A Process for Prioritizing Upgrades and Life Extensions at PacifiCorp

With a core fleet of 22 hydroelectric projects ranging in age from 40 to 90 years, PacifiCorp faces potentially significant future capital expenditures for upgrades and life extensions. To prioritize expenditures and quantify potential costs of equipment failures, the utility used a risk-based planning process. Through this process, the utility identified equipment needing immediate work, as well as what can operate "as is."

By Mark A. Sturtevant, Darin E. Johnson, and Scott E. Anschell

PacifiCorp, a privately-owned electric utility in the western U.S., has a generation portfolio that includes 22 core hydro plants on five rivers, representing nearly 1,000 MW of capacity. These facilities range in age from 40 to 90 years. Recognizing the need for significant capital expenditures for upgrade and life extension work at these facilities, PacifiCorp's hydro generation group sought a method to quantify the cost arising from the risk of equipment failure. This method was needed to support the utility's economic analyses and to prioritize expenditures among these plants.

Mark Sturtevant, operations manager for PacifiCorp's hydro resources division, defined the scope of the consultants' work, supervised PacifiCorp's data collection efforts, and managed the prioritization project. Darin Johnson is director of asset management and Scott Anschell is a project manager at BIS Consulting. Mr. Johnson was the project lead for development of the overall prioritization process. Mr. Anschell provided risk modeling and other technical support.

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This article has been evaluated and edited in accordance with reviews conducted by two or more professionals who have relevant expertise. These peer reviewers judge manuscripts for technical accuracy, usefulness, and overall importance within the hydroelectric industry.

In 2003, PacifiCorp contracted with Acres International (now Hatch) to develop a long-range capital planning and prioritization model. BIS Consulting in Seattle is completing the prioritization model and providing ongoing support. Hatch is providing use of its HydroVantage risk analysis tool. As a result of this process, PacifiCorp refined its analysis of its 22 hydro facilities and chose the three needing the most immediate attention.

Understanding the process

PacifiCorp used a three-step approach to develop a project prioritization model:

— Collect data for each facility, including capital costs, outage costs, upgrade benefits, and operation and maintenance costs.

— Evaluate the condition of key components at each plant to determine which equipment is at the end of its economic life based on minimizing life-cycle cost, including capital cost, risk cost, and direct generation benefits. This evaluation used the HydroVantage tool.

— Develop and prioritize optimal upgrade and life extension programs around the equipment at end of life. This comprised quantification of the net benefits of the programs including avoided risk, and identification of the cost of delaying those programs, which is the basis for prioritization.

Key components at the plants are the high capital-cost items likely to drive an upgrade or life extension program, either because failure is extremely costly (e.g., stator winding) or because there is a significant benefit to upgrade (e.g., turbine runner). Components analyzed included turbine runner, stator winding, excitation system, governor, step-up transformer, generator breaker or high-voltage output breaker, and turbine inlet valve (if used as part of normal operation).

PacifiCorp is using the data collected and cost streams generated in its standard economic evaluation model. This allows the spending programs to be compared with other programs identified throughout the utility, such as life extensions at its coal-fired plants.

Collecting the data

Once PacifiCorp identified the process it would use to prioritize upgrades and life extensions, personnel set out to gather the necessary data. This included outage cost, age and condition, failure modes and effects, and intervention modes. Most data were collected in a week-long series of workshops involving engineering and maintenance personnel at PacifiCorp. The entire data collection task took about six months.

Outage cost

PacifiCorp calculated daily outage costs for each plant for planned and forced outages. These costs include lost generation and the value of reserves if applicable. Lost generation was estimated using as much as ten years of hourly historical generation to calculate the monthly megawatt-hours "at-risk" — the amount by which historical generation exceeds plant capacity with a unit unavailable. For plants with little or no daily storage capability, lost revenue is simply this at-risk generation multiplied by the expected price. Where there is storage, PacifiCorp typically shifts generation from peak to off-peak periods,

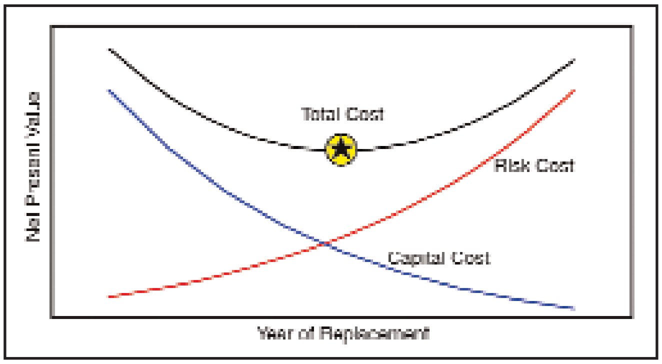

Figure 1: As equipment replacement is delayed, risk cost increases while capital cost decreases. The optimum timing to replace the equipment is at the lowest point on the total cost curve.

so lost revenue is estimated at the average monthly difference between peak and off-peak prices.

The daily cost of an unplanned outage, which can happen at any time, is the average cost over the entire year. PacifiCorp schedules planned outages to minimize lost revenue, so the utility assumed they would occur in the consecutive four-month span with the lowest expected lost revenue, based on the projected energy price and available water. (PacifiCorp chose a four-month duration because upgrade programs normally are driven by runner replacement or stator rewind, both of which entail an outage of this length.)

Age and condition

PacifiCorp captured the effect of equipment condition by adjusting the actual age relative to industry average. For example, if a 30-year-old circuit breaker has a condition much worse than is typical for this age, its effective age might instead be 40 years. The utility made these age adjustments in several cases where specific condition issues were identified by PacifiCorp's engineering or operations and maintenance personnel. The adjustments were subjective, based on the judgment of plant engineers with support from Hatch's engineering staff.

Failure modes and effects

For most components, the benefit of an upgrade or life extension program is avoided risk. To quantify this benefit, PacifiCorp defined the expected consequences of failure for each component. Because the goal was to develop a capital spending program, PacifiCorp focused on failures that lead to end-of-life. For each component, PacifiCorp estimated the effect of failure in terms of how long the unit would be down, direct repair cost, and the degree of destruction to the component as a result of the failure.

Single-winding stator failure is an example of a low degree of destruction. This probably would be repaired by simply jumpering the winding out, leaving the stator in essentially its pre-failure condition. On the other hand, a phase fault in the step-up transformer has a high degree of destruction that requires transformer replacement. For each component, PacifiCorp identified multiple failure modes, which were weighted to account for their contributions to the expected consequences of failure.

Table 1: Example Calculation of Net Present Value (NPV)

Year	*Component Age*	*Intervention Cost*[1]	*Risk Cost*	*Total Cost*[2]	*Present Value*
0	17	$0	$7,370	$7,370	$7,370
1	18	$0	$8,748	$8,748	$7,953
2	19	$0	$10,289	$10,289	$8,503
3	20	$0	$12,000	$12,000	$9,016
4	0	$100,000	$0	$100,000	$68,301
5	1	$0	$2	$2	$1
6	2	$0	$12	$12	$7
7	3	$0	$41	$41	$21
8	4	$0	$96	$96	$45
9	5	$0	$188	$188	$80
10	6	$0	$324	$324	$125
Net Present Value of Total Cost					$101,422

Notes:
[1]The cost for the intervention mode chosen for the particular piece of equipment.
[2]The net present value of all costs associated with a piece of equipment.

Intervention modes

Next, PacifiCorp determined its likely approach to mitigate risk for each component. In most cases, the intervention was an in-kind replacement. However, several interventions were upgrades, such as replacing mechanical or electronic analog governors with digital ones, or installing higher-efficiency runners. PacifiCorp also considered the option of purchasing spares, especially for transformers where a single spare can mitigate the risk from several units.

For each intervention mode, PacifiCorp identified the expected direct cost and outage duration, the rejuvenation (i.e., whether it returns the component to like-new condition or subtracts years from its effective age), and any direct benefit from increased efficiency or capacity.

Running the calculations

The next step was to calculate the optimal intervention timing for each piece of equipment, based on its age and condition, the consequences of failure, and the costs and benefits of replacement or rehabilitation. This step was performed using HydroVantage.

HydroVantage is a risk-based tool used to perform economic optimization of replacement, rehabilitation, or other interventions for aging power system equipment. The tool balances the cost from the risk of failure against the benefit of delaying capital expenditures to determine the optimal timing for intervention. This calculation uses risk cost to quantify the cost of operating aging equipment, where the annual risk cost is the product of the probability of failure in that year and the consequence cost of that failure.

Risk cost increases as equipment ages and its failure probability increases. HydroVantage includes a database of failure probability curves for common equipment, based on historical data and industry surveys. These curves define the annual probability of failure as a function of the component's age. Curves of this type are referred to as "bathtub curves."

HydroVantage calculates the present value of all expected costs (capital, operations and maintenance, risk, and generation benefit) associated with each intervention timing, from immediate to do-nothing. The timing with the lowest net present value (NPV) of costs is the least-cost strategy, and intervention should be planned for that time. Figure 1 shows the tradeoff between capital and risk cost as intervention timing is delayed. The total cost curve represents the NPV of all costs associated with a piece of equipment. If the component is replaced too late, total cost is high because of high risk cost. If replaced too early, total cost also is high because the present value of the capital cost is high.

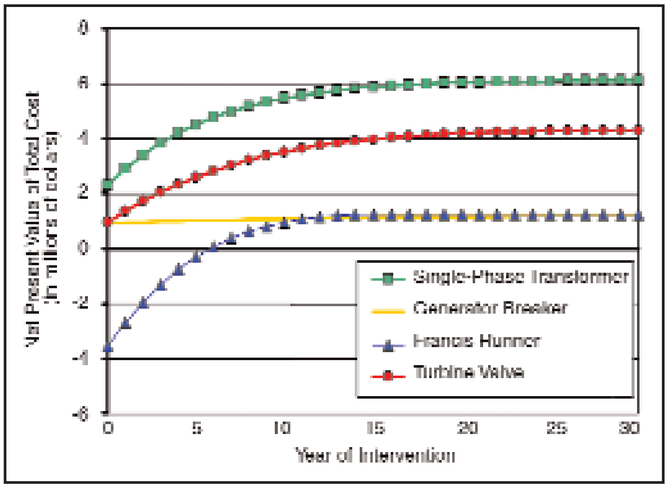

Figure 2: Curves illustrating the net present value of replacing several pieces of equipment show that the optimal intervention timing is year 0. As time passes, cost to implement the programs increases.

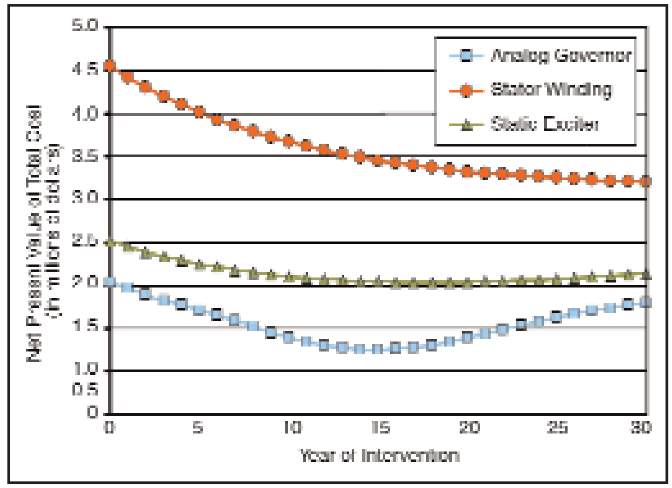

Figure 3: By comparison, the net present value of replacing several other pieces of equipment at the same plant is high in year 0, indicating this is not the optimal timing to replace these components.

A real-life example

Consider an analysis of the 94-year-old generator breaker on the low side of the step-up transformer at one plant. The daily costs for planned and forced outages reflect expected lost revenue if the breaker fails, taking the unit off-line. The intervention mode is replacement. Capital cost for replacement includes $50,000 for the breaker and $100,000 for the enclosure, relays, and other appurtenances. The expected outage is 30 days, which is multiplied by the daily cost of a planned outage ($4,594) to give a total outage cost of $137,815.

Two failure modes were modeled for this component. The minor mode, FM 1, is a non-destructive low consequence cost and outage duration. When a breaker fails in this way, it is out of service for repairs for about 30 days. Destruction of 10 percent means the breaker is 10 percent destroyed by this failure. Participation of 95 percent means 95 percent of breaker failures are expected to be of this mode.

The major mode, FM 2, is a fully destructive event, such as failure to open in a fault. This is more costly and causes a longer outage than FM 1 but is less common — participation is only 5 percent. Destruction of 100 percent means the breaker is totally destroyed, so direct cost and other damage sum to $150,000, representing the same cost as the breaker replacement. The outage duration following a major failure is 120 days, which includes the time for delivery and installation of the replacement breaker.

Calculating total NPV

Table 1 on page 33 shows a calculation of total NPV for replacement of a 17-year-old component. The example includes intervention and risk costs, but no direct benefit, so it might apply to a component other than a turbine runner. We used a ten-year analysis and a discount rate of 10 percent. The discount rate, which reflects the opportunity cost of any expenditure, is used in calculating the present value of future costs in economic analyses.

The intervention cost, which includes both capital and outage costs, shows the replacement in year 4. The risk cost starts out high while the old component is still in service, but drops after replacement. The total cost in each year is the sum of these two costs, and the NPV of the total cost, $101,420, is the cost associated with replacement in year 4. This can be thought of as the amount of money you would have to set aside today at 10 percent interest to finance this component throughout its life.

To optimize the replacement timing, the total NPV of this strategy would be compared with the total NPV of other strategies (i.e., replacement in year 0, year 1, etc., or do-nothing) to find the lowest-cost strategy.

Equipment that has reached the end of its economic life has a minimum total NPV in year 0, indicating that the optimal timing is now. This equipment will tend to be old, in poor condition, or highly critical so that failure is very costly. The near-term upgrade and life extension programs for PacifiCorp's hydro plants comprise the components whose optimal intervention timings are in year 0. Future spending needs can be estimated based on the times at which other equipment will reach the end of its economic life.

Program development and prioritization

Figure 2 shows the HydroVantage output curves for the step-up transformer, generator breaker, Francis runner, and turbine inlet valve at Plant A. The minimum total cost for all four components is in year 0, meaning all would be included in an upgrade program. Because these components have reached end-of-life, the minimum points of the U-shaped curves are at the far left.

Note that the NPV for the runner upgrade is negative for intervention in years 0 through 5. NPV is negative because the proposed runner upgrade includes an efficiency increase, which will produce direct revenue benefit and this benefit is counted as a negative cost.

PacifiCorp also analyzed the governor, stator winding, and static exciter at Plant A. (See Figure 3.) None of these components was found to be at end-of-life, as the NPV of total costs for each component is minimized if they are replaced many years in the future.

PacifiCorp designed the upgrade programs at each plant to take advantage of concurrent outages that would allow costs to be minimized. For example, some components whose optimal timings are in the future are included in the program because the unit is being taken out of service to replace or upgrade another component. Replacing both at the same time avoids an extra outage.

The sum of the four curves in Figure 2 represents how total cost for the plant increases as the upgrade program is delayed. Figure 4 shows this sum for three plants. These NPV curves give an indication of the priority of each plant's

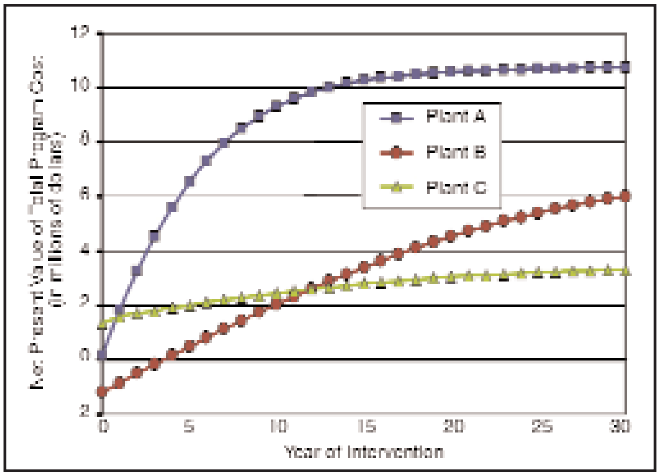

Figure 4: Net present value curves generated for three PacifiCorp plants show that, while optimal intervention timing for all three plants is year 0, costs increase much more rapidly for Plant A than for Plant C if intervention is delayed.

upgrade program relative to other plants. The cost curve for Plant A increases quickly as intervention is delayed, whereas the curve for Plant C increases slowly. This means that although the optimal upgrade timing for both plants is immediate, costs increase faster if Plant A is delayed than if Plant C is delayed. Therefore, Plant A is the higher priority.

To consistently quantify the cost of delay, PacifiCorp compared the NPV of all costs associated with a year 0 program to a program three years later. This comparison gives an idea of the steepness of the cost curves (i.e., the rate at which costs increase as the program is delayed). The three-year delay is a compromise between too short an interval, which may overestimate PacifiCorp's ability to plan and execute several large-scale upgrade programs consecutively, and too long an interval, which may hide some short-term effects of delay (e.g., very steep curves that flatten out later). The cost of delaying the upgrade programs ranged from about $50,000 to nearly $6 million. Plant A is one of the highest-priority plants in PacifiCorp's system, while Plants B and C are much lower. Several plants had no near-term upgrade program, meaning that none of their equipment has reached end-of-life.

Results for PacifiCorp

The results of this process are that PacifiCorp has identified optimized upgrade programs for each of its core hydro facilities. It has prioritized those programs and established defensible support based on a quantitative economic analysis and empirical failure probability data.

To justify the needed spending, PacifiCorp uses a standardized economic decision model. This model computes the NPV, benefit-cost ratio, and other relevant measures for a proposed spending program using standardized methods and assumptions, which ensures that all proposed spending is compared on consistent terms. The inputs and outputs of this upgrade prioritization analysis are entered directly into PacifiCorp's economic model. Key entries to the model include:

— Capital cost and outage duration for the upgrade program, developed during data collection.

— Estimated generation benefits from upgrading turbine runners. This process included a method of estimating the revenue benefits of runner upgrade, including improved efficiency and reserve benefits.

— Benefit of the upgrade in terms of avoided risk cost, including both the repair risk for failed equipment and lost generation and spinning reserves from a forced outage. Equipment risk and outage risk were entered into the economic model as separate, 30-year streams.

The highest-priority programs were submitted and reviewed in this way, and PacifiCorp has approved and begun planning these upgrade programs. In fact, the highest priority projects are currently in the design and procurement phases. The process has been used to prioritize and budget plant overhauls and component replacements for the next 15 years. The process described here has benefited PacifiCorp in three ways:

— It provides an economic basis for prioritizing expenditures. Because the benefits of avoided risk are quantified rigorously, PacifiCorp has a clear picture of how the costs and benefits of any upgrade program change based on scheduling.

— It produced quantitative, independent, and empirical justification for the upgrade and life extension programs at core hydro facilities. The HydroVantage tool includes failure data from a broad sampling of industry sources, which increases PacifiCorp's confidence in the results.

— It helped to define the scope of the upgrade and life extension program at each facility by identifying which components had reached end-of-life. Also, by comparing the total costs of competing strategies (replacing step-up transformers versus purchasing spares, for example), PacifiCorp was able to further refine the programs. ■

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