Effects of Markets and Operations on the Suboptimization of Pumped Storage and Conventional Hydroelectric Plants

by

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Abstract

The Hydropower Grid Services Project, sponsored by the U. S. Department of Energy and co-sponsored by the hydropower industry, focused on quantifying and maximizing the benefits to transmission grids provided by conventional and pumped storage hydroelectric plants. As part of that project, detailed plant performance analyses for five pumped storage plants and three conventional hydroelectric plants were conducted using unit and plant performance characteristics and plant operational data from 2008, 2009, and 2010. The eight case studies encompass three market regions (MISO, PJM, and NYISO) and two non-market regions (Southeast area and Western area). Owners for the eight plants include three investor-owned utilities, two state power authorities, and one federal power corporation.

This paper describes results from detailed performance analyses which evaluated reductions in overall plant efficiencies under a variety of market-related and operations-related conditions for the plants. Results from this paper show that the non-market operation of both the pumped storage and conventional plants exhibited less suboptimization (i.e., more efficient performance) than the pumped storage and conventional plants operating in established markets. Opportunities are identified for cost-effective plant improvements to reduce avoidable suboptimization and avoidable losses in both pumped storage and conventional hydroelectric plants.

1. Introduction

The U. S. Department of Energy's (DOE's) Hydropower Grid Services Project was initiated to quantify and maximize the benefits provided by conventional and pumped-storage hydroelectric projects to transmission grids, particularly for the integration of variable renewables. Details of the Hydropower Grid Services Project, including a project overview, a description of the modeling approach, a report on plant cost elements, and recent publications, are provided through the Electric Power Research Institute's (EPRI's) web site [EPRI, 2012].

A previous study examining the effects of the MISO ancillary services market on suboptimization of a conventional hydroelectric facility reported a performance reduction by an average of 3.0%, due primarily to the practical necessity of maintaining additional units on line at lower loads to meet anticipated system demand and to avoid excessive unit cycling [March et al., 2010].

This paper utilizes results from additional analyses of the performance assessments conducted for the Hydropower Grid Services Project to extend the previous work and examine suboptimization of five pumped storage plants [March, 2012a; March et al., 2012a] and three conventional hydroelectric plants [March, 2012b] under market and non-market conditions [March, 2012c]. The paper describes the performance assessment process, provides results from performance assessments for the five plants, and discusses the results in a market/non-market context.

2. Overview of Performance Analyses

The performance assessments utilized for this paper are based on a set of analyses to quantify unit and plant performance and to enable the investigation of potential opportunities for operations-based and equipment-based performance improvements, leading to additional generation. This section briefly addresses the processes and methodologies used for the quantitative performance analyses, and additional details are available elsewhere [March, 2008; DOE, 2011; March et al., 2012b].

An overview of the optimization-based performance analyses is shown in Figure 2-1.

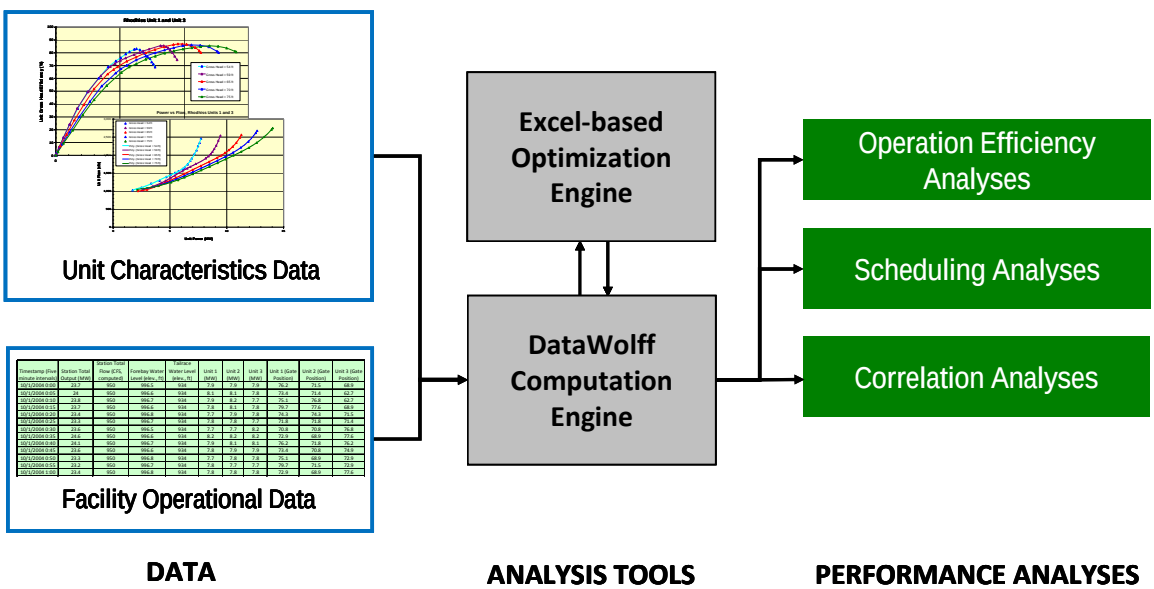

Figure 2-1: Overview of Performance Analyses

Unit characteristics and facility operational data are discussed in Section 3, "Data for Performance Analyses." The performance analysis tools are discussed in Section 4, "Tools for Performance Analyses," and an overview of optimization-based performance analyses is provided in Section 5. Section 6 compares results from market and non-

market plants, and Section 7 provides operations-related results from the performance analyses. Section 8 summarizes and discusses the results.

3. Data for Performance Analyses

The primary data needs for performance analyses include unit characteristics data and facility operational data, which are discussed in the following subsections.

Unit Characteristics Data – Hydroelectric generating facilities convert the potential energy of stored water and the kinetic energy of flowing water into a useful form, electricity. This fundamental process for a hydroelectric generating unit is described by the generating efficiency equation, defined as the ratio of the power delivered by the unit to the power of the water passing through the unit. The general expression for this efficiency (η) is

$$\eta = \frac{P}{\rho g Q H}$$

where P is the output power, ρ is the density of water, g is the acceleration of gravity, Q is the water flow rate through the turbine, and H is the head across the unit.

Efficiency curves provide guidance for the effective use of a hydropower unit or facility. The points of most efficient operation can be identified, and the efficiency penalty for operating away from the optimum can be quantified and evaluated relative to the potential economic benefits from generating at another power level.

Facility Operational Data – Typically, facility operational data is obtained from multiple sources, including plant personnel, central engineering staff, and load control personnel. Essential operational data for operation efficiency analyses, generation scheduling analyses, and correlation analyses include:

- Timestamp;
- Unit Power;
- Unit Flow;
- Headwater Level;
- Tailwater Level;
- Unit Status (e.g., available, unavailable, condensing).

4. Tools for Performance Analyses

As shown previously in Figure 2-1, the primary tools for performance analyses include an optimization engine and a computation engine, which are described in the following subsections.

Optimization Engine – The optimization engine for the optimization-based performance analyses is implemented using the Solver tool in Microsoft Excel. A brief summary of the implementation is included below, and a detailed explanation is provided elsewhere [DOE, 2011; March et al., 2012b].

The optimization engine is used to determine how a given plant power level is allocated among the units to provide the highest possible plant efficiency. The information required includes the plant power, headwater, tailwater, and the unit characteristics. The optimization engine can also incorporate constraints, such as a preferred unit dispatch order. Given this information, the optimization engine computes the unit power allocation that meets the given plant power with the lowest possible water usage, providing the highest possible plant efficiency.

Computation Engine – The primary computation engine is DataWolff, an Excel-based program that enables the automating of multiple data analyses. Additional configuration of the computation engine with specific analysis scripts and calculation libraries is required for each particular type of analysis. The optimization-based performance analyses use procedures provided in detail elsewhere [March, 2008; DOE, 2011; March et al., 2012b].

5. Optimization-Based Performance Analyses

Optimization technologies and recent advances in automated data analyses provide the tools for conducting detailed, optimization-based performance analyses [Giles et al., 2003; March and Wolff, 2003; March and Wolff, 2004; March et al., 2005; Wolff et al., 2005; Jones and Wolff, 2007; March, 2008]. Typical optimization-based performance analyses include operation efficiency analyses, generation scheduling analyses, and correlation analyses. Results from these analyses can be presented in easily understood units, including lost energy opportunity (LEO, in MWh) and lost revenue opportunity (LRO, in $). A diagram of the overall process for optimization-based performance analyses is shown in Figure 5-1, and the specific analyses are described in this section and the following sections.

Overview of Facilities – Detailed performance assessments have been completed for five pumped storage facilities [March, 2012a; March et al., 2012a] and three conventional hydroelectric plants [March, 2012b], using unit and plant performance characteristics and plant operational data from 2008, 2009, and 2010. The five pumped storage plants and three conventional hydroelectric plants included in these analyses encompass three market regions (MISO, PJM, and NYISO) and two non-market regions (Southeast area and Western area). Owners for the eight plants include three investor-owned utilities, two state power authorities, and one federal power corporation. Due to the confidential nature of the performance data, some results from the assessments are not available for public distribution.

Single Unit Performance and Plant Performance - The single unit performance characteristics for the eight plants were typically supplied by the facility owners. This performance data came from a variety of sources, including physical modeling, numerical modeling, and field testing of existing and upgraded turbines or pump-turbines. Based on the unit performance curves, the optimization engine (see Section 4) was used to compute optimized plant gross head efficiencies for each facility. Figure 5-2 shows typical optimized plant gross head efficiencies versus plant power at multiple gross heads for one of the pumped storage plants, and Figure 5-3 shows typical optimized plant gross head

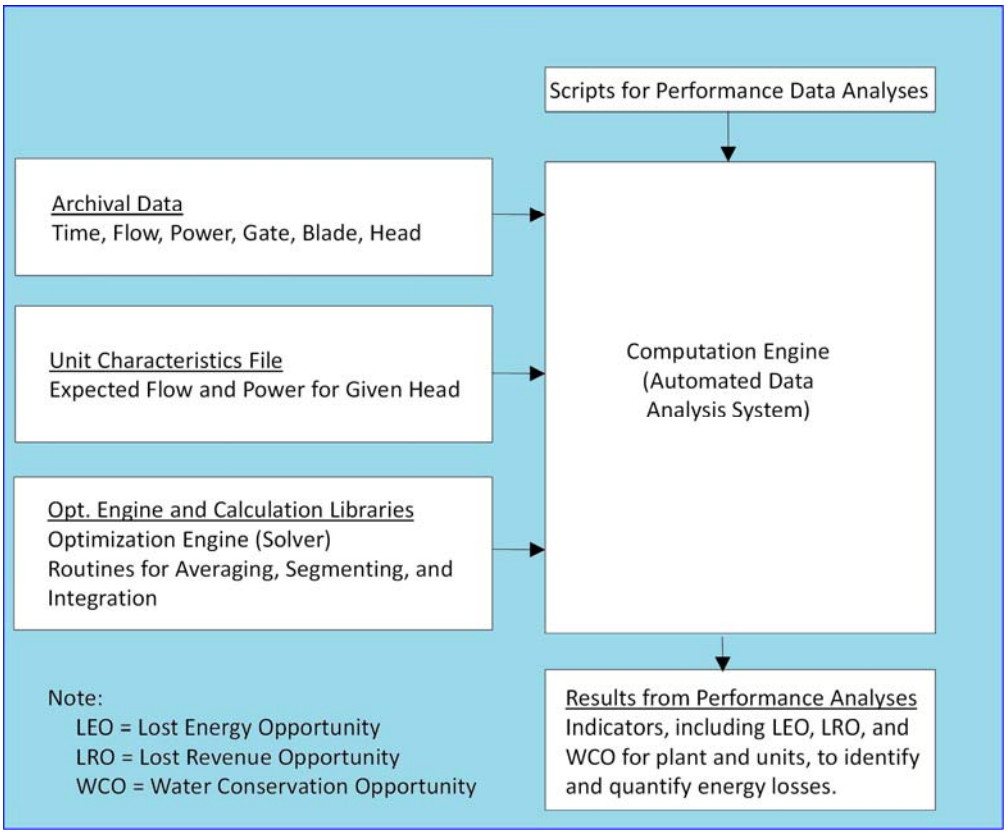

Figure 5-1: Process Diagram for Optimization-Based Performance Analyses

efficiencies versus plant power at multiple gross heads for one of the conventional hydroelectric plants. For each head, the first peak in Figure 5-2 or 5-3 corresponds to the operation of the most efficient unit (or any unit, if the units are identical), the second peak corresponds to the most efficient operation of the two most efficient units, the third peak corresponds to the most efficient operation of the three most efficient units, etc. As more units operate, the peak efficiencies fall, and the peaks become broader.

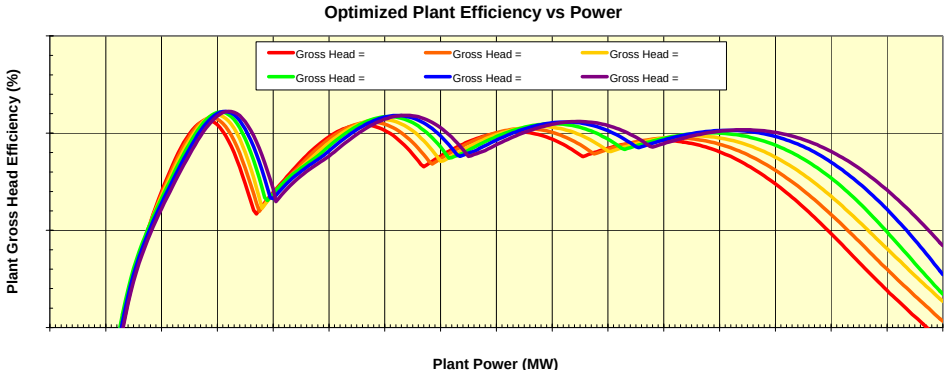

Figure 5-2: Typical Optimized Plant Gross Head Efficiency versus Plant Power for a Pumped Storage Plant

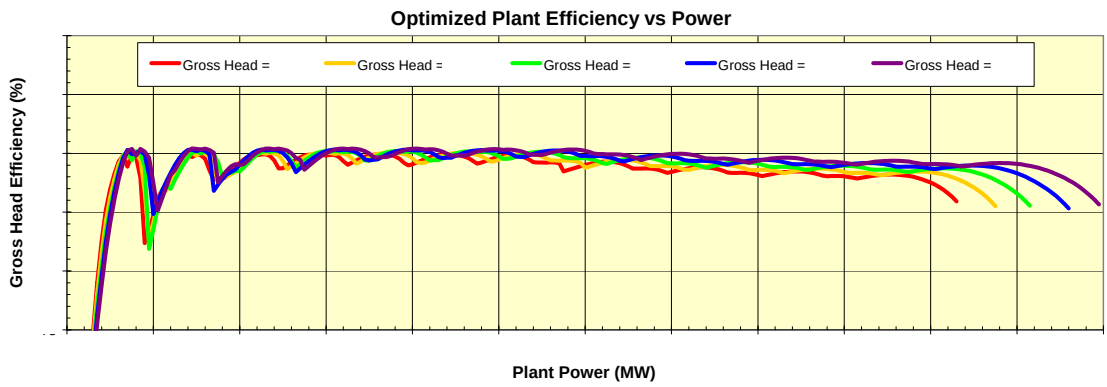

Figure 5-3: Typical Optimized Plant Gross Head Efficiency versus Plant Power for a Conventional Plant

Operation Efficiency Analyses – Operation efficiency analyses use the unit efficiency characteristics and archival operations data to determine how closely the actual dispatch matches the optimized dispatch while meeting the actual power versus time. The computational steps for determining the operation efficiency are discussed elsewhere [March, 2008; DOE, 2011]. At each time step of the archival data, the optimized plant efficiency is computed, apportioning the total plant load among the available units to maximize the plant efficiency while meeting the necessary constraints (e.g., matching the actual plant load, matching the head, and operating each unit within minimum and maximum power limits). Energy gains due to water savings from optimized dispatch are computed by assuming that the water is converted into energy at the optimized plant efficiency and head for the time step in which the potential energy gain occurs.

Results from the operation efficiency analyses are summarized for the five pumped storage plants in Table 5-1 and for the three conventional hydroelectric plants in Table 5-2.

Table 5-1: Summary of Results from Operation Efficiency Analyses for Five Pumped Storage Plants

Plant	Potential Improvement Based on Op. Eff. Analyses (%)
1	0.46
2	0.01
3	0.93
4	1.07
5	0.40

Table 5-2: Summary of Results from Operation Efficiency Analyses for Three Conventional Hydroelectric Plants

Plant	Potential Improvement Based on Op. Eff. Analyses (%)
6	2.70
7	0.94
8	0.50

For the pumped storage plants, the average for the potential plant generation improvements from direct optimization, while producing the same power at the same time, ranged from a low of 0.01% for Plant 2, which participates in an energy market and provides limited ancillary services (spinning reserve and offline supplemental reserve, but not regulation), to a high of 1.07% for Plant 4, which participates in both energy and ancillary services markets. For the conventional hydroelectric plants, the average for the potential plant generation improvements from direct optimization, while producing the same power at the same time, ranged from a low of 0.50% for Plant 8, which provides energy, ancillary services, and flow within a non-market region, to a high of 2.70% for Plant 6, which participates in both energy and ancillary services markets.

The potential generation improvements summarized in Table 5-1 and Table 5-2 are based on an unconstrained optimization. For each plant, the actual operation is based on power system needs or market requirements for energy and ancillary services and river system flow requirements, which can dictate the number of operating units, and on maintenance considerations, which can limit the available units and the number of allowable starts and stops. Consequently, some of the generation improvements identified by the operation efficiency analyses may not be practically achievable. However, for all eight plants, much of the potential generation increase from direct optimization may be cost-effectively achievable through automation, improved optimization, and control system improvements.

Generation Scheduling Analyses - The generation scheduling analyses evaluate how closely the actual plant power levels align with the overall peak efficiency curves for the entire plant. The steps for computing the generation scheduling analyses are provided elsewhere [March, 2008; DOE, 2011]. Individual unit characteristics combine to create an overall plant efficiency that is the maximum plant efficiency achievable for any given load with optimized plant dispatch. By scheduling plant loads to align with peak operating efficiency regions when hydrologic conditions, power system needs, market conditions, and other restrictions permit, more efficient energy generation is achieved.

Figures 5-4 and 5-5 provide typical results from generation scheduling analyses for two pumped storage plants, and Figures 5-6 and 5-7 provide typical results from generation scheduling analyses for two conventional plants. In each figure, the optimized plant gross head efficiency for the particular head is shown in red, the actual monthly generation versus plant power is shown in blue, and the optimized monthly generation

versus plant power is shown in green. The optimized generation occurs at or near the peak efficiencies corresponding to the number of operating units.

The pumped storage plant in Figure 5-4 is dispatched for energy and ancillary services within a vertically integrated power system, rather than in a defined market. This plant tends to operate within a range of powers near the best efficiency values. Virtually identical results were found for the other pumped storage plant dispatched for energy and ancillary services within a vertically integrated power system. The pumped storage plant in Figure 5-5 operates in a well-established market where it is dispatched by individual units primarily for ancillary services rather than energy during the time period shown in the figure. This plant operates over a wide range of power levels.

The conventional plant in Figure 5-6 is dispatched for energy and ancillary services within a non-market region. This plant tends to operate over a broad range of power values and flow values. The conventional plant in Figure 5-7 operates in a well-established market where it is dispatched primarily for energy and flow.

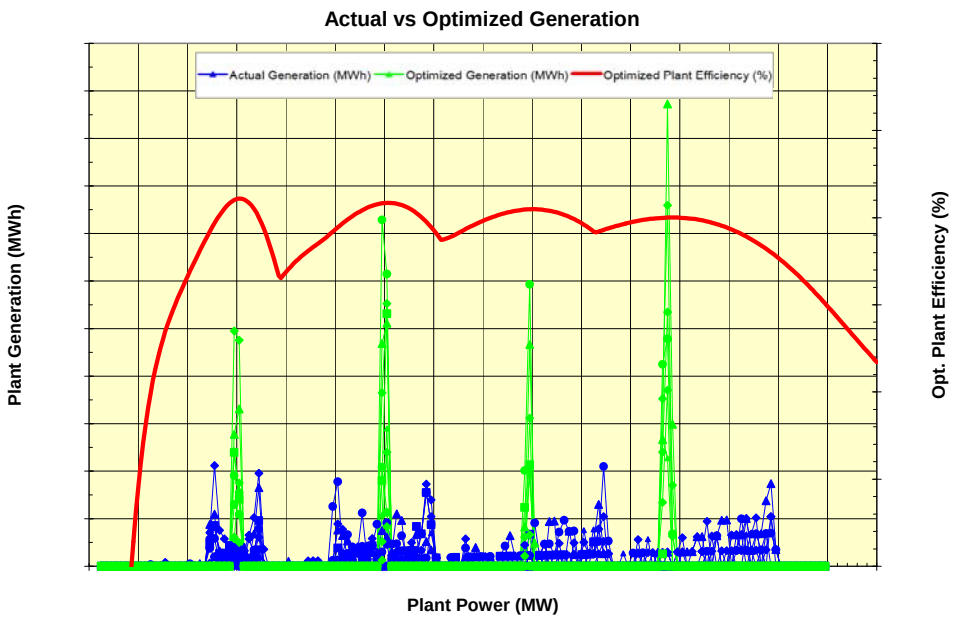

Figure 5-4: Typical Results from Scheduling Analyses (PS Plant Dispatched for Energy and Ancillary Services in a Vertically Integrated Power System)

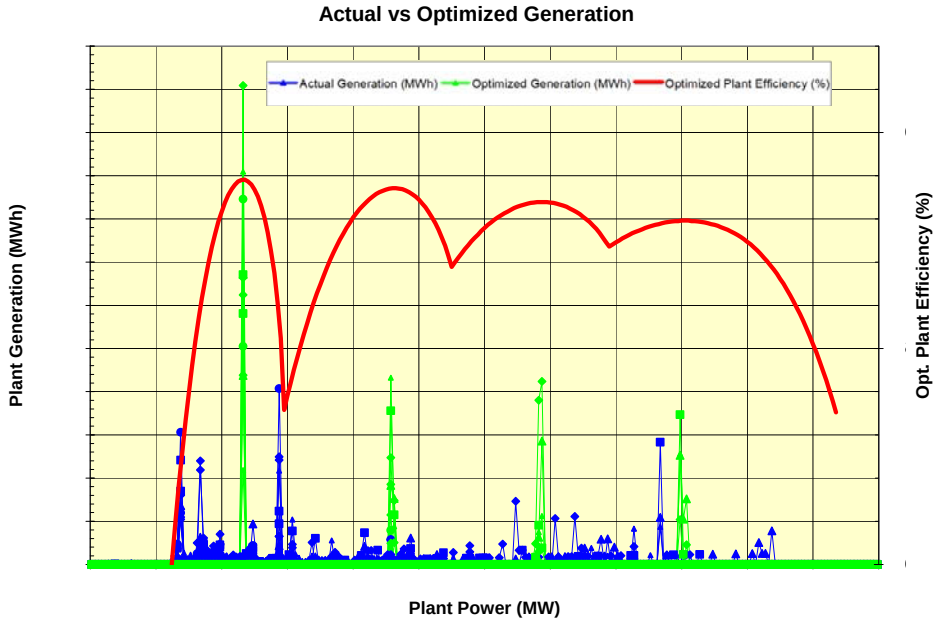

Figure 5-5: Typical Results from Scheduling Analyses (PS Plant Dispatched Primarily for Ancillary Services in an Established Market)

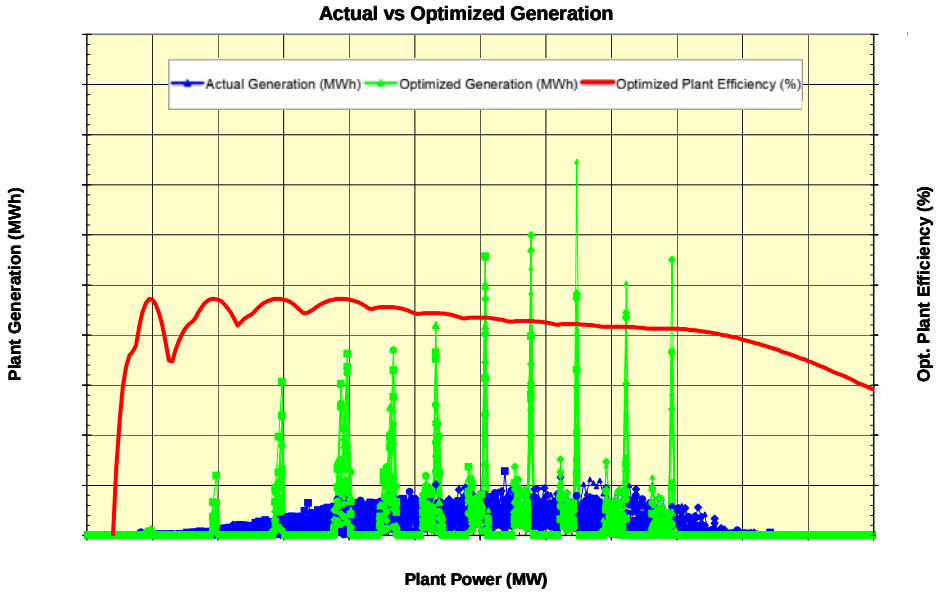

Figure 5-6: Typical Results from Scheduling Analyses (Conventional Plant Dispatched for Energy, Ancillary Services, and Flow in a Non-market Region)

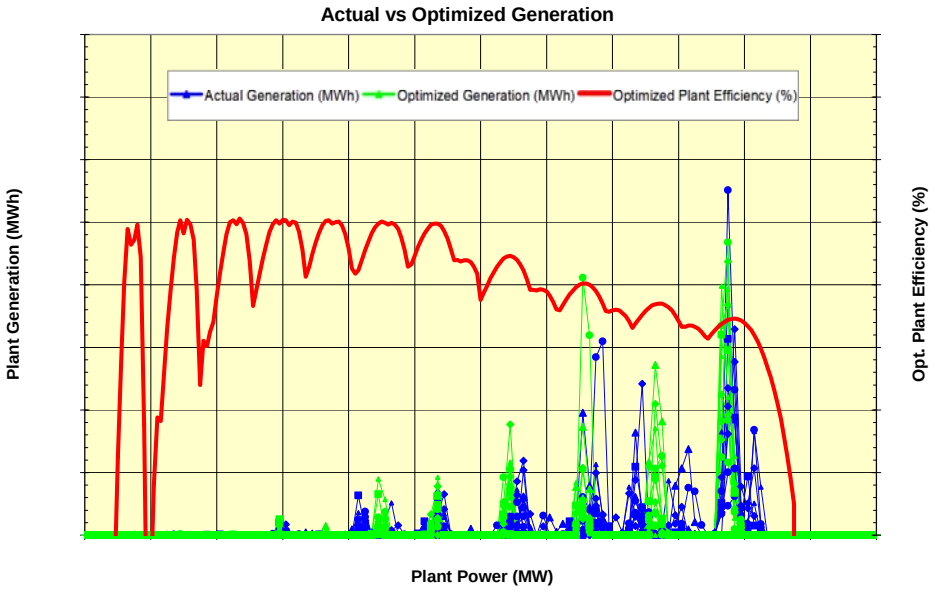

Figure 5-7: Typical Results from Scheduling Analyses (Conventional Plant Dispatched Primarily for Energy and Flow in an Established Market)

For all eight plants, quantitative analyses were conducted by using the unit performance characteristics, the optimized plant efficiency curves over the head range, and the archival plant data. The actual quantities of water used for generation per hour for the entire data set were computed. Those quantities of hourly "fuel" were applied to the optimized plant gross head efficiency curves for the appropriate heads to compute optimized generation for each hour. Results from the generation analyses for the pumped storage plants are provided in Table 5-3, and results from the generation analyses for the conventional plants are provided in Table 5-4.

For the pumped storage plant, the average for the potential plant generation improvements based on the generation scheduling analyses ranged from a low of 0.4% for Plant 2, which participates in an energy market and provides limited ancillary services (spinning reserve and offline supplemental reserve, but not regulation), to a high of 2.9% for Plant 3, which participates in both energy and ancillary services markets but is primarily dispatched by the market for ancillary services. For the conventional hydroelectric plants, the average for the potential plant generation improvements based on the generation scheduling analyses ranged from a low of 0.4% for Plant 8, which provides energy and ancillary services in a non-market region, to a high of 2.5% for Plant 6, which participates in both energy and ancillary services markets.

Table 5-3: Summary of Results from Generation Scheduling Analyses of Pumped Storage Plants

Plant	Computed Improvement (%) from Scheduling Analyses
1	1.0
2	0.4
3	2.9
4	0.9
5	0.4

Table 5-4: Summary of Results from Generation Scheduling Analyses of Conventional Hydroelectric Plants

Plant	Computed Improvement (%) from Scheduling Analyses
6	2.5
7	0.5
8	0.4

6: Comparisons of Results from Market and Non-market Plants

Overview – The five pumped storage plants and three conventional hydroelectric plants included in these analyses encompass three market regions (MISO, PJM, and NYISO) and two non-market regions (Southeast area and Western area). Owners for the eight plants include three investor-owned utilities, two state power authorities, and one federal power corporation.

Summary of Overall Results – Results from both operation efficiency analyses and generation scheduling analyses (see Section 5) are summarized by market or region for pumped storage plants in Table 6-1 and for conventional plants in Table 6-2. One plant was not included in the Table 6-1 results because the plant operates under unique constraints and does not provide regulation services.

Table 6-1: Summary of Results from Analyses of Pumped Storage Plants by Market/Region

Market Environment	Avg. Computed Improvement from Operation Eff. Analyses (%)	Avg. Computed Improvement from Scheduling Analyses (%)
Non-market Region	0.5	0.7
Market Region	1.0	1.9

Table 6-2: Summary of Results from Analyses of Conventional Plants by Market/Region

Market Environment	Avg. Computed Improvement from Operation Eff. Analyses (%)	Avg. Computed Improvement from Scheduling Analyses (%)
Non-market Region	0.5	0.4
Market Region	1.8	1.5

For the pumped storage plants, the average for the potential plant generation improvements based on the operation efficiency analyses (i.e., the suboptimization) was 0.5% for the non-market plants and 1.0% for the plants in the market regions. The average for the potential plant generation improvements based on the generation scheduling analyses was 0.7% for the non-market pumped storage plants and 1.9% for the pumped storage plants in the market regions.

For the conventional hydroelectric plants, the average for the potential plant generation improvements based on the operation efficiency analyses was 0.5% for the non-market plants and 1.8% for the plants in the market regions. The average for the potential plant generation improvements based on the generation scheduling analyses was 0.4% for the non-market plants and 1.5% for the plants in the market regions.

Example of Market-related Suboptimization – Figure 6-1 provides an example of market-related suboptimization for a pumped storage plant operating in a well-established market. In Figure 6-1, the colors of the lines follow this convention:

1. The red line represents the actual Unit 1 generation, and the dashed red line represents the optimized Unit 1 generation (left axis, MW for Unit 1);
2. The orange line represents the actual Unit 2 generation, and the dashed orange line represents the optimized Unit 2 generation (left axis, MW for Unit 2);
3. The yellow line represents the actual Unit 3 generation, and the dashed yellow line represents the optimized Unit 3 generation (left axis, MW for Unit 3);
4. The bright green line represents the actual Unit 4 generation, and the dashed bright green line represents the optimized Unit 4 generation (left axis, MW for Unit 4);
5. The dark green line represents the potential plant efficiency improvement from improved optimization while matching the actual plant power (right axis, % of total generation).

This plant's four units must be bid individually into the market. For much of the day, three individual units are dispatched by the market to operate near each unit's maximum capacity, when operation of four units at equal power levels near best efficiency would provide overall plant efficiency improvements of up to about 6%, corresponding to 285 MWh of increased generation (or conserved water) for the day.

A market change allowing the pumped storage plant to be bid into the market as a whole rather than as individual units would reduce this type of suboptimization. Alternatively, a "smarter" market could be designed, in which the market understands the performance

characteristics and limitations of the pumped storage plant and dispatches the plant accordingly.

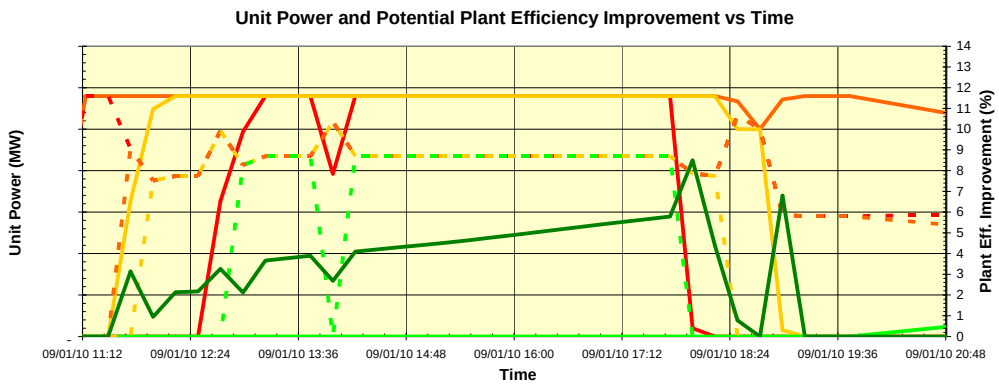

Figure 6-1: Operation Efficiency Results for a Pumped Storage Plant in a Market Region

Steady and Variable Operations – As presented above, results suggest that utilities in the non-market regions typically operate their pumped storage and conventional hydropower assets with less suboptimization (i.e., more efficiently) compared to utilities in market regions. Differences in ancillary services operations could be an important component of this. To provide insights into the differences between the market and non-market results, additional analyses of the 2008, 2009, and 2010 operation efficiency results (see Section 5) were conducted.

The following definitions assist in interpreting results from these additional analyses:

- Maximum Plant Power Level (MW) - The maximum plant power level (MW) determined from the 2008 - 2010 data;
- Average Operating Capacity (%) - The average power level (MW) for every time period of plant operation divided by the Maximum Plant Power Level (MW) and expressed as a percentage;
- Annual Capacity Factor (%) – The average total annual plant generation (MWh) divided by the product of the Maximum Plant Power Level (MW) and the number of hours in a year (h) and expressed as a percentage;
- LEO, Lost Energy Opportunity (MWh) – The potential generation improvement identified through the operation efficiency analyses;
- Power Variability (%) – The difference between the plant power level for an individual time step in the operation efficiency results and the plant power level for the previous time step, divided by the plant power level for the time step and expressed as a percentage.

For each of the eight plants, plant power values were sorted from low to high for each year, and plant power values less than 10% of the maximum plant power level were deleted to emphasize potential market effects by reducing the influence of fish flows and

minimum flows. Power variability values were then computed for each time step and sorted from high to low. Based on discussions with plant managers, all results with power variabilities less than 10% were sorted as "steady operation" values and all results with power variabilities of 10% or greater were sorted as "variable operation" values.

Table 6-3 provides a summary of results from these analyses comparing overall, steady, and variable operating conditions. In general, the filtered results include a high percentage of the overall data and closely resemble the unfiltered results.

Table 6-3: Summary of Operation Efficiency Results for Overall, Steady, and Variable Operations of Pumped Storage and Conventional Plants

Comparison of Operation Efficiency Results for Overall, Steady, and Variable Operations

Description	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7	Plant 8
Overall Operating Capacity (%)	45.5	64.1	23.2	45.4	46.2	40.3	40.5	48.9
Overall Annual Capacity Factor (%)	13.7	13.4	4.2	17.9	18.4	38.1	38.5	48.8
Filtered Avg. Operating Capacity (%)	45.7	64.1	23.3	46.6	46.2	65.0	64.3	50.7
Filtered Generation/Total Generation (%)	100.0	99.9	99.8	98.2	99.9	95.8	93.4	99.3
Filtered LEO/Total LEO (%)	100.0	100.0	99.8	99.3	99.9	93.4	83.9	96.6
Overall LEO/Total Generation (%)	0.46	0.01	0.93	1.07	0.40	2.70	0.94	0.50
Filtered LEO/Filtered Generation (%)	0.46	0.01	0.93	1.08	0.40	2.63	0.82	0.48
Variable LEO/Variable Gen (%)	0.39	0.06	1.08	1.08	0.44	3.53	1.20	0.79
Steady LEO/Steady Gen (%)	0.49	0.01	0.84	1.09	0.38	2.38	0.80	0.39
Average Variable Operating Capacity (%)	39.9	64.6	24.8	45.7	42.8	53.5	50.8	37.8
Average Steady Operating Capacity (%)	49.0	60.4	22.5	47.3	48.7	68.7	65.1	56.5

For the pumped storage plants, the overall operating capacities range from 23.2% to 64.1%, and the annual capacity factors range from 4.2% to 18.4%. For the conventional plants, the overall operating capacities range from 40.3% to 48.9%, and the annual capacity factors range from 38.1% to 48.8%. The steady and variable operating capacities are relatively close for the pumped storage plants, but the steady operating capacities for the conventional plants are 14% to 19% higher than the variable operating capacities.

The power level variability ranges derived from the sorted data are provided in Figure 6-2. Plant 2 and Plant 7 showed the least variability. Although both of these plants are in market regions, they are not operated for load regulation.

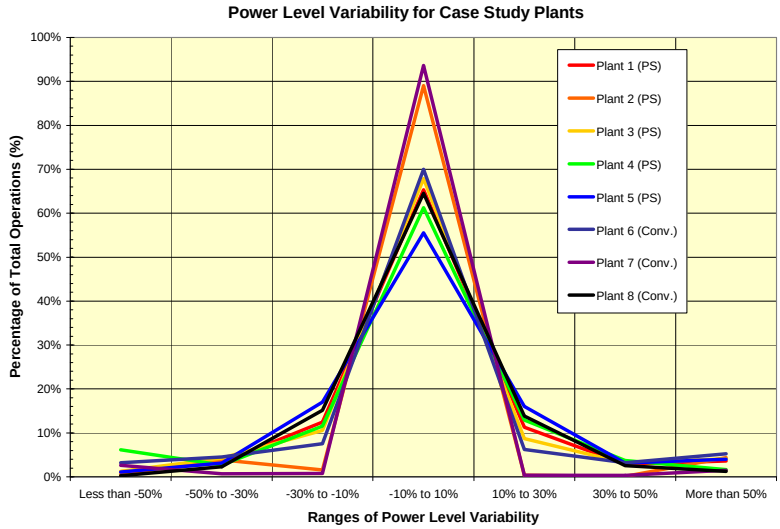

Figure 6-2: Power Level Variability for Case Study Plants

Operation efficiency results under overall, steady, and variable operating conditions are summarized by market and non-market regions in Table 6-4 and by individual plant in Figure 6-3.

Table 6-4: Summary of Operation Efficiency Results for Market and Non-market Operations of Pumped Storage and Conventional Plants

Market Environment	Total LEO divided by Total Generation (%)	Steady LEO divided by Steady Generation (%)	Variable LEO divided by Variable Generation (%)
Non-market Region	0.45	0.42	0.54
Market Region	1.41	1.28	1.72

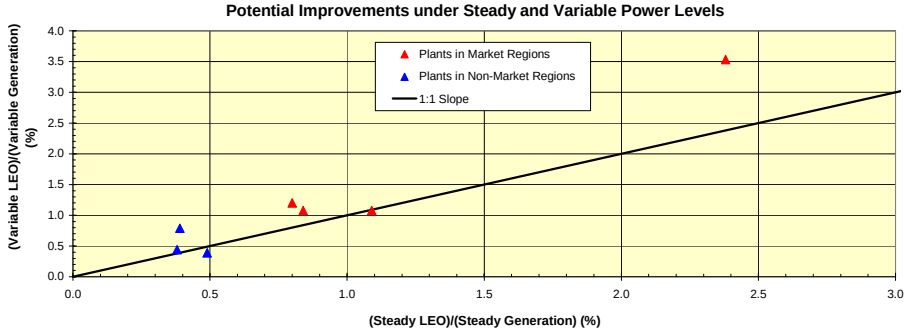

Figure 6-3: Operation Efficiency Results for Market and Non-market Operations under Steady and Variable Operating Conditions

Both Table 6-4 and Figure 6-3 show that the plants in non-market regions are operating with less suboptimization (i.e., more efficiently) under both steady and variable conditions when compared to the plants operating in market regions. In addition, the suboptimization under variable conditions is typically higher than the suboptimization under steady conditions for plants in both market regions and non-market regions. Under both steady and variable generation, the potential efficiency improvements for the market plants are about three times as large as the potential efficiency improvements for the non-market plants.

The analyses summarized in Table 6-4 are typically based on plant operational data at fifteen-minute intervals. For one of the plants, which is operated in a market region for energy and ancillary services, performance analyses were also conducted for January 2010 and June 2010 using plant operational data at one-minute intervals. Table 6-5 compares the results from one-minute analyses and fifteen-minute analyses for these two months. Although based on a limited comparison at only one plant, these results suggest that the higher time resolution can identify significant additional suboptimization, particularly for variable operations.

Table 6-5: Comparison of Time Scales of Operation Efficiencies for Overall, Steady, and Variable Operations (Conventional Plant, January and June 2010)

Comparison of Time Scales for Operational Data (Jan. and June, 2010)			
Time Scale for Data	**Total LEO divided by Total Generation (%)**	**Steady LEO divided by Steady Generation (%)**	**Variable LEO divided by Variable Generation (%)**
1-minute	3.00	2.85	4.82
15-minute	2.95	2.66	3.75

7. Operations-related Results from Performance Analyses

Overview – This section discusses operations-related results from the detailed performance analyses. Discussion is organized by several categories, including flow measurements, operators and control systems, environmental operations, and avoidable losses.

Flow Measurements for Operational Purposes – Accurate unit and plant performance characteristics are essential for proper plant operation. Flow measurement is a key component of accurate unit and plant performance characteristics, and improved attention to unit flow measurements can improve operational efficiencies and generation.

When continuous measurements of relative or absolute flow rate are available for each unit of a plant, correlation analyses can be computed to compare the measured unit performance with the expected unit performance. However, for the five pumped storage

plants and three conventional hydroelectric plants examined, potentially usable flow data was only available for one plant.

Flow data for this plant, measured using acoustic flowmeters, was used to compute correlation efficiencies. The typical correlation efficiencies during January 2010 for this plant are shown in Figure 7-1.

The lowest correlation efficiency (i.e., the lowest correlation between the measured flows and the expected flows) is for Unit 2, followed by Unit 1. In Figures 7-2 and 7-3, the flow versus power curves expected from the unit performance characteristics (red curves) are compared to the flows measured with the acoustic flowmeters for Unit 2 and Unit 1 and the corresponding power values for Unit 2 and Unit 1. In general, the measured flow values for Unit 2 and Unit 1 exhibit a considerable amount of scatter, fall below the expected values, and do not follow the expected curve shape.

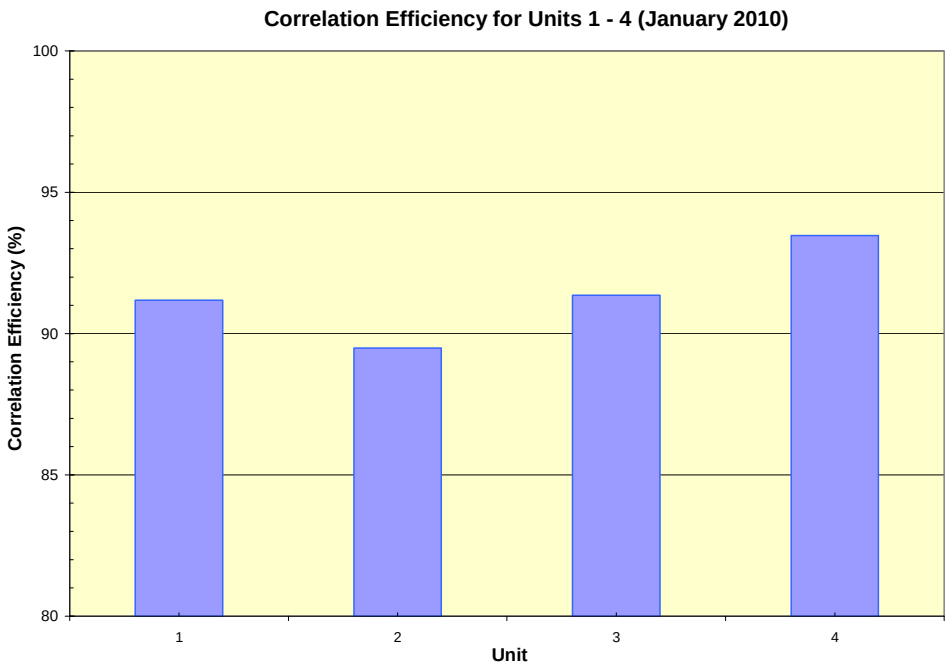

Figure 7-1: Typical Correlation Efficiencies, Units 1 - 4 (January 2010)

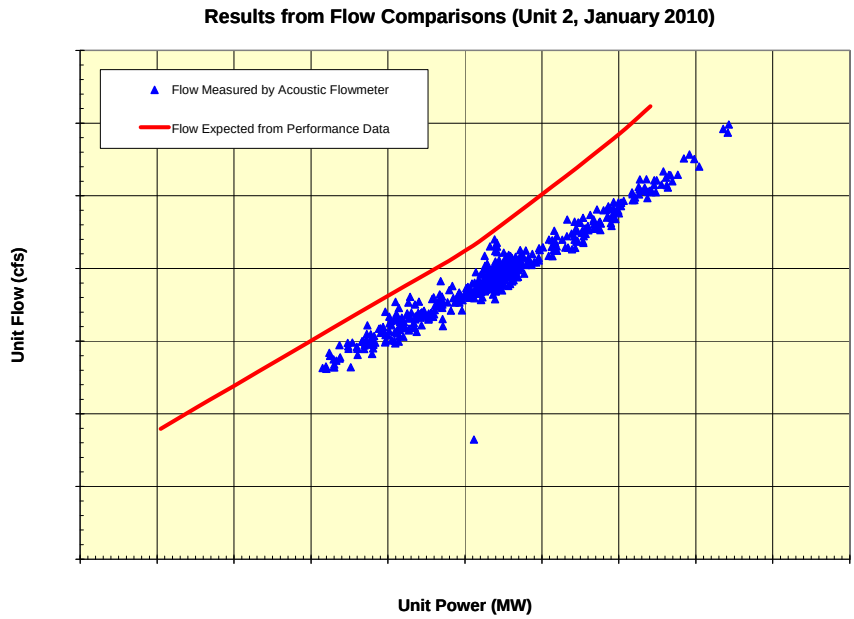

Figure 7-2: Expected Flow and Measured Flow versus Power (Unit 2, January 2010)

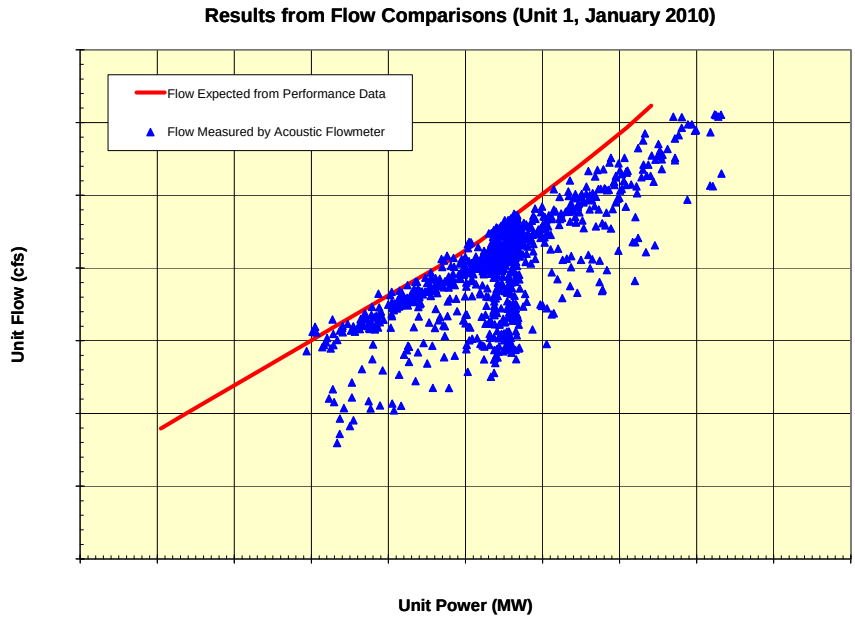

Figure 7-3: Expected Flow and Measured Flow versus Power (Unit 1, January 2010)

The highest correlation efficiency (i.e., the highest correlation between the measured flows and the expected flows) in Figure 7-1 is for Unit 4. Figure 7-4 compares the flow versus power curve expected from the unit performance characteristics (red curve) to the

flows measured with the acoustic flowmeters for Unit 4 and the corresponding power values for Unit 4.

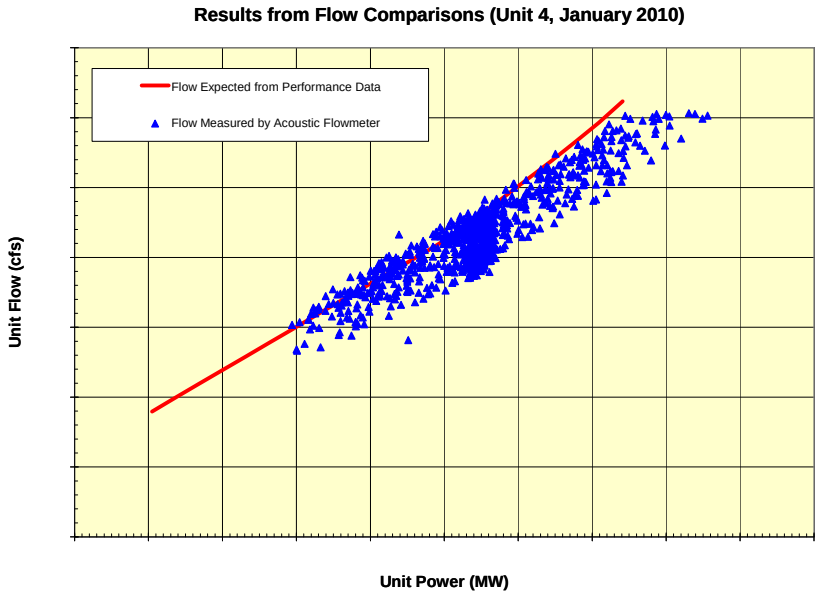

Figure 7-4: Expected Flow and Measured Flow versus Power (Unit 4, January 2010)

The measured flows scatter around the expected flows over the middle of the unit performance curve but fall below the curve at higher values of power and flow. In addition, the data from the Unit 4 acoustic flowmeter also scatters widely, similar to the data from other units as shown in Figures 7-2 and 7-3. This could be due to a variety of causes, such as inadequate maintenance. The correlation analyses provide an indication of problems associated with the flow data and/or the flow-related instrumentation.

Operational Control – The five pumped storage plants and three conventional hydroelectric plants examined in this paper vary in their degree of automation. However, all of the plants include both human operators and sophisticated control systems. Four of the plants utilize operational rules embedded in the control systems, and four of the plants include optimization software integrated into the control systems. Table 7-1 compares the suboptimization for the rule-based systems with the suboptimization for the systems with integrated optimization.

Table 7-1: Summary of Suboptimization from Analyses of Pumped Storage and Conventional Plants by Optimization Method

Optimization Method	Total LEO divided by Total Generation (%)	Steady LEO divided by Steady Generation (%)	Variable LEO divided by Variable Generation (%)
Rules in Control System	1.36	1.24	1.67
Optimizer Integrated into Control System	0.73	0.67	0.88

The plants with optimizers integrated into the control systems operate more efficiently than the plants incorporating optimization rules in the control systems under both steady and variable generation conditions. Under both steady and variable generation, the suboptimization for the plants using control system rules is about two times greater than the suboptimization for the plants with integrated optimization systems. Interestingly, this difference is less than the three times factor observed in comparing market plants with non-market plants (see Section 6).

Several examples of suboptimization are provided in Figures 7-5 and 7-6. In these figures, the colors of the lines follow this convention:

1. The red line represents the actual Unit 1 generation, and the dashed red line represents the optimized Unit 1 generation (left axis, MW for Unit 1);
2. The orange line represents the actual Unit 2 generation, and the dashed orange line represents the optimized Unit 2 generation (left axis, MW for Unit 2);
3. The yellow line represents the actual Unit 3 generation, and the dashed yellow line represents the optimized Unit 3 generation (left axis, MW for Unit 3);
4. The bright green line represents the actual Unit 4 generation, and the dashed bright green line represents the optimized Unit 4 generation (left axis, MW for Unit 4);
5. The dark green line represents the potential plant efficiency improvement from improved optimization while matching the actual plant power (right axis, % of total generation).

Figure 7-5 shows a full day's generation on June 25, 2010, for one of the pumped storage plants. On this day, the plant's power level varied by about 100 MW from 10:30 AM to 12:45 PM, with three units operating at unequal loads. From 1:00 PM to 6:00 PM, the plant power level increased by several hundred MW and varied by about 200 MW, with four units operating at unequal loads. From 6:15 PM to 8:45 PM, the plant power level dropped and varied by about 200 MW, with three units operating at unequal loads. During almost all of the three unit operation, the optimized operation requires four units. The combination of having the correct number of units online and having the load equally distributed among the units would provide plant efficiency improvements of up to 4.0%, corresponding to 184 MWh of increased generation (or the equivalent conserved water in the upper reservoir) for the day.

Figure 7-6 shows a period of operation on July 13, 2010, for a different pumped storage plant. From 4:30 PM to 8:15 PM, the plant power level varied by about 200 MW, with four units operating at approximately equal loads. For most of the four-unit operation during this period, the operation efficiency results recommend three-unit operation, providing plant efficiency improvements of up to 1.7% and corresponding to 62 MWh of increased generation (or the equivalent conserved water in the upper reservoir) for the time period.

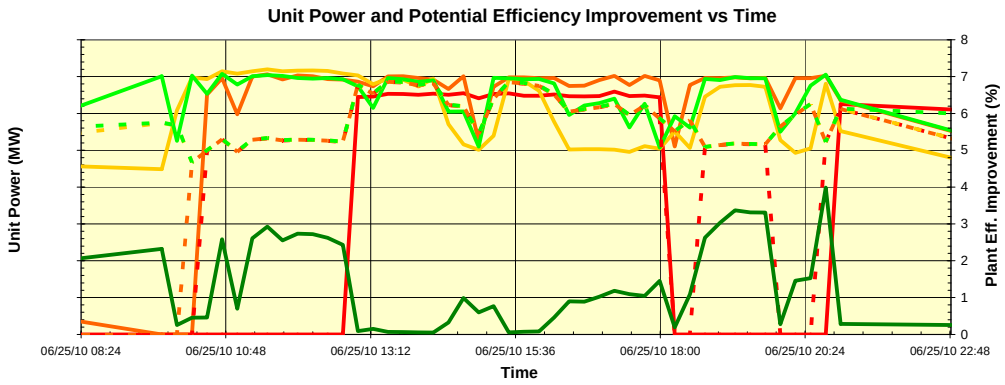

Figure 7-5: Typical Operation Efficiency Results (June 25, 2010)

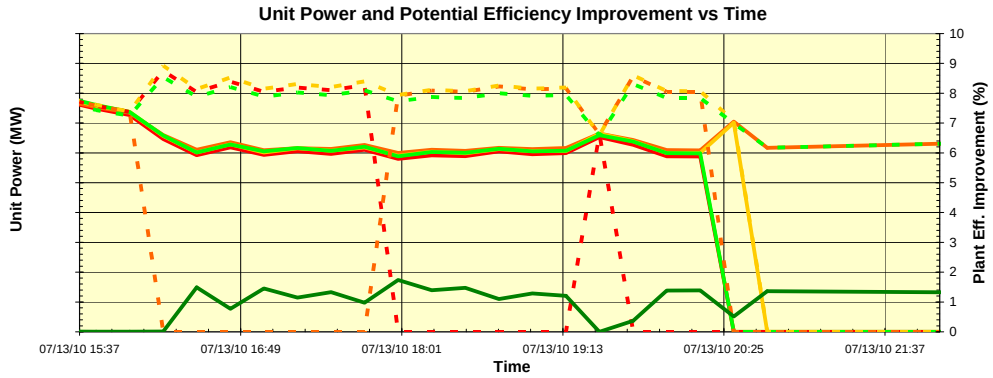

Figure 7-6: Operation Efficiency Results (July 13, 2010)

Environmental Operations – Figure 7-7 provides an example of operational problems associated with providing minimum flows at one of the conventional hydroelectric plants. This plant typically meets its minimum flow requirements by operating one of the most efficient units. During a two-month period, however, an "efficiency excursion" occurred when the plant's minimum flow requirements were met using two units instead of one, due to multiple reliability concerns including debris in one unit's spiral case.

Figure 7-7 shows operation efficiency results and provides an example of the typical daily operations during this period. In Figure 7-7, the colors of the lines follow this convention:

1. The red lines represents the actual generation for one family of similar units, and the dashed red lines represents the optimized generation for the family of units (left axis, MW for each unit);

2. The gold lines represents the actual generation for another family of similar units, and the dashed orange line represents the optimized generation for this second family of units (left axis, MW for each unit);

3. The blue lines represents the actual generation for a third family of similar units, and the dashed blue lines represents the optimized generation for this third family of units (left axis, MW for each unit);

4. The dark green line represents the potential plant efficiency improvement from improved optimization while matching the actual plant power (right axis, % of total generation).

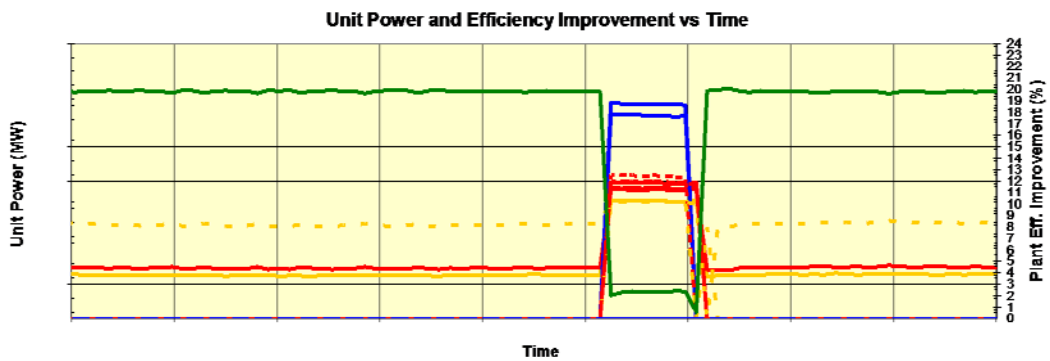

Figure 7-7: Example Showing Suboptimization Associated with Meeting the Minimum Flow Requirement at a Conventional Hydroelectric Plant

Because the minimum flow is provided by two units instead of one unit, there are significant periods when the efficiency improvement potential is about 20%. The largest Lost Energy Opportunity for a single day is 193 MWh, and the total Lost Energy Opportunity for this period of two unit minimum flow operation is 8,136 MWh.

Another conventional hydroelectric plant's operation is based on market requirements for energy and ancillary services. This plant's operation is also constrained by environmental requirements, including dissolved oxygen (DO) and total dissolved gas (TDG) levels, which affect the specific units that operate and the number of operating units. Operating efficiency results for 2010 were analyzed for this plant to compare suboptimization during "normal" operations (January 1 through May 31 and October 16 through December 31) and during "environmental" operations (June 1 through October 15). Table 7-2 compares overall results with results under steady and variable operating conditions.

Table 7-2: Summary of Suboptimization from Analyses of Conventional Plant under Normal and Environmental Operations

Comparison of Suboptimization under Normal and Environmental Operations			
Operational Mode	**Total LEO divided by Total Generation (%)**	**Steady LEO divided by Steady Generation (%)**	**Variable LEO divided by Variable Generation (%)**
Normal Operations	2.72	2.41	3.44
Environmental Operations	2.98	2.53	3.55

This plant operates somewhat more efficiently under normal operations than under environmental operations for both steady and variable generation conditions. In addition, the plant operates more efficiently under steady generation conditions compared to variable conditions for both normal operations and environmental operations. However, even "normal" operations at this plant are affected by environmental requirements, particularly the TDG limit. Significant benefits could be achieved at the plant through improved optimization, including improved environmental optimization.

Additional Operations-related Issue (Avoidable Trash Rack Losses) – Avoidable loss analyses can be used to determine how plant generation could be improved by reducing avoidable losses. Avoidable losses typically include excessive trash rack losses, excessive penstock losses, excessive tunnel losses, and excessive spill. The computational steps for these analyses are explained elsewhere [DOE, 2011]. For the five pumped storage plants and three conventional plants included in this paper, data was available from one conventional plant to provide an evaluation of avoidable trash rack losses.

Plant personnel provided measurements of the head differentials between the forebay and the spiral case for each unit. The head differential measurements, the flows determined from unit characteristics, and the operational data from 2008 through 2010 were used to compute the baseline "clean rack" loss coefficient for each unit and the head losses associated with the trash rack fouling for each unit.

Figure 7-8 provides the total annual energy losses associated with the avoidable trash rack losses for this plant. The estimated trash rack energy loss over the three-year analysis period is 103,793 MWh.

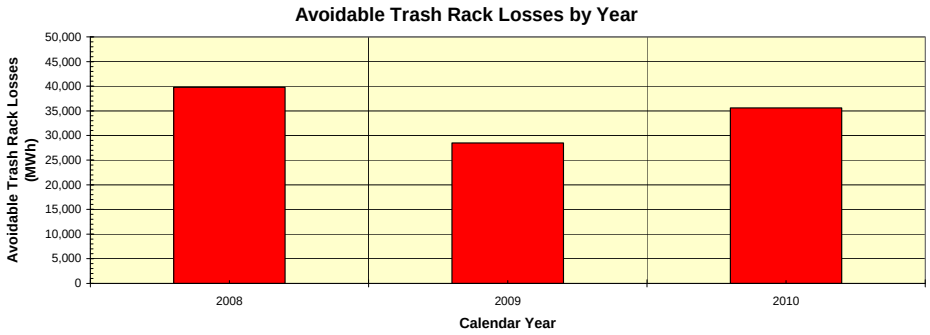

Figure 7-8: Summary of Avoidable Trash Rack Energy Losses (2008 – 2010)

It is likely that avoidable trash rack losses exist at some of the other seven plants, but data was only available to evaluate one plant.

8. Conclusions and Recommendations

This paper summarizes results from optimization-based performance analyses conducted for five pumped storage plants and three conventional hydroelectric plants as part of the EPRI/DOE Hydropower Grid Services Project and results from additional analyses of the performance data.

Conclusions and recommendations based on these results are listed below:

1. Accurate unit and plant performance characteristics are essential for proper plant operation. Improved attention to unit flow measurements can improve operational efficiencies and generation.

2. The potential generation improvements from direct optimization, while producing the same power at the same time, ranged from a low of 0.01% to a high of 1.1% for the pumped storage plants and from a low of 0.5% to a high of 2.7% for the conventional plants. Much of this potential generation increase for these plants may be cost-effectively achievable through automation, optimization, and control system improvements. Due to the high levels of annual generation at these plants, even a fractional percentage of improvement has significant economic value.

3. The potential generation improvements due to improved scheduling ranged from a low of 0.4% to a high of 2.9% for the pumped storage plants and from a low of 0.4% to a high of 2.5% for the conventional plants.

4. The potential generation improvements from direct optimization, while producing the same power at the same time, averaged 0.5% for the pumped storage plants in non-market regions and 1.0% for the pumped storage plants in the market regions. The potential generation improvements from direct optimization averaged 0.5% for the conventional plants in the non-market regions and 1.8% for the conventional plants in the market regions.

5. With results combined for pumped storage and conventional plants, the potential generation improvements from direct optimization, while producing the same power at the same time, averaged 0.42% for the plants in non-market regions and 1.28% for the plants in the market regions under steady operating conditions and 0.54% for the plants in non-market regions and 1.72% for the plants in the market regions under variable operating conditions.

6. A limited comparison of fifteen-minute data and one-minute data at one plant suggests that the higher time resolution can identify significant additional suboptimization, particularly for variable operations.

7. The potential generation improvements due to improved scheduling averaged 0.7% for the pumped storage plants in non-market regions and 1.9% for the pumped storage plants in the market regions. The potential generation improvements due to improved scheduling averaged 0.4% for the conventional plants in the non-market regions and 1.5% for the conventional plants in the market regions.

8. Results show that utilities in non-market regions typically operate their pumped storage and conventional hydropower assets with less suboptimization (i.e., more efficiently) compared to utilities in market regions. Under both steady and variable generation, the potential efficiency improvements for the market plants average about three times as large as the potential efficiency improvements for the non-market plants. However, the sample size is small, and numerous differences exist among the plants, the utilities, and the regions. Additional investigation is warranted.

9. Opportunities may also exist for market improvements to reduce suboptimization, particularly suboptimization of pumped-storage plants. For example, a "smarter" market could be designed to understand the performance characteristics and limitations of a pumped storage plant and dispatch the plant accordingly.

10. Under both steady and variable generation, the plants with optimizers integrated into the control systems operate more efficiently than the plants incorporating optimization rules in the control systems. The suboptimization for the plants using control system rules is about two times greater than the suboptimization for the plants with integrated optimization systems.

11. Operation efficiency analyses for a conventional plant with significant environmental requirements, including mandated DO and TDG levels, show that the plant operates more efficiently under normal operations than under environmental operations for both steady and variable generation conditions. In addition, the plant operates more efficiently under steady generation conditions compared to variable conditions for both normal operations and environmental operations. Significant benefits could be achieved at this plant through improved optimization, particularly through improved environmental optimization.

12. Opportunities exist for cost-effective plant improvements to reduce avoidable losses, such as trash rack losses, for conventional hydroelectric plants.

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