Optimization of Idaho Power Company’s Hydro Assets

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ABSTRACT

Preliminary in-house research indicated large gains could be realized by applying optimization techniques to the planning process for the three dam Hell’s Canyon Complex. Instead of a formal process involving requests for proposals, evaluations, and then purchase agreement, Idaho Power pursued an alternative method of selecting optimization software. After interviews and site visits, a vendor was selected to conduct a pilot project. Upon favorable completion of the pilot project, a permanent system would be purchased. Verification methods, case studies and permanent system implementation are discussed.

Introduction

Idaho Power Company’s Hydro Production Department developed a real-time plant optimization tool to account for lost generation at the larger, load-following plants located in the Hell’s Canyon Complex. During implementation of this program it was recognized that if optimization was continued from real-time into the pre-schedule, or day-ahead process, additional gains could be realized.

Optimizing the real-time and day-ahead schedules required a new software system that could accommodate multiple plants and reservoirs and must include generation sources such as thermal, co-generation and run-of-river hydro plants. Several software applications were in use by the planning and scheduling groups, but these groups and their applications were poorly coordinated. Four options existed; develop an in-house application, modify existing models in use by other departments, upgrade the existing energy management system (EMS), or purchase a new supplementary software system.

Optimization Provider Decision

During information gathering and vendor reviews, goals for the optimization program were expanded to include integration of all short and long-term planning and scheduling activities. This change shifted the program from optimizing generation to optimizing the net effect of generation and transactions. Any future software system had to accommodate the needs of both utility planners concerned with longer-term issues and affiliate traders concerned with short-term schedules. In summary the project now had the following goals:

- Determine a financial method to benchmark performance of the operations plan with respect to forecasts and physical constraints.
- Integrate major aspects of the operations plan such that short-term and long-term operations were consistent, the new software system must tie long-term reservoir operation to the real-time and pre-schedule functions.

Idaho Power Company (IPCo) did not have the ability to develop its own software system and review of the other hydro models revealed averaging techniques that couldn't be used for scheduling. This left two options, either upgrade the EMS or purchase a new system. The EMS upgrade option offered a smaller project and "closed loop" control meaning that the solution from the optimal computer run would be fed directly into the generator control loop. The EMS upgrade option did not provide analysis features to conduct generation asset studies, and the upgrade option did not address long-term and short-term scheduling integration. These missing options were available from new systems. For these reasons IPCo chose to further investigate and ultimately purchase Synexus Global's VISTA Decision support software.

Pilot Project

Successful integration of optimizing software into the planning organization is difficult. The software may only provide marginal benefits or non-practical schedules because the hydro system is complex or overly constrained, the utility organization may not be sophisticated enough to utilize the software, or the software may not be flexible or responsive enough for both short-term and long-term market applications. As a means to determine Idaho Power Company's ability to integrate the proposed software system and to estimate the financial value, a pilot project was conducted during the spring of 2002.

Pilot- Physical Model

Due to time constraints a model was developed representing a simplified generation and transmission system. This abbreviated model captured Idaho Power Company's only seasonal reservoir, the largest hydro resources, and lumped multiple transmission lines to one market path. Base loaded thermal, run of river hydro, and Co-Generation

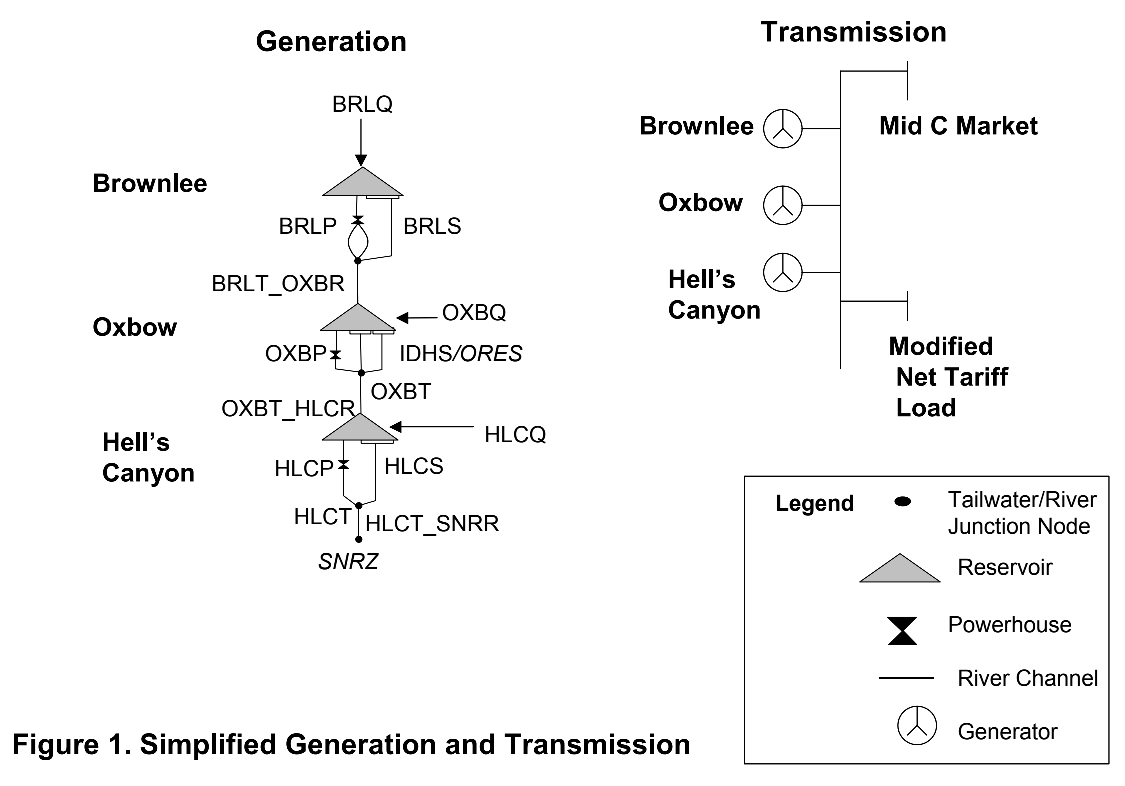


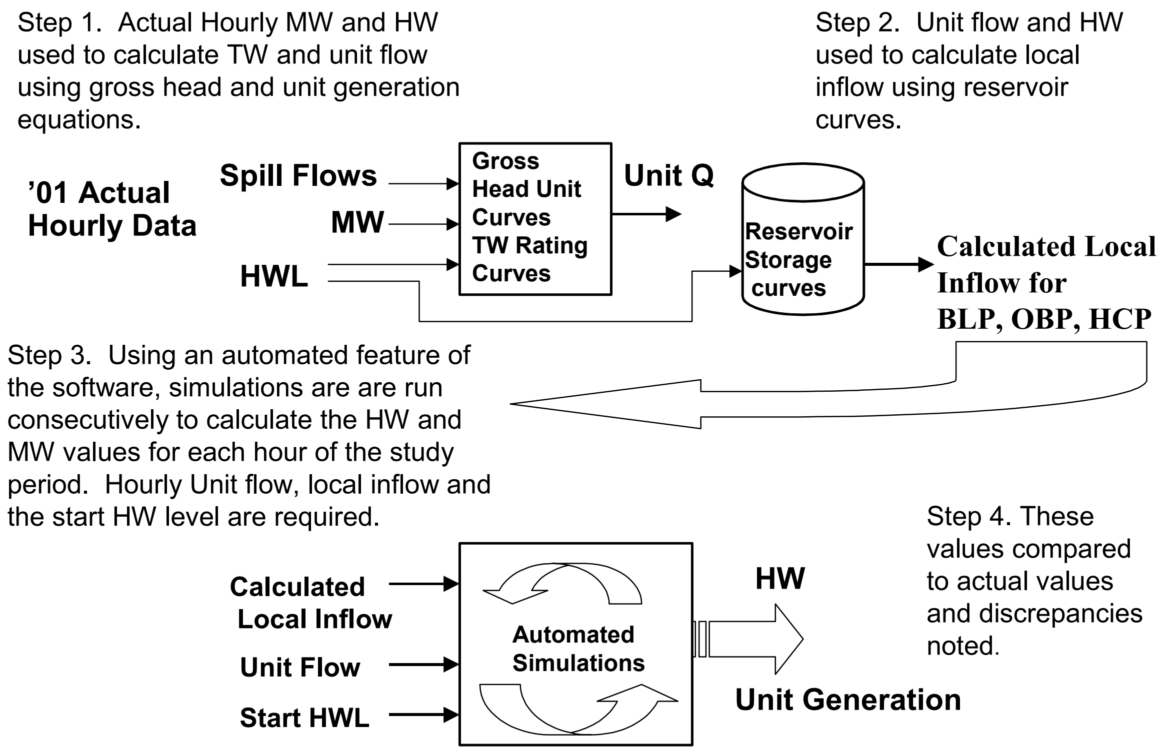
Figure 1. Simplified Generation and Transmission

resources were subtracted from system load. This reduced the number of generation sources to model and reduced input for loads to one, modified net tariff load. Transmission was simplified to a single bus connecting net tariff load, generation, and the Middle Columbia (Mid C) energy market and included capacity restrictions to the market. Available purchases and sales were entered as one flexible contract source tied to the Mid C bus.

The generation model shown in Figure 1 captures the Hells Canyon Complex but does not capture smaller Upper Snake hydro plants that are not strictly run-of-river. Energy markets to the south and east of the Idaho Power Service Territory were also omitted. These omissions detract from any derived value the software could provide and can be added to a permanent version, therefore, any financial benefits determined by the pilot project will be conservative.

Pilot -Model Verification

To determine if the optimization software could model the Hells Canyon Complex adequately, a method was developed to verify computational accuracy regarding generation, inflow, and water levels. Simulated values were then checked with actual values. Year 2001 hourly values for unit generation, spill flows, and headwater level (HWL) were used to calculate hourly values of unit discharge, tailwater level, and then local inflow. Local inflow, unit discharge, and starting (HWL) are then fed back into an automated simulator to determine hourly generation and HWL for the year. Figure 2 is a graphical representation of the verification method. This procedure may seem redundant or unnecessary, but a number of important issues were uncovered and corrected. The automated simulator, which takes the previous weeks solution as the


Step 1. Actual Hourly MW and HW used to calculate TW and unit flow using gross head and unit generation equations.

Step 2. Unit flow and HW used to calculate local inflow using reservoir curves.

Step 3. Using an automated feature of the software, simulations are are run consecutively to calculate the HW and MW values for each hour of the study period. Hourly Unit flow, local inflow and the start HW level are required.

Step 4. These values compared to actual values and discrepancies noted.

Figure 2. Verification Method

starting values for the next week, identifies small deviations that would not have been otherwise detected. These deviations if left unchecked, will cause discrepancies between future optimized schedules and the resulting actual values leading to a loss of confidence in the software. Deviations between calculated and actual values were rectified by correcting Oxbow turbine and tailwater rating curves, and by modifying the code to accept unit flow instead of unit generation as an input to the automated simulations. At completion of the verification process, calculated generation values were within .02% of actual annual total generation, and calculated HWL were within .001 ft of actual levels. Calculated inflow deviated from actual inflow by 2.88% on an annual volumetric basis. The model must calculate inflow because using actual inflow is not accurate enough by modeling standards. Calculated inflow will deviate from actual inflow because of uncertainty in river discharge and HWL measurements, deviations in actual turbine performance compared to curve predictions, and SCADA input errors. Without the use of this inflow technique the calculated values for HWL and generation would not match actual values.

Pilot - Projected Financial Return

As a regulated utility our obligation is to meet tariff load. Since tariff load is met through a combination of generation resources and market transactions, a maximizing value can be used as the sum of these actions. The software system optimizes operations by maximizing the objective function. For our purposes the objective function can be thought of as a value term,
Where Value = Sales-Purchases.

The entire optimization process can be summarized by the above objective function and one constraint…Meet Tariff Load

If the above constraint is satisfied, this maximizing function also becomes the benchmark value for the operations plan.
How do you really evaluate scheduling software using past information without the hindsight is perfect argument? How can you quantify future value from a product that only supports decision-making? These questions are especially relevant after considering that much of the uncertainty regarding scheduling, such as uncertain loads, market stability, resource reliability, is not addressed by the proposed system. As a means to estimate future value with the preceding questions in mind, a case study was performed using year 2001 information. Four cases were modeled in order to make value comparisons. Each case with exception of the base case had the following attributes:

- Actual inflow was entered into a short-term (ST) scheduling module simulating the use of more accurate short-term inflow forecasts for the one-week ahead schedule.
- Actual system load was used in lieu of forecasts to produce the net tariff load.
- Monthly Mid C forward price curves adjusted for transmission costs were used.
- Inflow forecasts used by the long-term (LT) Module (worst, low, expected, high), and resource constraints were entered for each month.

Base Case- This case is simply the hourly schedule generated from the verification step and shown to be the same as actual hourly generation. Since actual inflow is 2.88% greater, all other cases will have a 2.88% generation deduction on an hourly basis at the completion of the case run.

Perfect Case- Actual Inflow and actual prices fed into the automatic long-term and short-term (LT-ST) scheduling routine. The long-term (LT) module sees actual inflow and prices then passes the optimal weekly ending water level to the short-term optimizing module. The ST module then schedules the machines at optimal loadings with respect to prices, loads and inflow. This is the Hindsight is 20-20, or theoretically best case. This case establishes the upper theoretical limit, but cannot be used for comparisons of potential future value.

12 Month Case-Inflow and price forecasts were input into the automated LT-ST routine, but instead of running the routine for 52 consecutive weeks, the routine is run for 4 to 5 weeks. At the conclusion of this “run”, updated monthly forecast information along with the ending water levels from the previous run initiate the next month. This process is repeated for each of the 12 months, representing an operations plan with long-term planning governed by monthly corrections, and a short-term schedule governed by the long-term reservoir targets. Just as with the Perfect Case, the LT module sets end of week target levels for the ST module, but in this case the targets are based on forecasted information simulating typical utility operations. The ST module used actual Mid C daily average prices during the first two iterations simulating Day Ahead and Balance of Month activities, which are more accurate, compared to future month forecasts. The benefit of real time trading is excluded because the model did not have real time price information.

1 Forecast Case- January inflow and price forecasts are input into the automated LT-ST module. This represents using only one long-term forecast for price and inflow for the entire year. This is the worst-case scenario and should be the bottom tier of the case comparisons, with the 12 Month and Base Case falling between the Perfect and 1 Forecast Cases.

Case Results- On an hourly basis, value was calculated from generation and load as shown in Figure 3. The hourly running total of value for year 2001 is plotted in Figure 4. A significant year-end difference between actual and the 12 Month Case value functions was recorded. Of particular concern was the Base Case falling below the 1-Forecast Case, clearly indicating need for improvement. In a sense the model “got lucky”, in that, the January price forecast predicted market conditions during the spring more accurately than subsequent forecasts. This effect can be viewed in Figure 4 during the first few months when the 12 Month value is less than the 1 Forecast value. Note however, that the end of period (year) 12 Month value exceeded the 1 Forecast value as a result of updated monthly forecasts. The Base Case used actual inflows and was affected by load following and reserve compliance. These costs were applied to the other cases to keep the comparison valid. The benefits of reacting to real time price

Sales: (Surpluses) (Generation – Net Tariff Load) * Actual Sales Price
Purchases: (Deficits) (Net Tariff Load- Generation)* Actual Purchase Price
Value = Sales - Purchases

Figure 3. Definition of value

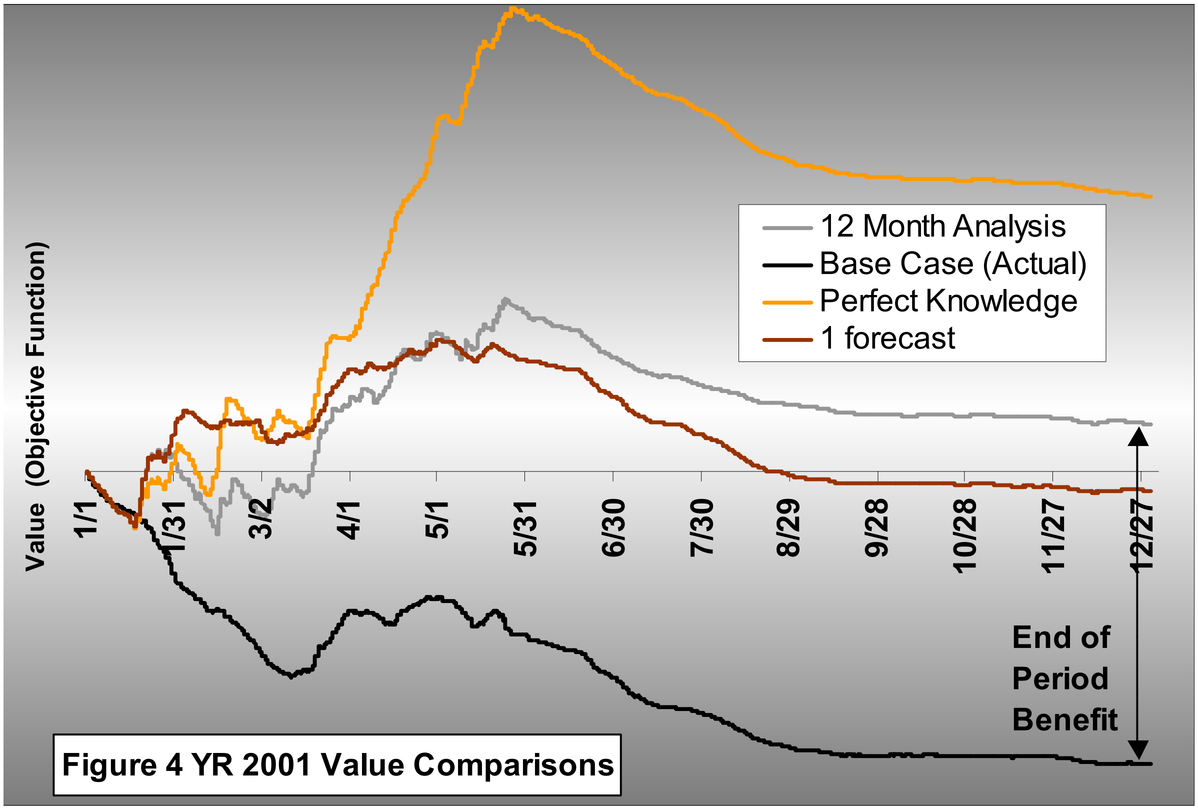


Figure 4 YR 2001 Value Comparisons

fluctuations, and the detriment of voltage support activities have been omitted in the comparison. Generation details for each case are shown in Figure 5.

Where did the additional value come from? 82% of the gain resulted from timing generation at higher priced periods relative to the future value of storage, and 18% of the gain resulted from increased heavy load generation. Stated another way, 82% came from better market interaction and 18% came from improved short-term shaping. Clearly the year 2001 value comparison indicates a large financial benefit if the software system had been in use by the planning and transaction departments. This brings up two key points:

Figure 5 Table of case Study Results	**Base Case**	**12 Month Analysis**	**Perfect Case**	**1 Fore-cast**
BLP generation (MW-hr)	1,673,036	1,809,779	1,589,541	1,776,575
OBP Generation (MW-hr)	716,232	749,975	755,714	754,612
HCP generation (MW-hr)	1,396,576	1,490,935	1,511,737	1,523,081
Total generation (MW-hr)	3,785,843	4,050,689	3,856,992	4,054,269
Modified Generation 2.88% decrease (MW-hr)	0	3,937,295	3,749,020	3,940,774
Additional Generation over Base Case	0	151,452	-36,823	154,931
Increase in generation over Base Case	0	4.00%	-0.97%	4.09%
% HL generation increase over Base case	0	7.11%	4.60%	8.04%

1. Year 2001 data-Meaning historic market conditions may not be applicable.
2. Use by planning and transaction departments- implies integration of the software into the planning and scheduling process will be successful.

Using a well-worn Wall Street qualifier, and modified for this discussion, " Past market conditions experienced during year 2001, most notably extremely high prices and the subsequent price decline, may not be a good basis for, or indicate future software returns". As stated previously, 82% of the gains displayed were the result of improved interaction with the energy market. Since future energy markets will not be similar to the 2001 market, much of these gains may not be available. In use by the planning and transaction departments, implies the software will be accepted and executed by these departments. Future acceptance and use by several different groups who previously acted autonomously is difficult to project, although the pilot project did identify several issues that if corrected, will facilitate software integration. As a footnote to the year 2001 case study, a similar case study is planned using year 2002 data, this case study should improve our understanding of the potential benefits in a more stable energy market.

Permanent System- Cost benefit

The decision to proceed with a permanent system was based not only on the financial analysis but also on additional benefits not addressed in the financial analysis. Listed below are areas where IPCo expects to utilize new optimization software:

- Spin reserve and load following– buy-sell volumes and timing
- Generation and voltage support capital investment decisions
- Future PM&E measures, most notably hydro project constraints
- Sensitivity analysis of forecasts to prioritize improvement efforts
- Monitor past performance of the planning and transaction process to facilitate improvement.

Along with the acknowledgement that additional benefits are possible there are also maintenance and upgrade costs, and initial hardware and license costs. In the end, our informal cost benefit analysis led us to purchase a permanent version of Synexus Global's VISTA optimization software.

Permanent System- Implementation and Integration

Implementation of a permanent system purchased during the summer of 2002 continues with the majority of work focusing on integration. Major changes from the pilot project prior to implementation include:

- All generation sources directly input as either modeled hydro, external sources, or contracts
- Load modeled as entire system load using both Short-term and long-term forecasts
- Complete transmission system modeled to include all market paths, generation sources, and loads including capacity constraints
- Long-term and short-term inflow forecasts with short-term automatically over-writing the long-term.

Integrating a new, complex software system into established work processes is difficult; the software must be easier to use or clearly provide better results than existing methods, and the input and output streams must blend with existing scheduling and planning procedures. Integration efforts have been concentrated to three areas; streamline input and output functions, training, and parallel-use testing. Examples for streamlining input and output; short-term and long-term inflow, price and load forecasts (six forecasts) are updated regularly but independently using various methods. This information must flow easily and/or automatically from the respective forecasters into the new software system, and this information must be easily verified and displayed by schedulers and planners. Output information such as generation schedules and future monthly heavy load and light load balances must be easily exported in familiar formats. In order to facilitate integration, several modifications were made. The computer driven short-term load forecast was posted on the optimization server automatically. Each short-term inflow forecast is pushed to the server via a simple spreadsheet executable. Price input was modified such that, day ahead, balance of month, and future months in heavy load and light load hours could be loaded from either the short-term or longer-term trading desks. To further increase price and unit status input efficiency, a future "Trader Window" will be developed. This window should decrease input errors but also increase use of the ST module because rapidly changing information will be easier to load. Parallel testing means the program will be operated in parallel with the current planning process to identify errors and omissions as well as to identify future improvements. And finally, but most importantly, training will be addressed not as an entry step, but as an on-going process. All of these integration methods require increased efforts from the utility, but it is critical the software be integrated to the fullest extent or the software will quickly loose effectiveness.

Conclusion

Idaho Power Company and Synexus Global conducted a pilot project to test the feasibility of a permanent hydro optimization software system. During the pilot project, a verification procedure was developed and a benchmark value was defined such that past operations could be evaluated with respect to historic forecast information. The pilot program was successful in that, financial benefits and system integration hurdles were identified. A permanent system was purchased after completion of the pilot project with testing and implementation continuing through the spring of 2003. Idaho Power Company has taken the first steps toward integration as a means to lower the over-all costs of meeting system load, but also as a means to improve the planning and scheduling process.

Authors

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