analysis is that water is allocated to days when the energy prices were highest. For example, the water budget for day 1 of the day ahead schedule was limited to minimum flow generation. The three day schedule provided additional water to that day to provide generation when the energy price was highest, exceeding $100/MWh.

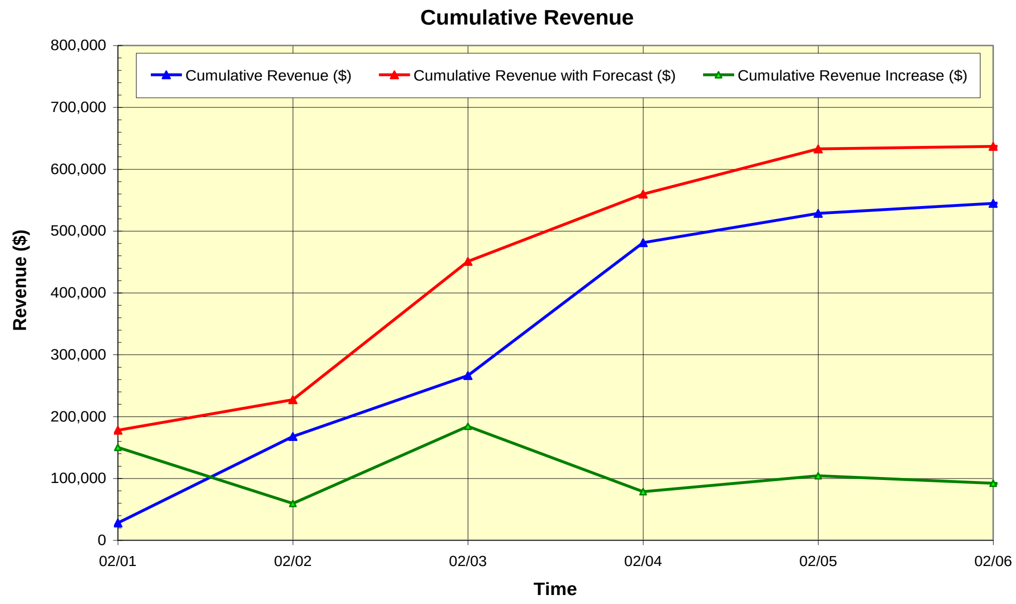

Figure 10: Cumulative Revenue for Optimized Day Ahead Schedule and for Three Day Forecast Schedule

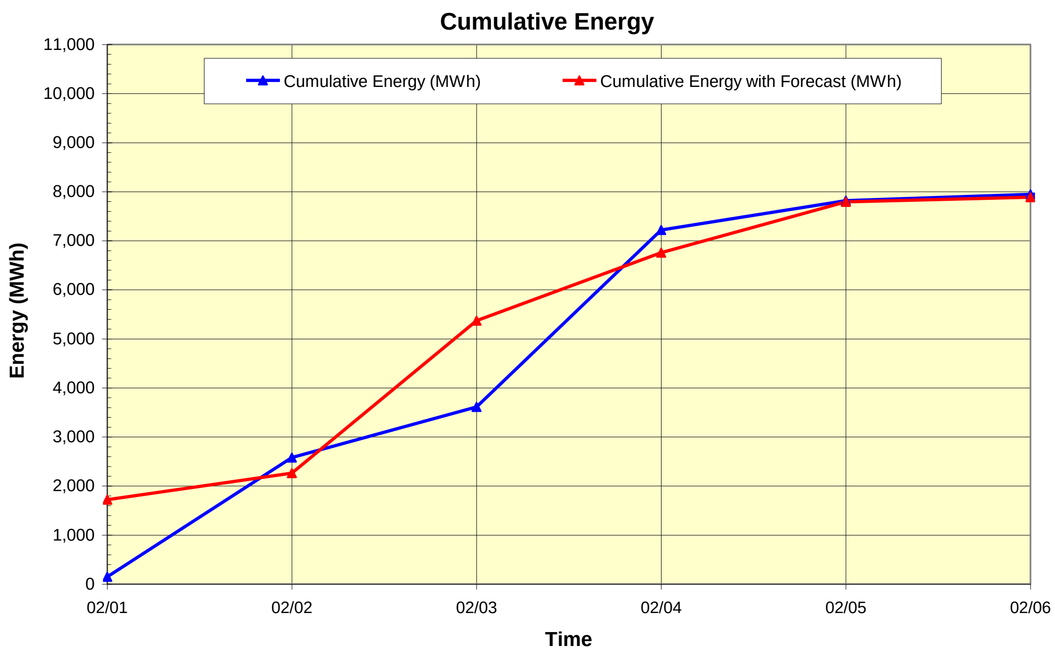

Figure 11: Cumulative Energy Production for Optimized Day Ahead Schedule and for Three Day Forecast Schedule

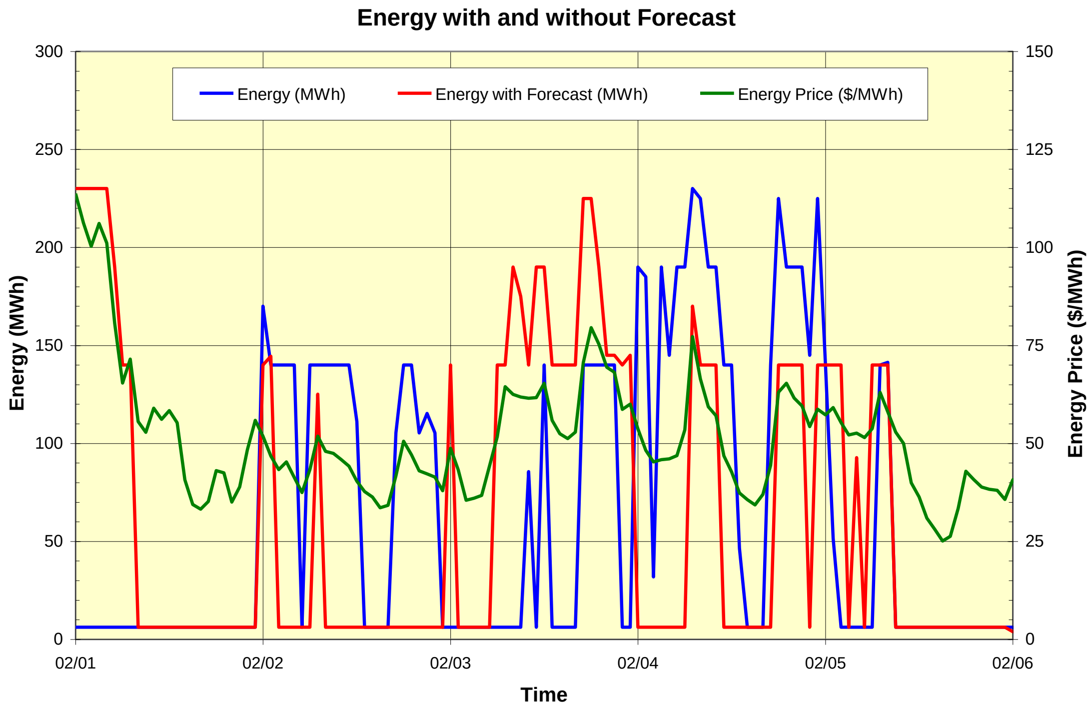

Figure 12: Hourly Energy Production for Day Ahead Schedule and for Three Day Forecast Schedule

Analyses of Generation and Flexibility Services over a Plant's Flow Range

Additional analyses with the FFM and the eight unit plant computed the maximum amount of energy, regulation, and spinning reserve provided by a co-optimized schedule for different prices over the full range of water flow that can be used for power generation. Two MISO day ahead price schedules were used for these analyses including the prices for 2/20/2020 (Figure 13) and for 7/20/2020 (Figure 14). In addition, constant prices were used that included an energy price of $25/MWh, a regulation price of $10/MWh, and a spinning reserve price of one dollar per MWh.

The total daily optimized energy, regulation, and spinning reserve provided for each of these prices are shown in Figures 15 through 17. The amount of optimized energy generation is approximately equal for each price profile (Figure 15). The July price profile resulted in less regulation and slightly more spinning reserve than the other prices when the plant flow exceeded 40%.

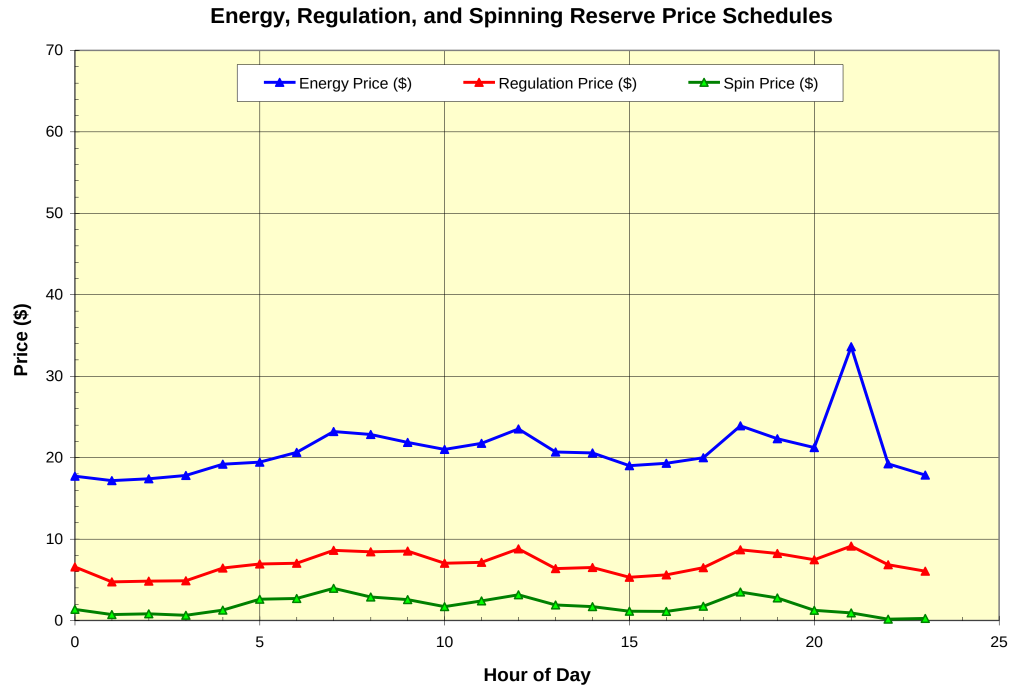

Figure 13: MISO Day Ahead Prices for February 20, 2020

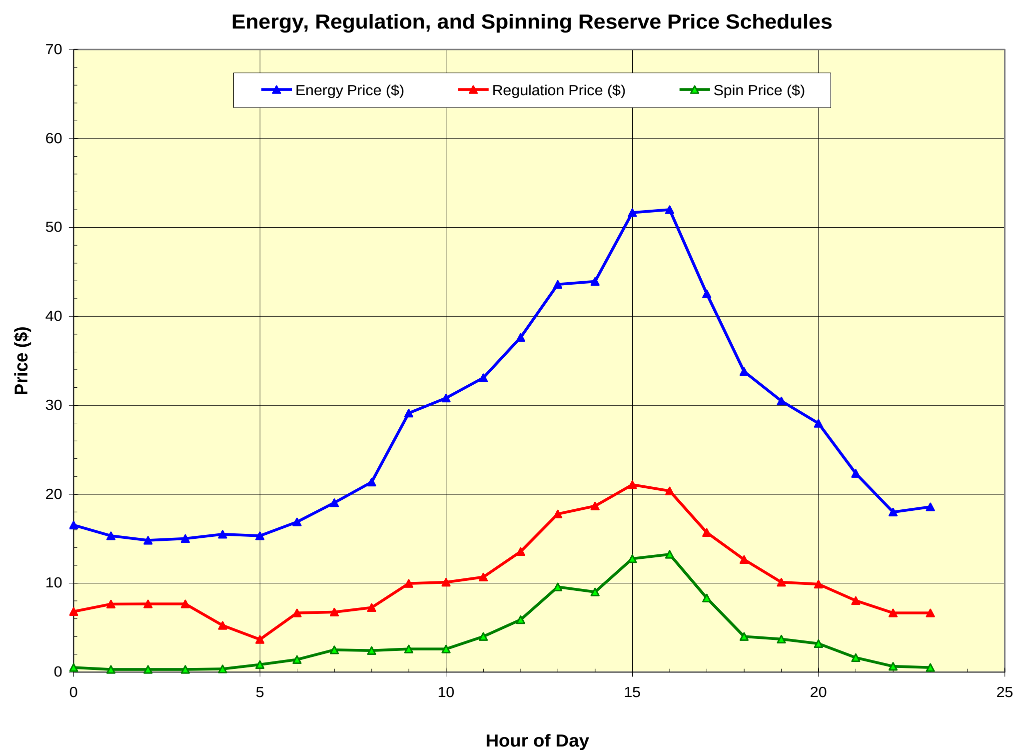

Figure 14: MISO Day Ahead Prices for July 20, 2020

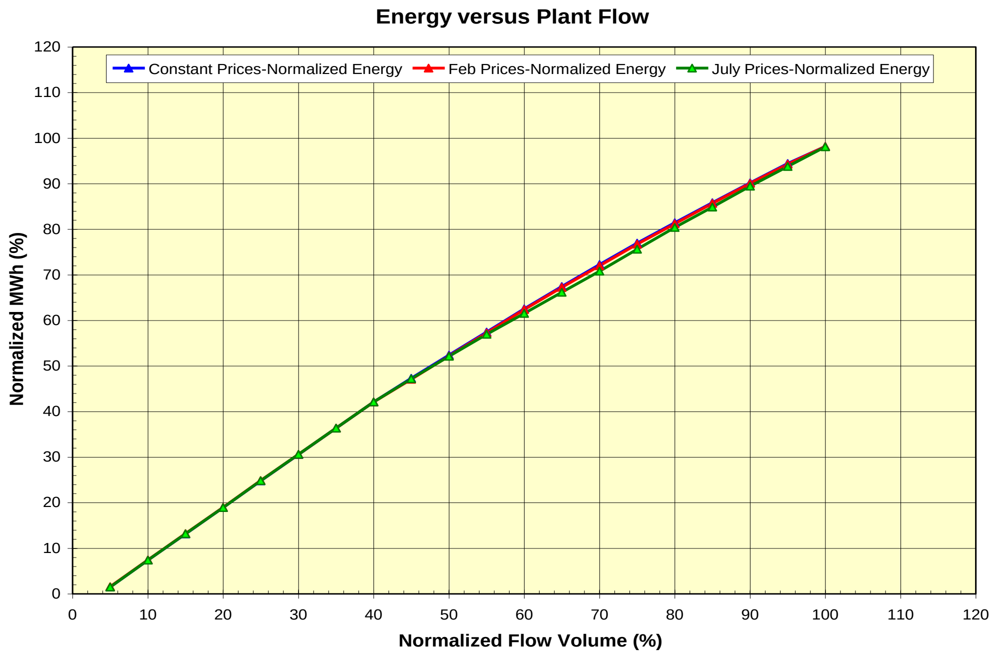

Figure 15: Optimized Energy Production versus Plant Flow for an Eight Unit Plant with Three Different Price Schedules

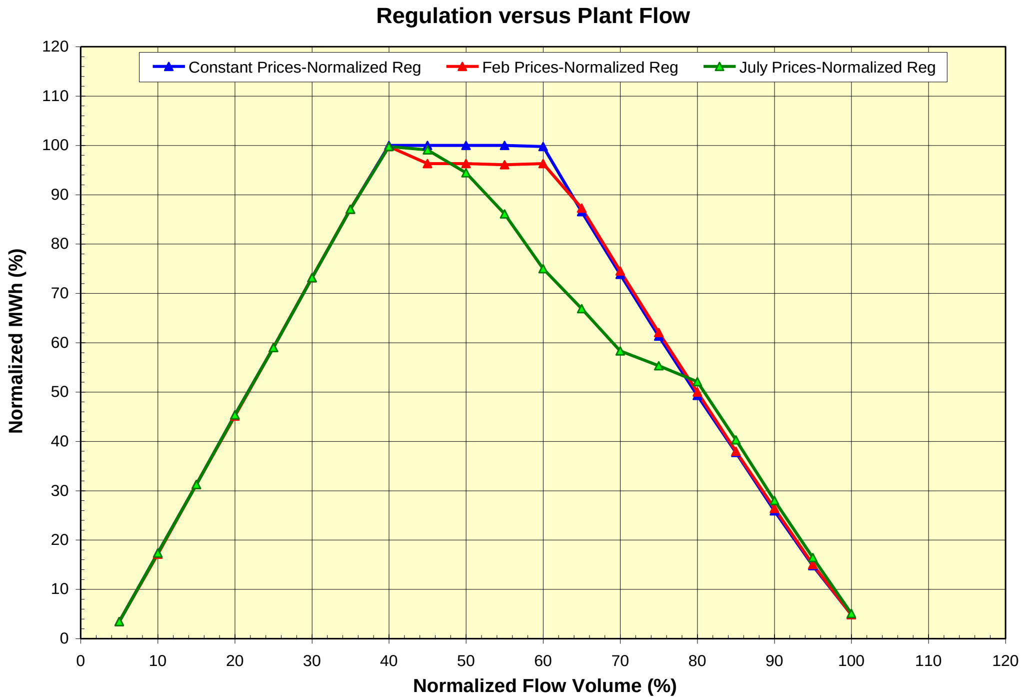

Figure 16: Optimized Regulation versus Plant Flow for an Eight Unit Plant with Three Different Price Schedules

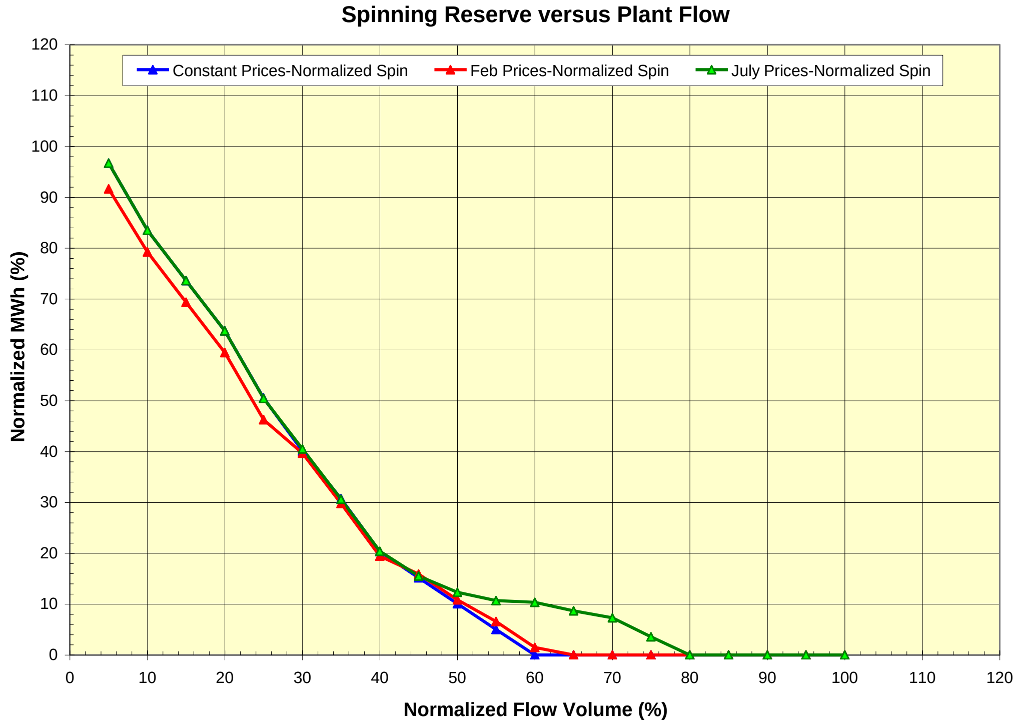

Figure 17: Optimized Spinning Reserve versus Plant Flow for an Eight Unit Plant with Three Different Price Schedules

The optimized hourly solution when the plant flow volume was 65% is provided in Figure 18. This figure shows that the hourly co-optimized solution provided no regulation when the energy prices were the highest. Figures 19 through 21 compare the three and eight unit plants' co-optimized schedules with constant price profiles. The curves are approximately the same, indicating that the normalized curves may be similar for plants of different configurations.

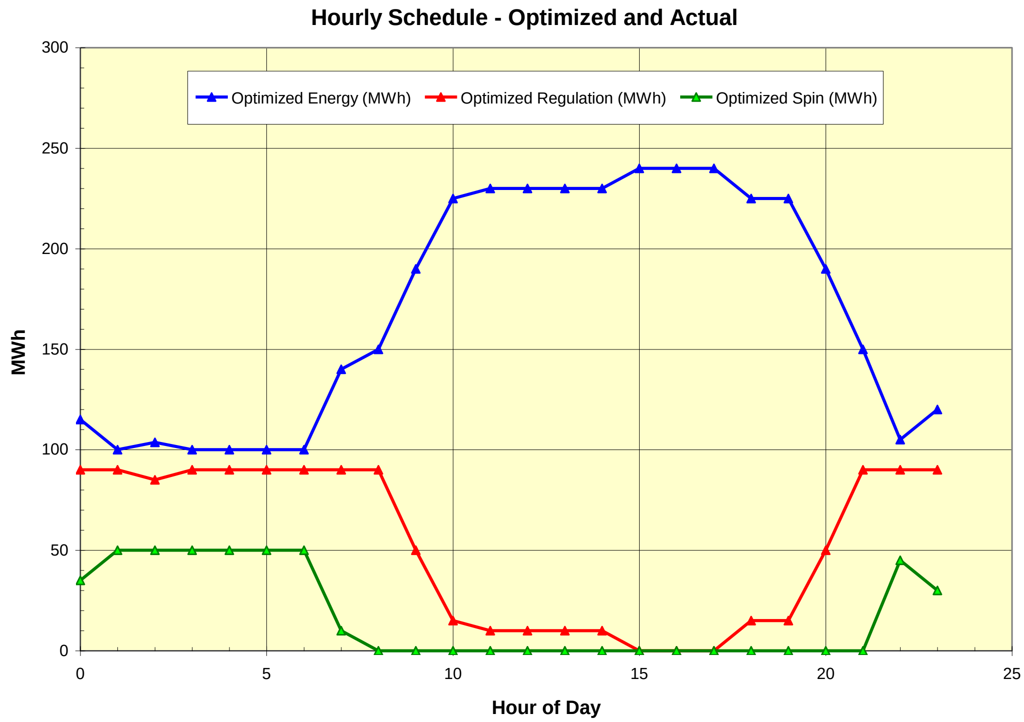

Figure 18: Hourly Energy, Regulation, and Spinning Reserve for a Plant Flow Volume of 65% and for July Price Schedule

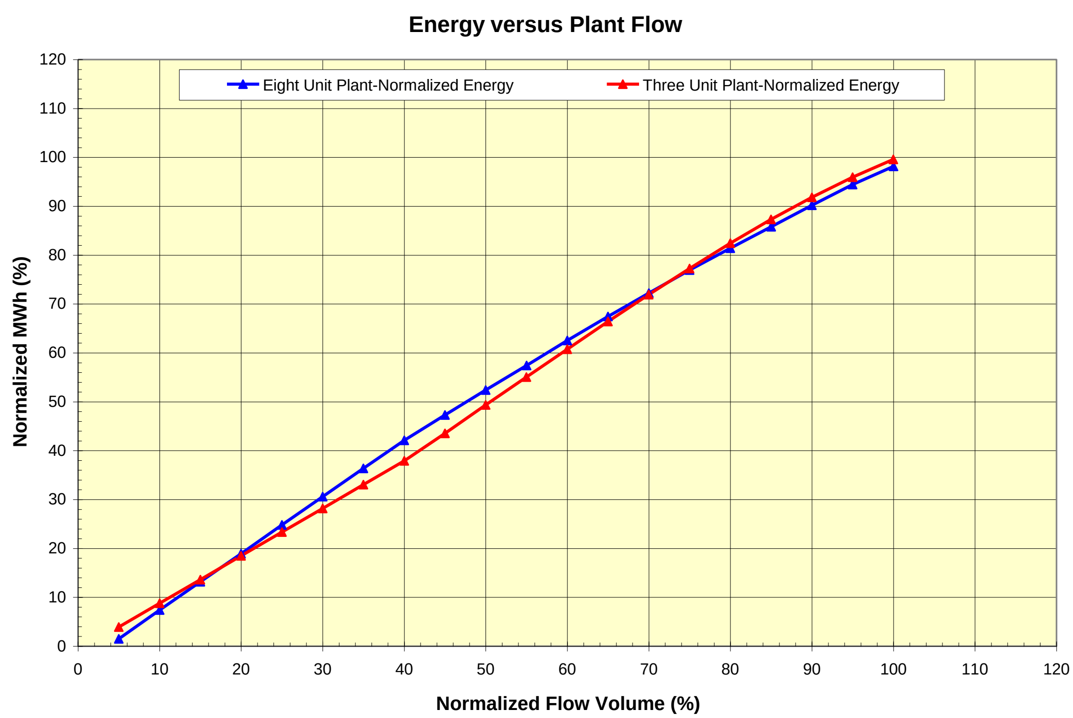

Figure 19: Optimized Energy Production versus Plant Flow for an Eight Unit Plant and a Three Unit Plant with Constant Prices

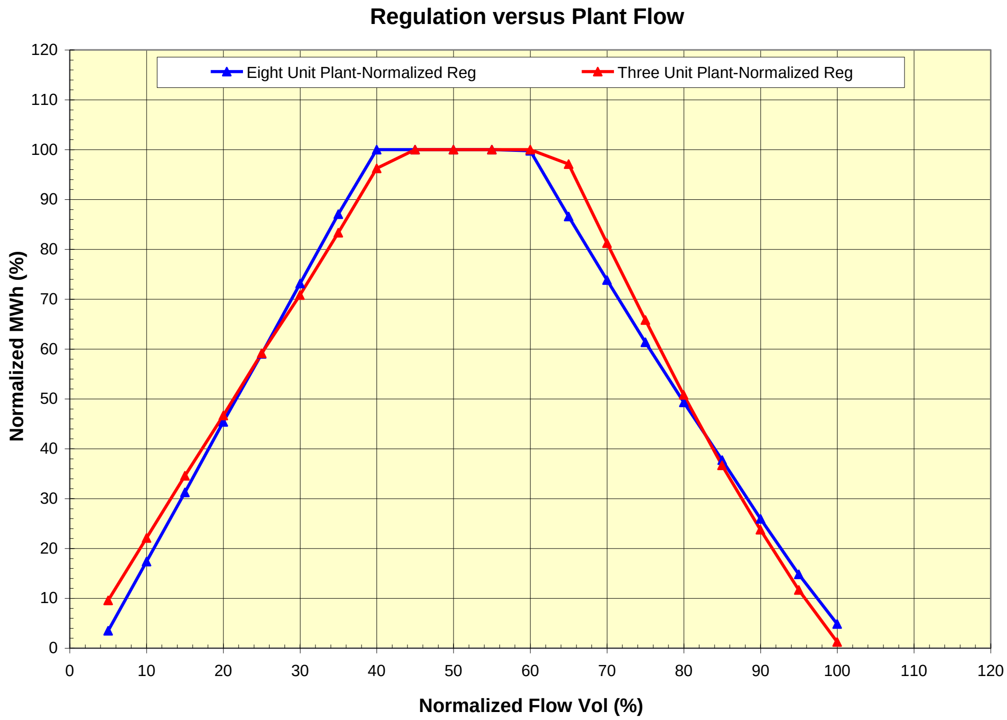

Figure 20: Optimized Regulation versus Plant Flow for an Eight Unit Plant and a Three Unit Plant with Constant Prices

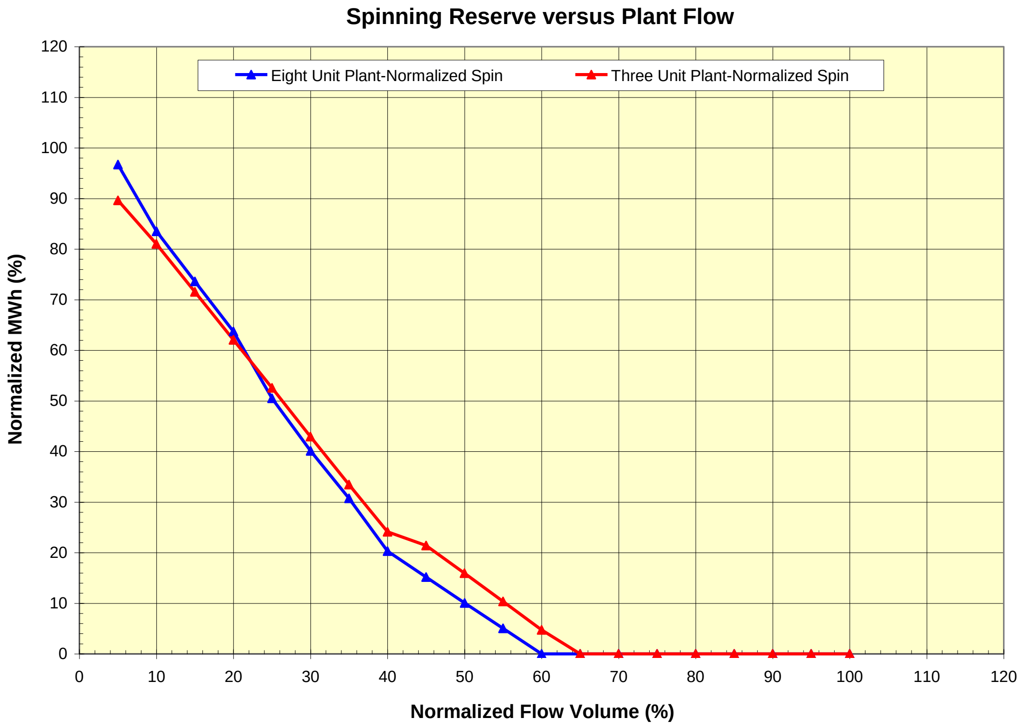

Figure 21: Optimized Spinning Reserve versus Plant Flow for an Eight Unit Plant and a Three Unit Plant with Constant Prices

Conclusions and Recommendations for Future Work

Conclusions

This paper focuses on the Flexibility Framework Model (FFM), an innovative, water-based methodology for analyzing and evaluating alternative energy and ancillary services operations. The paper describes the methodology and provides results from multiple analyses using this methodology, including analyses with day ahead price schedules, multi-day forecast analyses, and analyses of generation and flexibility services over a plant's flow range. The analyses with day ahead price schedules showed some relatively small improvements compared to the market-based dispatch. However, multi-day forecast analyses showed the potential for significant revenue increases, with an example provided of a 13.4% improvement in revenue. The analyses of generation and flexibility services over a plant's flow range illustrate how the amount of energy and the amount of flexibility a plant can provide depend on both the plant flow available and on the price profile. Also, these analyses showed similar patterns with a three unit plant and with an eight unit plant, potentially indicating a path forward for using the FFM and appropriate assumptions to estimate the flexibility potential for the entire hydropower fleet.

Recommendations for Future Work

Based on these results, recommendations for additional work include:

1. Additional flexibility products, including regulation up and regulation down, should be added to the model.
2. Additional use cases for the FFM should be explored, including providing hydropower asset owners with computations of ancillary services value for upgrade decisions.
3. Co-optimization analyses should be conducted with specific case studies to evaluate the costs for environmental operations which affect the water budget, such as environmental flows.
4. Additional research should be conducted to assess and quantify hydropower plants' increased maintenance and life-cycle costs from ancillary services operation to ensure that market values for ancillary services provide adequate compensation to hydropower plant owners/operators [EPRI, 2012; EPRI, 2017; March et al., 2013; March et al., 2018].

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