

A Probabilistic Process to Balance Reliability and Cost for a Station Design

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Abstract—This paper presents a probabilistic process for selecting a station design by balancing cost and reliability. Four station designs were evaluated using reliability indexes and economic analysis to come up with the most cost effective and reliable design overall. For each design option, we performed an economic analysis using Net Present Value (NPV) of total costs (capital, O&M, and outage). We then used the analysis results to rank the options. A number of sensitivity studies on the NPV of total cost were conducted to examine the effect of varying major parameters on the ranked options. The process was applied to a real case study performed for one of the Idaho Power Company (IPC) substations.

Index Terms—Outage cost, Probabilistic methods, Reliability, Substation design.

I. INTRODUCTION

In new substations or existing station modifications, design engineers attempt to determine the right balance between cost and reliability. A station design team strives to find a design that meets various requirements, such as cost, reliability, ease of maintenance and future expansion, as well as company and regulatory agency guidelines. The process of selecting a final design can take several iterations because each participant provides his or her input based on experience. This process seems to work well and, generally, the design team selects the “best” option. However, this is a subjective process. It is always possible that the design selected may not be the most cost effective. Our goal was to develop a more objective and defensible process. First, we quantified station reliability after examining an exhaustive set of outages that may cause performance degradation. Then, we quantified the total cost of each option to select the best option. The process helped us in selecting an option using cost and the intrinsic station design based on historical performance of station components. The following are the major steps in the process:

1. Identify credible options.
2. Calculate the probabilistic reliability indexes of each option, including expected unserved energy.
3. Calculate the outage cost of each option.
4. Calculate the Net Present Value (NPV) of the total cost of each option.
5. Rank the options.

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6. Perform sensitivity analysis to verify the robustness of the options ranking.

7. Select the option with the lowest NPV if the sensitivity analysis in step 5 confirms it. If the ranking order in step 5 is not sturdy enough, more studies need to be done.

This process requires customer outage costs data to implement. We recommend using a computer program to examine several hundred outages caused by the failure of station components.

Most of the published work [1]–[11] describes the first two steps in prioritizing a station design. Much work has been done to estimate customer outage costs and its use in ranking projects [12]–[17]. This paper describes Idaho Power Company’s (IPC) experience applying this probabilistic method in selecting a station design. We focused on validating the selected design by conducting a number of sensitivity studies to help us develop a defensible process for ranking station designs.

II. PROCESS DESCRIPTION

A. Reliability Analysis

The analysis was done using a computer program, SUBREL, which calculates reliability indexes for an electric utility substation and generating station switchyard [18]. The program models the outages caused by failures of both station components and of terminated lines and generating units. It models all required automatic and manual switching operations after a component outage. It also simulates maintenance overlapping forced outages and stuck breaker/fuse outages (failure to open when needed to clear the fault).

For each outage, the program takes time-sequenced switching actions (automatic and manual), including load curtailment or load transfer (or load rolling), which are required to avoid overloads and maintain flow balance.

The program computes a set of reliability indexes that are divided into four categories:

1. Contingency summary
2. Outage frequency and duration of terminating components (referred to as load points) for each outage event
3. Load points (terminated lines/transformers) reliability indexes
4. Total substation or system reliability indexes

The contingency summary gives the total number of primary and secondary outages that were examined by the

program. It also provides contingencies that result in a total or partial loss of substation load. Individual load point indexes, such as outage cost and energy interruption, are used to compare the reliability performance of each load point.

Table I shows the reliability indexes computed by the program:

- Frequency of Interruption (per year)
- Outage Duration (minutes per outage)
- Expected Unsupplied Energy (EUE) (kWh per year)
- Expected Outage Cost (EOC) (thousand \$ per year)
- Availability

The following is a list of outage events included in the analysis:

1. N-1 and N-2 forced outages of a substation component:
 - Breaker
 - Transformer
 - Bus Section
 - Switch
2. N-1 and N-2 forced outage of an incoming line.
3. Forced outage overlapping a maintenance outage for substation equipment or an incoming line.
4. Stuck breaker/fuse (failure to open when needed to clear the fault).
5. Time-sequenced switching actions (automatic and manual) including load curtailment or load transfer (or load rolling) required to avoid overload of transformer, or under specified Remedial Action Scheme (RAS).

For each outage contingency, probability, frequency and duration indices are calculated using Markov Models [2,3,5].

B. Economic Analysis

To provide a fair return to its shareholders, a utility company must operate as a business. Thus, it is important that utility investments be based on the results of an economic analysis. The major steps required in an economic analysis are well documented in various publications [17]. They involve computing the NPV of the total cost (capital, O&M, and outage) for each option. The NPV is then used to rank various options. It is quite easy to calculate both the capital cost (construction cost) and the O&M cost. Customer outage costs can be estimated based on direct and indirect costs to a customer. However, the process of quantifying the outage cost is more involved and requires surveying customers. Also, public utility commissions are looking into playing an active role by both penalizing and providing incentives to a utility based on service performance. Recently, the California Public Utility Commission (PUC) has suggested a Performance-Based Rate (PBR) mechanism in project evaluation to ensure service reliability [13].

As a progressive utility, we are proactively taking steps to include outage costs in our selection process. We believe that, even before PBR mechanisms are in place, utilities will include customer outage costs in their decision-making process. At IPC we strongly believe that by including outage costs in our design and planning process, we can better meet our customers' needs, regardless of whether or not a PBR

mechanism is in place. The question is what costs should be included as outage costs in the analysis. Outage costs due to supply interruptions are much greater for customers than for utilities. For a utility like IPC, the loss of revenue is only a few cents per kWh. Revenue losses for customers, on the other hand, have been estimated to be anywhere between \$1 per kWh to \$40 per kWh based on customer surveys [14]–[16]. The variation in the customer outage cost is due primarily to the customer type. In the analysis, it is best to use the outage cost that is specific to the customers who get their electricity from the station under consideration. However, if this information is not available, outage cost data gathered through general customer-type surveys can be used after taking into account the composition of customers (both present and future) served by the particular station.

III. CASE STUDY: ONTARIO STATION OPTIONS

The case study involved a bus reconfiguration of the 230/138 kV Ontario substation. The need for this design came about after IPC studied the feasibility of improving the Idaho/Northwest transfer capability in both directions. At certain times, under high water conditions, the hydro system in the Brownlee/Hells Canyon area can restrict the Northwest to Idaho imports. These restrictions are due to steady state thermal conductor limits. To alleviate the restrictions, two internal paths upgrade of Brownlee North and Brownlee East were investigated. The following transmission projects for increasing Brownlee East's capacity were considered (Fig. 1):

1. Add a new 230 kV line between Brownlee and Ontario
2. Add series capacitor at the Ontario 230 kV terminal of this new line (Ontario-Brownlee)
3. Convert the Ontario-Caldwell 138 kV line to a 230 kV line
4. Add a second transformer at Ontario

Implementing these transmission projects into the Idaho system required a comprehensive study of several options for the 230/138 kV Ontario station. IPC's station design team proposed several options, but a detailed study was performed only for the four most promising station options. These options and the results of the studies are described below.

A. Description of the Options

All four station options incorporate system changes required by the Brownlee East capacity increase and have the same base system structure: two supply sources at the 230 kV side, two transformers that connect these two sources to the 138 kV side, and three transformers that connect the 138 kV side to the 69 kV side of the station. The load side for all the station options is the same: it comprises two 138/13.8 kV transformers, two 138 kV lines, and four 69 kV lines that connect the station to the load centers. The four station design options are identified as A, B, C, and D. Option A represents the existing station configuration with system changes (Fig. 2). This option has deficiencies at both 230 kV and 138 kV bus configurations. It is considered only for comparison purposes.

Brownlee-Ontario Transmission Project

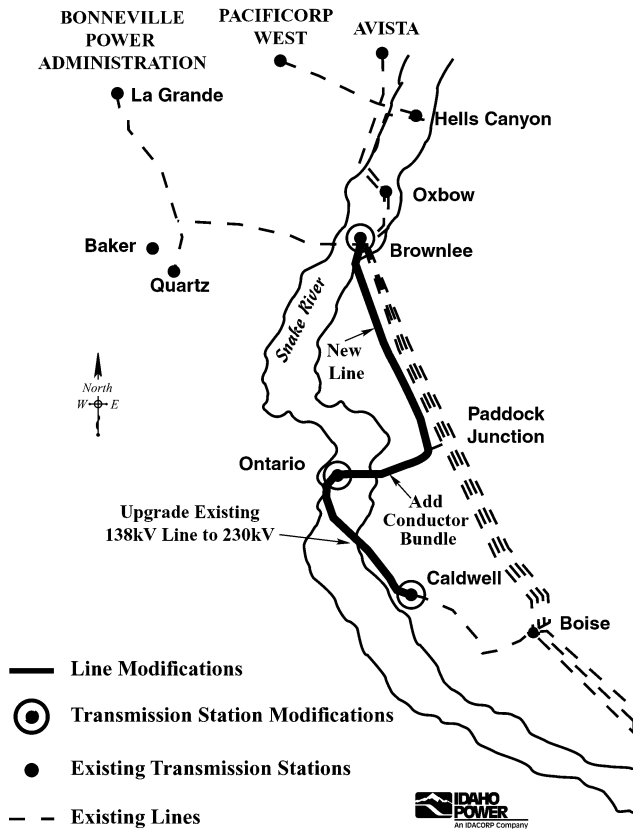


Fig. 1. Brownlee-East Capacity Upgrade Projects

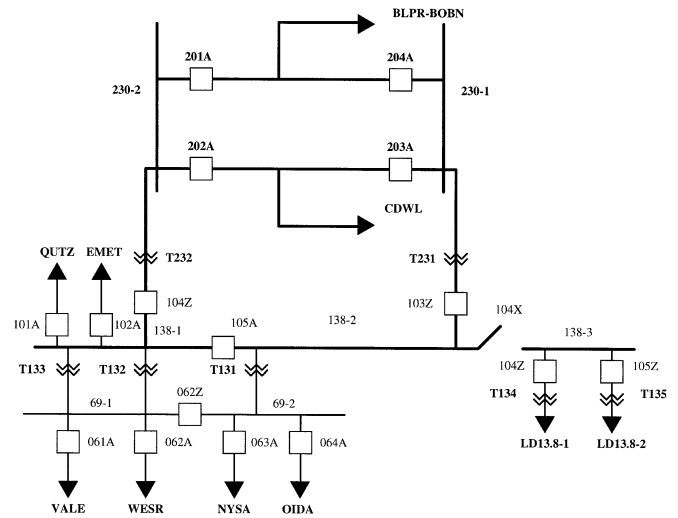


Fig. 3. Ontario Station - Option B.

Option C (Fig. 4) includes modifications on the 230, 138, and 69 kV switchyards. The 230 kV and 138 kV switchyards have a ring bus arrangement, making them more reliable and flexible. Again these changes help in facilitating maintenance on the 230kV and 138kV breakers. In addition the 69 kV has an operations and maintenance bus arrangement.

Option D (Fig. 5) is similar to option C. The only difference is that the transformer T135 has been moved to the bus 138-1. This arrangement was proposed by operations personnel to avoid simultaneous losses of transformers T135 and T131.

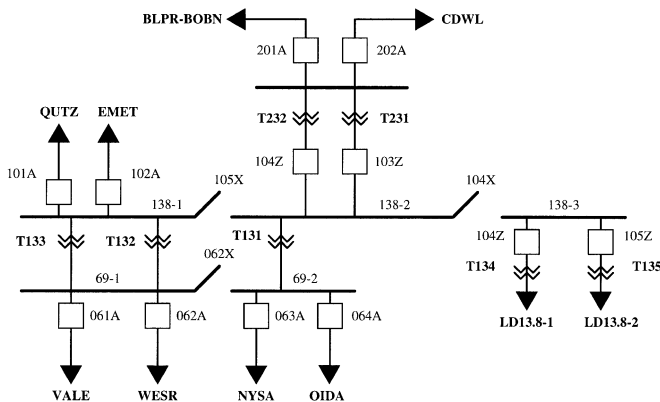


Fig. 2. Ontario Station - Option A.

Option B (Fig. 3) includes a ring bus arrangement for the 230 kV side, making it more reliable and flexible and thus facilitating maintenance on the 230kV breakers.

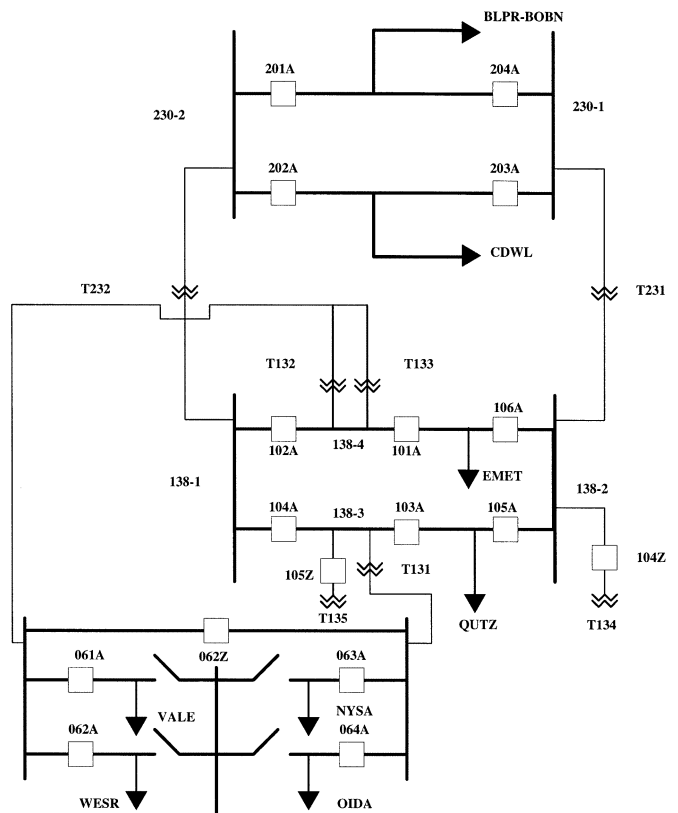


Fig. 4. Ontario Station - Option C.

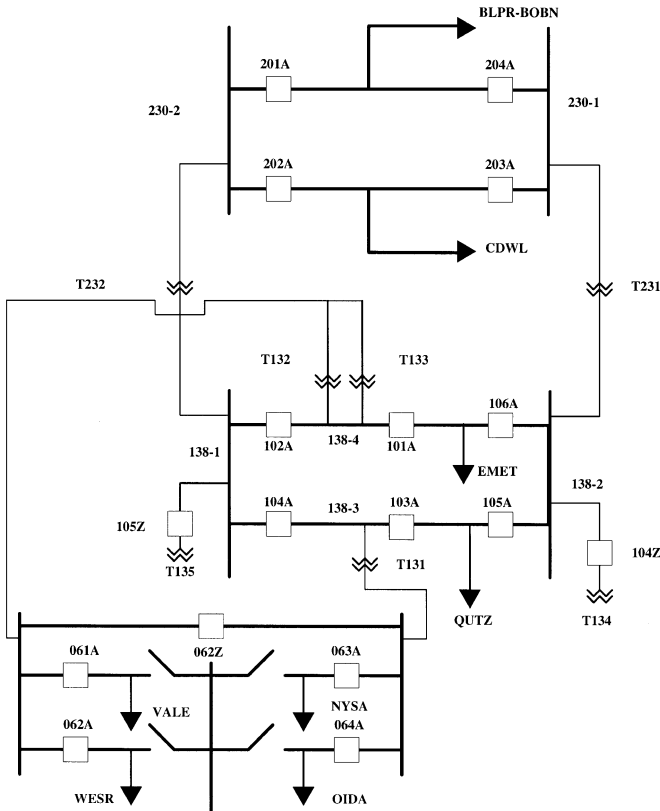


Fig. 5. Ontario Station - Option D.

B. Results

In Table I, note that the EUE for options A and B is higher than for options C and D. With the proposed modifications in options C and D, both the frequency and the duration of supply interruptions to customers have decreased. A number of sensitivity studies were performed by changing outage statistics for various critical components. These studies confirm that options C and D have better reliability than options A and B. All costs in Tables I–V are given in thousands.

Table I also shows the construction cost of each option. We can assume that the O&M costs are almost equal for each option. Therefore, they are not included in the analysis. In order to calculate the present value of the total project cost for each option, we made assumptions for the following four parameters:

- Station life in years.
- Number of years, from today, before the cost of the unserved energy is regulated by a PUC or similar agency. Before this happens, the cost of the unserved energy is the loss of revenue cost.
- Cost of the unserved energy (\$/kWh) after it is regulated.
- Cost of Capital (WACC).

In our analysis, we used the following values:

- cost of capital = 8.5%
- station life = 50 years

- cost of unserved energy (outage costs) = \$5 per kWh
- loss of revenue cost = \$0.06
- number of years before PUC may regulate outage costs = 10 years

Table I gives the NPV of each option's total cost. Option C was selected because it has the lowest NPV cost.

TABLE I
OVERALL SYSTEM INDEXES AND TOTAL COST

Index	Options			
	A	B	C	D
Capital Cost	\$3,500	\$4,500	\$5,020	\$5,320
Frequency of Interruption	0.365	0.300	0.222	0.220
Outage Duration	8.78	5.99	3.24	3.23
Availability	0.99932730	0.999332	0.99966901	0.9996712
EUE	454400	305000	193000	184000
EOC/ year	\$2,272	\$1,525	\$965	\$920
NPV of the Total EOC	\$11,519	\$7,732	\$4,892	\$4,664
NPV of the Total Cost	\$15,019	\$12,232	\$9,912	\$9,984

If revenue loss is the only selection criterion, then option A is the best option, as it requires the least capital expenditures. On the other hand, if reliability is the only deciding factor, or if the outage cost is \$7/kWh, then option D is the best option, as it offers the best reliability among all the options. However, if both capital expenses and the resulting savings in station reliability are included, then option C is the best option, as it has the lowest NPV of the total costs. As pointed out earlier, sensitivity analysis should also be done to verify the robustness of the ranking process. Tables II–V show the results of the sensitivity analysis for the four parameters. We have also highlighted the option that has the lowest NPV, as a parameter value is varied.

In Table II, we can see that options C and D are the preferred options. If the new rate is implemented immediately, option D is the best option. If the new rate is implemented after six years, then option C is the best design.

TABLE II
NPV OF THE TOTAL COST VERSUS REGULATED YEAR

Year	Options			
	A	B	C	D
1	\$27,704	\$20,746	\$15,300	\$15,121
6	\$19,535	\$15,263	\$11,831	\$11,813
7	\$18,264	\$14,410	\$11,291	\$11,298
10	\$15,019	\$12,232	\$9,912	\$9,984
15	\$11,098	\$9,600	\$8,247	\$8,397

In Table III, one can conclude that the life of the substation has no effect in selecting the best option. Option C remains the best option for all values of station life.

TABLE III

NPV OF THE TOTAL COST VERSUS STATION LIFE

Station Life	Options			
	A	B	C	D
20	\$10,242	\$9,026	\$7,884	\$8,050
35	\$13,933	\$11,503	\$9,451	\$9,545
50	\$15,019	\$12,232	\$9,912	\$9,984
65	\$15,338	\$12,446	\$10,048	\$10,114
80	\$15,432	\$12,509	\$10,088	\$10,152

In Table IV, we can see that if the cost of EUE is \$1 or less, option A is the best option. If the cost of EUE is \$6.5 or less, but higher than \$1, then option C is the best alternative. If the EUE cost is \$7 or greater, then option D is the best alternative.

In Table V, we can see that option D is the best option if the cost of capital is 7% or less. Otherwise, option C offers the best design.

TABLE IV
NPV OF THE TOTAL COST VERSUS OUTAGE COST

Outage Cost	Options			
	A	B	C	D
\$1.0	\$5,923	\$6,126	\$6,049	\$6,301
\$1.5	\$7,060	\$6,890	\$6,532	\$6,762
\$5.0	\$15,019	\$12,232	\$9,912	\$9,984
\$6.5	\$18,430	\$14,521	\$11,361	\$11,365
\$7.0	\$19,567	\$15,284	\$11,844	\$11,826

TABLE V
NPV OF THE TOTAL COST VERSUS WACC

Capital Cost	Options			
	A	B	C	D
6.5%	\$20,784	\$16,102	\$12,361	\$12,319
7.0%	\$19,057	\$14,942	\$11,628	\$11,620
7.5%	\$17,540	\$13,924	\$10,983	\$11,005
8.5%	\$15,019	\$12,232	\$9,912	\$9,984
13.5%	\$8,335	\$7,745	\$7,073	\$7,278

The sensitivity analysis is very useful in studying the impact of various parameters in selecting a robust station design. Option D is sometimes the best option. However, for the design values and for most of the parameter ranges, option C is most often the best option.

IV. CONCLUSIONS

We have proposed a probabilistic process for balancing reliability and cost when selecting a station design. In our process, we retained the basic steps of traditional probabilistic methodologies. We did, however, extend the process to include sensitivity analysis to determine the impact of varying major parameters on the ranked station design options on the

NPV of total cost. We have shown that the NPV of total cost, together with sensitivity studies, can be used to identify the most cost-effective design. The NPV of total cost provides a consistent measure for ranking various substation design options.

Furthermore, because our process can be applied not only to stations but to any part of the system to balance reliability and cost, it can be a useful and versatile planning and design tool. By applying the probabilistic process to the Ontario substation, IPC was forced to gather all the necessary data, including customer outage costs, needed to perform the economic analysis. The knowledge gained from this case study will help us in planning and designing our facilities so that we can be prepared to meet any performance-based standards the PUC may decide to adopt. We believe that further applications of the process should give us enough confidence in applying it to develop better investment strategies.

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