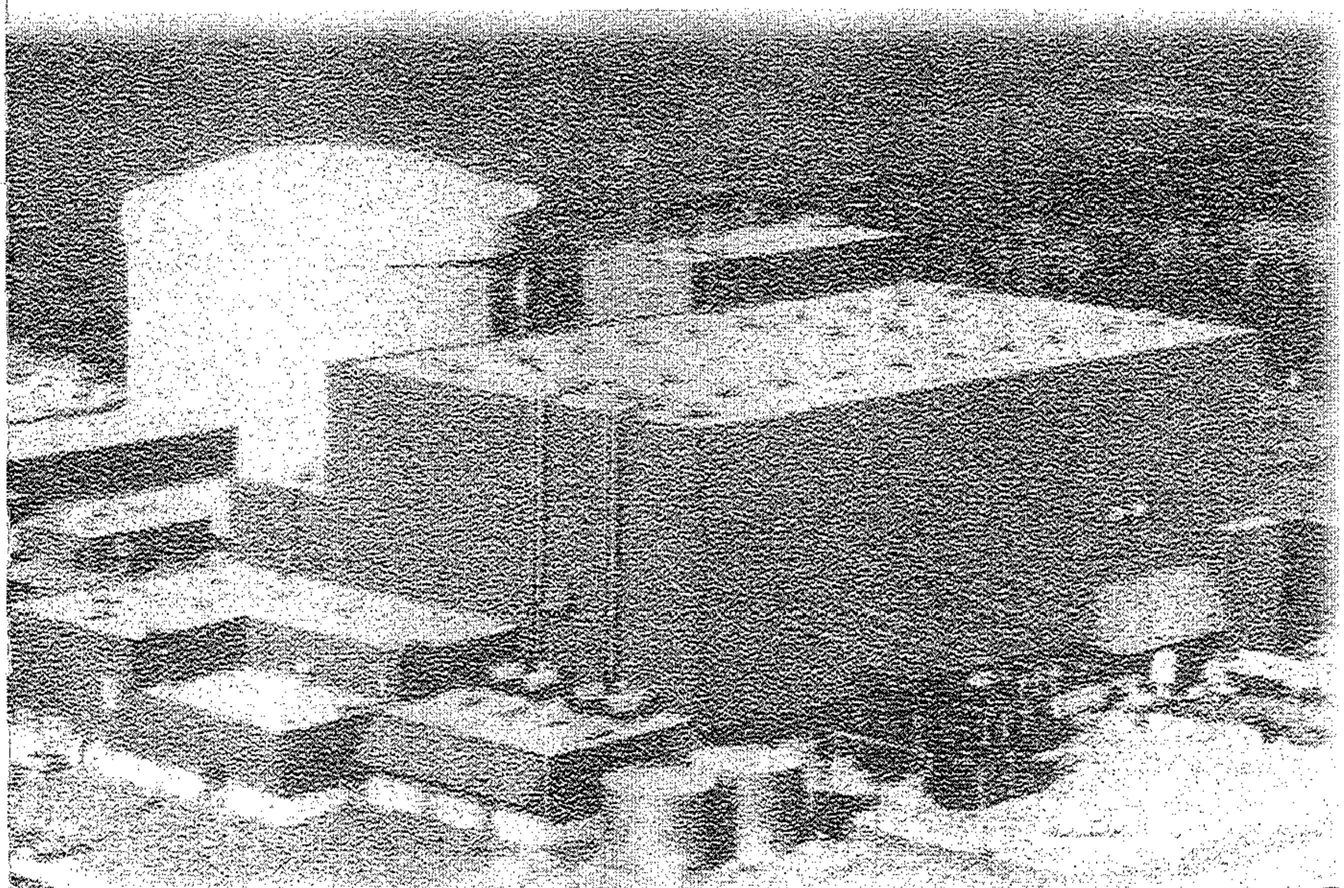

GENTILLY 2

STRATEGIC ASSESSMENT

Summary Report
Final
September 9, 1998

Hagler Bailly

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Prepared for Hydro Quebec

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Executive Summary

S.1 Overview

Hydro Québec owns and operates the Gentilly 2 Nuclear Station, a 635 net output MW_e CANDU (Canadian Deuterium Uranium) reactor that has been in operation since 1983. The CANDU units have a unique design that allows for operation during refueling.

The reactor consists of 380 separate fuel channels. These fuel channels consist of a pressure tube, which contains fuel bundles, and an inlet and outlet feeder pipe that allows for coolant to flow around the fuel and transfer heat to the steam generators. Each pressure tube is located inside a calandria tube, which separates it from the cold moderator heavy water. The fuel channels are designed to be replaced either singly or in groups. Current design life for Gentilly 2's fuel channels is 30 years at an 80 percent capacity factor or 210,000 equivalent full power hours (EFPH). Much of the equipment in the station can be operated for greater than 30 years and consideration is being given to replacing the fuel channels to allow for operation of the station past the 30-year design life.

Strategies for replacing the fuel channels and for continued operation of Gentilly 2 are being explored. The strategic plan for operating Gentilly 2 should match the overall goals of Hydro Québec. Gentilly 2 represents only 3 percent of the overall generation of Hydro Québec; however, it is an important source of energy during times when replacement power, typically hydro, is not as fully available. Gentilly 2 is not subject to hydraulicity experienced by hydroelectric stations and provides a stable source of capacity and energy. Also, the location of Gentilly 2 provides voltage stabilization for the grid.[1] Thus, longer annual outages may be acceptable alternatives to an outage that keeps the station from operating for a year or longer.

Hydro Québec requested Hagler Bailly Consulting, Inc. (Hagler Bailly) to evaluate the long-term strategic planning of Gentilly 2. Hagler Bailly is an international consulting firm with staff specializing in both nuclear engineering and economics. We have conducted numerous valuation studies of generating assets for international utilities and other clients. We have assessed the operation of nuclear power plants and recommended strategies to utilities on continued operation. We are one of the leading consulting firms in strategic assessment for utilities and private corporations. The combination of these skills enables us to independently assess the operational strategies of Gentilly 2. Hagler Bailly developed a model that considers three different operating strategies.

1. Memo from Yves Filion, Vice President, Production, Transportation and Telecommunications, Hydro Québec, 7/22/94.

S.2 STRATEGY 1 — MODULAR REPLACEMENT OF FUEL CHANNELS

In Strategy 1, the plant will be operated, maintained, and refurbished by conducting short, modular maintenance outages. In this strategy, a quarter of the pressure tubes and feeder pipes are replaced each year from 2005 to 2008. These dates were chosen because it is expected that at least some of the pressure tubes will need to be replaced by 2008.

S.2.1 Timing of Fuel Channel Replacement

There are several determining factors in addition to the design life of the pressure tubes that may limit the plant's life before the 210,000 EFPH. One of the most critical issues currently being addressed is the deuterium pickup in the pressure tubes, which makes the pressure tubes more susceptible to failure by delayed hydride cracking (DHC). Atomic Energy of Canada, Limited (AECL) has recently developed a new "Design Equation" to predict the deuterium concentration in the pressure tubes as a function of time in service.[2] The rate at which the concentration increases was previously assumed to be constant (linear increase with time), whereas the new Design Equation has the rate increasing more quickly with time. If the new Design Equation is valid, the limiting deuterium concentration, the Terminal Solid Solubility (TSS) Threshold, of the Fitness-For-Service Guidelines[3] could be reached in late 2008. Measurement of the scrapings done in 1998 at Gentilly 2 have shown indications that the Design Equation may be valid. As of June 1998, inspection techniques and results are being reviewed.

Thus, the most conservative analysis ensures that all of the pressure tubes are replaced by 2008. After refurbishment, the station operates until 2033. This is based on the plant life extension program[4] developed by AECL, which suggests a 25-year life extension period.

S.2.2 Feasibility Issues

If this strategy is considered a suitable option, several feasibility issues of replacing a quarter of the reactor core at a time must be addressed in detail.

There are several issues that have not yet been addressed by the CANDU industry if the fuel channels are replaced on a modular basis. These include the ability to replace the calandria tubes,

2. Bahurmuz, A.A. et al., "A Design Equation for Predicting Corrosion and Deuterium Ingress in Pressure Tubes (Rev. 1.0)," AECL RC-1551, COG-95-596, September 1996.

3. AECL Memo, A.A. Bahurmuz and V.F. Urbanic to W.R. Clendening, "Deuterium Pickup in Bruce and CANDU 6 Pressure Tubes," RMR-97-239, 7/11/97.

4. "CANDU Plant Life Management and Plant Life Extension," B.A. Shalaby and E.G. Price, AECL, Mississauga, Ontario, Canada, 1997.

positioning and clearances of the pressure tubes and feeder pipes, fueling machine interferences, isolation and draining of the pressure tubes being replaced, reactor physics considerations, and radiation fields. These issues will not be resolved in the near term; however, if this operational strategy is chosen, research and development must be done to resolve these feasibility issues.

For this strategy to be feasible, each of the four annual outages should be less than eight months each year. If this option is chosen, improvements to the work processes to shorten the expected outage time must be made to meet Hydro Québec's goals.

S.3 STRATEGY 2 — ONE-TIME REFURBISHMENT OF FUEL CHANNELS

Strategy 2 calls for continued operation until major refurbishment of the plant is required. This strategy operates Gentilly 2 until 2008 and then the fuel channels are replaced during a single refurbishment outage. As with Strategy 1, after the refurbishment outage the plant will continue to operate until 2033 before permanent shutdown.

S.4 STRATEGY 3 — NEW CANDU 6 STATION

Strategy 3 calls for the construction of a replacement CANDU 6 nuclear station at the end of Gentilly 2's design life or when a major pressure tube/feeder pipe replacement is required. The costs for Gentilly 2 were calculated until 2008 when it was assumed to be decommissioned. Then a cost for substitute power was developed. We will call this Gentilly 3. AECL provided a preliminary estimate of the overnight costs (costs not including financing and interest) of a new CANDU 6 reactor. To address the financing and interest costs, we estimated the finance charges during construction of the project as well as financing and interest charges for the 40-year life of the new station. We also include additional costs for licensing, commissioning, decommissioning, and spent fuel storage costs for the new reactor. Annual routine outage costs, operations, maintenance, and administrative (OM&A), fuel, and capital costs are assumed to be the same as Gentilly 2 and to continue for a new Gentilly 3 unit. From these costs we develop an $81.21 cost per MWh. This cost is then applied in the model for 25 years (2008 to 2033) at 80 percent to replace Gentilly 2 generation.

The costs do not include wholesale replacement of the pressure tubes or feeder pipes. If this strategy is considered a viable option, Hydro Québec should negotiate a guarantee that the pressure tubes in the new station last for at least 40 years at an 80 percent capacity factor.

S.5 EVALUATION OF ALL COSTS INCURRED

For each strategy identified above, we estimated the costs incurred using probability distributions for the minimum, most likely, and maximum possible costs. In addition to addressing the costs of replacing the fuel channels, we also evaluated equipment, regulatory, and routine cost issues. For each equipment issue we estimated the probability of occurrence, outage time, and costs associated with equipment failures or equipment replacements. Additional regulatory costs were evaluated if there was a possible increase in capital, OM&A costs, or outage time. Routine costs and outages include routine annual OM&A costs, routine annual capital expenditures, annual planned outages, other scheduled and forced outages, fuel costs, intermediate and low level waste (LLW) disposal and storage costs, irradiated fuel management (IFM) costs, and decommissioning costs.

The model is designed to compare the economic feasibility of Gentilly 2 for the three operating strategies. For each strategy, the model computes the total going-forward cost of 635 MW_e of power — the net capacity of Gentilly 2 — for every hour during a fixed time horizon, beginning with 1999 and running through 2033. For Strategy 3, we developed a cost/MWh for the new station and treated this cost as substitute power from 2008 to 2033.

Future costs are discounted to account for the time value of money. All costs are in 1998 Canadian dollars to control for the effects of inflation. Costs incurred after plant retirement, such as decommissioning costs, are included in the model. Outage time was converted to costs using Hydro Québec costs for replacement power during each month of the year from 1999 to 2033.

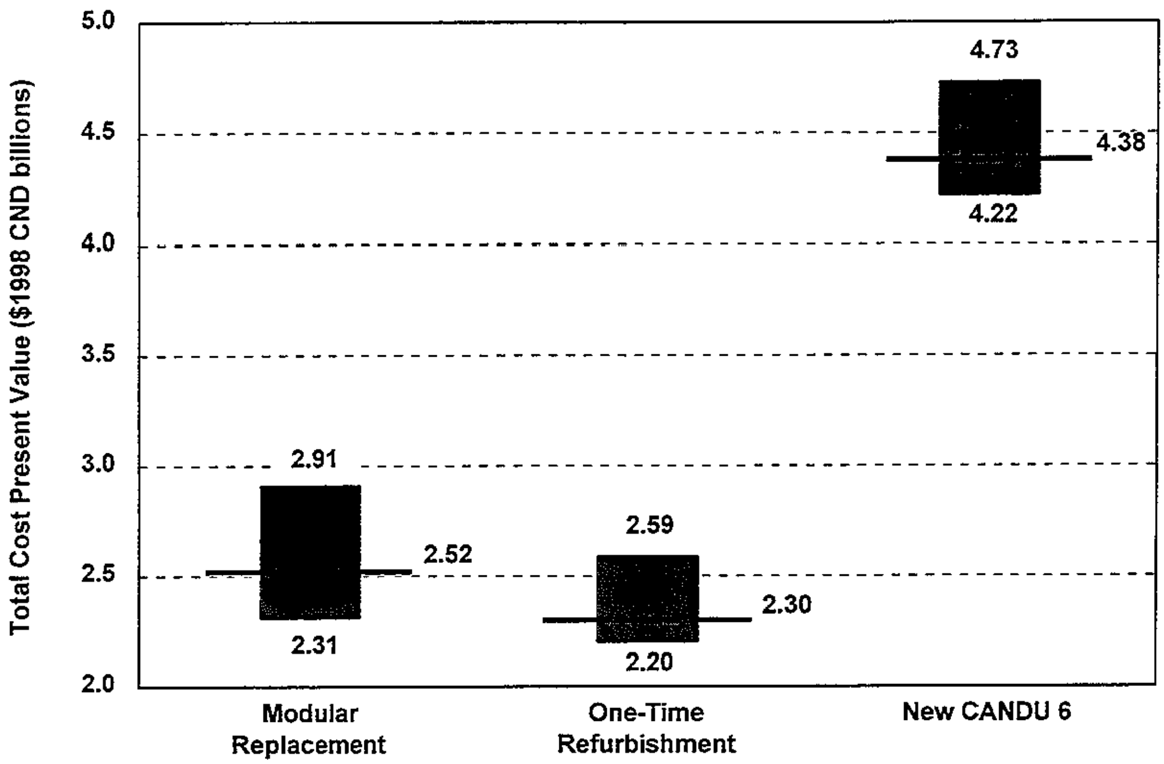
In addition, we estimated the levelized cost per MWh for the one-time refurbishment strategy. The intent of developing this value is to provide a comparison to other alternatives not included in this report. We calculated a value of $27.7 per MWh; however, there are many uncertainties associated with this value. There are difficulties associated with determining the levelized cost as well as problems with comparing this value to other generating resources that may have used different assumptions in calculating a cost per MWh. This cost does not include any replacement power costs.

S.6 CONCLUSIONS

Considering all of the issues discussed above, we identified the range of probable costs for each operating strategy. We discount these costs to the present value in 1998 Canadian dollars. Exhibit S-1 shows the range of probable costs for each operating strategy using the predicted replacement power costs as well as the discount rate currently used by Hydro Québec. In addition, this exhibit shows the comparison among the three strategies.

Exhibit S-1 displays a range of estimated costs as three statistics (median, lowest, and highest cost) for each operating strategy. The median (50 percent) cost estimate is indicated by the horizontal bar. For example, the median cost estimate for Strategy 1, modular replacement of fuel channels, is $2.52 billion. This means that in the 1,000 iterations we simulated, the cost associated with this operating strategy is less than $2.52 billion in 500 iterations, and greater than $2.52 billion in the other 500 iterations. In addition to the median estimate for each operating strategy, the cost range predicted by the model is indicated by the vertical bar. For example, for Strategy 1, the highest observed cost among the 1,000 iterations is $2.91 billion, and the lowest

Exhibit S-1
Comparison of Gentilly 2 Operational Strategies



observed cost is $2.31 billion. The length of the vertical bar shows the magnitude of uncertainty for each scenario.

The median cost for Strategy 1, modular replacement, is $2.52 billion; the median cost for Strategy 2, one-time refurbishment, is $2.30 billion; and the median cost for Strategy 3, a new CANDU 6, is $4.38 billion. All of these costs are discounted to 1998 as are all the costs in this report.

The least-cost alternative is Strategy 2, the one time replacement of the fuel channels. Even though this option does not fully meet the objectives of Hydro Québec because a one-time refurbishment outage is expected to last from 457 to 564 days, including replacement of the calandria tubes, the costs are considerably lower. This was the expected outcome of this project. The modular replacement is forecast to be $221 million more (including replacement power costs) than the one-time refurbishment for the median case.

For Strategy 1, there are some benefits such as operating during the winter; however, the overall time for four outages overshadows this benefit. The cost alone of conducting the modular outages is expected to be at least $90 million more than the one-time refurbishment outage for the median case. The risks and uncertainties are also much higher for the modular case. The range of costs is higher for the modular strategy as well. In addition, this obviously does not take into account lost market opportunities which are significantly higher in the modular outage. The modular approach will result in the station being shut down from 880 to 1,200 days over the four years.

A new CANDU 6 station is forecast to be $2.08 billion more than the one-time refurbishment. There is also high uncertainty associated with building, licensing, and commissioning a new CANDU 6 station, thus the range of costs are greater. In today's regulatory environment, the confidence is not high that a utility can build and commission a new reactor in seven years. In the recent past, cost overruns for new reactors were very high and many nuclear projects were mothballed before completion.

Another important issue is the feasibility of Strategy 1 and the ability for it to meet Hydro Québec's objectives. With today's technology, the modular replacement does not meet the objective of completing the four annual outages in less than eight months. We assumed that further improvements will be made in methodology and the outage duration could be reduced. Thus, we modeled each outage as eight months even though with today's technology, the most likely duration for each annual outage may be higher.

Planning and scheduling for any of the three options is critical. AECL has stated that they need four years to plan a refurbishment outage. If Strategy 1 is chosen, then work would be expected to begin in 2005. Thus, planning should begin in 2001 at the latest. Considering the feasibility issues that must be addressed if this option is chosen, it is prudent to begin as soon as possible. For Strategy 2, planning must begin by 2004 to replace fuel channels in 2008. For Strategy 3, in order to ensure Gentilly 3 is ready and available for operation by 2008, work should begin immediately.

The risk associated with refurbishment is quantified by the uncertainty presented in this report. However, uncertainty can also be qualitatively associated with the material condition of the plant.

S.7 RECOMMENDATIONS

S.7.1 Plant Refurbishment Options

If the plant is to be refurbished we strongly recommend the fuel channels be replaced at one time (Strategy 2). Improvements may be made to the cost and schedule if Hydro Québec negotiates with AECL and collaborates with NB Power. We strongly recommend coordinating outage personnel and tooling with NB Power and possibly Ontario Hydro.

If Strategy 2 is pursued, we recommend:

- begin in the near term
- collaborate with AECL, NB Power, and COG in establishing costs
- negotiate a contract with AECL to further develop tooling and processes.

S.7.2 Plant Material Condition

The following recommendations were not specifically discussed in this Executive Summary; however, we present them here to provide a summary of recommendations included in the report. To obtain additional information, each issue is discussed in the report. These recommendations are intended to assist in planning a refurbishment project as well as to assist in the decision to refurbish Gentilly 2.

- Monitor the deuterium pickup rate closely in the pressure tubes.

- Monitor the feeder thinning issue closely. Determine if pH changes in the Primary Heat Transfer System (PHTS) reduce the feeder thinning rate.

- Evaluate CANFLEX (type of fuel) or critical heat flux (CHF) enhanced fuels to determine if these alternative fuels may prevent the need to derate before the pressure tubes are replaced.

- Conduct a 100 percent eddy current test in the steam generators prior to the refurbishment planning stage. It is more cost effective to replace the steam generators during the one-time refurbishment than to replace them at a later date.

- The feedwater system and the condenser appear to be in good condition; however, eddy current testing will provide indication of the continued condition of these components.

- Develop a regulatory plan to address the Unresolved Generic Action Items with the Atomic Energy Control Board (AECB).

- Monitor the containment concrete issue.

- Collaborate with the rest of the CANDU 6 industry in monitoring and resolving generic industry problems.

- Explore areas where the plant may be vulnerable to significant unknown equipment problems.

GENTILLY 2 STRATEGIC ASSESSMENT
FINAL REPORT

1. INTRODUCTION

Gentilly 2 Nuclear Station (Gentilly 2) has operated for 15 years of its expected 30-year design life. With the station entering the second half of its operating life, plans for future life extension must be addressed. Although the station has operated satisfactorily, major maintenance expenditures are expected over the remaining operating life, and, should the station operating life be extended, such expenditures would continue.

Many questions have arisen as a result of this project. What is the design life of the station and what is it based on? How long can the station be expected to continue operation after a life extension? What should be included in the scope of a life extension and what are the best alternatives for refurbishing the station that will allow it to operate past the original design life into a life-extension period? To address these questions, the overall strategic plan of the station needs to be evaluated. This strategic plan should also match the overall goals of Hydro Québec. Gentilly 2 is 3 percent of the overall generation of Hydro Québec; however, it is an important source of energy during times when replacement power, typically hydro, is not fully available. Gentilly 2 is not subject to hydraulicity experienced by hydroelectric stations and provides a stable source of capacity and energy. Also, the location of Gentilly 2 provides voltage stabilization for the grid.[1] Thus, longer annual outages may be an acceptable alternative to an outage that keeps the station from operating for a year or longer.

Hydro Québec requested Hagler Bailly Consulting, Inc. (Hagler Bailly) to evaluate long-term strategic planning of Gentilly 2. Hagler Bailly is an international consulting firm with staff specializing in both nuclear engineering and economics. We have conducted numerous valuation studies of generating assets for international utilities and other clients. We have assessed the operation of nuclear power plants and recommended strategies to utilities on continued operation. We are one of the leading consulting firms in strategic assessment for utilities and private corporations. The combination of these skills enables us to independently assess the operational strategies of Gentilly 2.

Hagler Bailly developed a model that considers three different operating strategies, specifically:

1. Memo from Yves Filion, Vice President, Production, Transportation and Telecommunications, Hydro Québec, 7/22/94.

1. Operate, maintain, and refurbish the plant by conducting short, modular maintenance outages. The primary issue revolves around replacement of the fuel channels. The pressure tubes (fuel channels) contain the fuel, and the end fittings connect them to the feeder pipes that supply coolant from the steam generators. Each pressure tube is located inside a calandria tube, which separates it from the cold moderator heavy water. These pressure tubes were designed to last 210,000 equivalent full power hours (EFPH).

   In this strategy, a quarter of the pressure tubes and feeder pipes are replaced each year from 2005 to 2008. These dates were chosen because it is expected that at least some of the pressure tubes will need to be replaced by 2008. Thus the most conservative analysis ensures all of the pressure tubes are replaced by 2008. After refurbishment, the station operates until 2033. This is based on the plant life extension management program established by Atomic Energy of Canada, Limited (AECL)[2] (25 years; operation from 2008 to 2033), which are assumed to be the operating years after a refurbishment. If this strategy is considered a suitable option, the feasibility issues must be addressed in detail.

2. Continue operation until major refurbishment of the plant is required. The base case for this scenario would be to operate until 2008 and then conduct a single refurbishment outage. As with the first strategy, after the refurbishment outage the plant will continue to operate until 2033 before permanent shutdown.

3. Provide a comparison with construction of a replacement Canadian Deuterium Uranium (CANDU) 6 nuclear station at the end of the design life or when a major pressure tube/feeder pipe replacement is required. In this strategy, Gentilly 2 is shut down in 2008 and is decommissioned. For comparison purposes, all-in costs of a new station, capital, financing and interest, and operating costs for the station for 40 years operating at 80 percent capacity, and decommissioning costs are estimated at an average cost per MWh value. This cost is treated as a substitute power cost to allow for direct comparison with the other two scenarios.

Our methodology is addressed in Section 2 of this report. Section 3 discusses the modular maintenance outage strategy, Section 4 addresses the one-time refurbishment outage, and Section 5 discusses the strategy of replacing Gentilly 2 with a new CANDU 6 reactor. Section 6 discusses other key issues required for life extension, including equipment, regulatory, and routine costs. Section 7 addresses economic variables and Section 8 describes the model development. Finally, Section 9 presents our results, conclusions, and recommendations. All costs are in 1998 Canadian dollars to control for the effects of inflation. Details on the direct model input, model development, and model operation are provided in a separate confidential document.

2. "CANDU Plant Life Management and Plant Life Extension," B.A. Shalaby and E.G. Price, AECL, Mississauga, Ontario, Canada, 1997.

2. METHODOLOGY FOR EVALUATING IMPACTS ON GENTILLY 2 OPERATION

The intent of our project is to develop a model of Gentilly 2 operations that addresses all of the going-forward costs. The model is intended to be updated in the future as information becomes available. The model is based on Hagler Bailly's Nuc-Optima™ modified to consider specific Gentilly 2 information. The primary structure of the model allows for comparison of operating strategies. The three strategies evaluated are (1) a modular maintenance outage approach, (2) a one time refurbishment outage approach, and (3) construction of a new CANDU 6 to replace Gentilly 2.

For each scenario we address all equipment, regulatory, and routine cost issues that could result in significant costs or outage time. We do not include the cost of initial construction or the continued financing of that cost for Gentilly 2, since these are not considered going-forward costs.

We evaluate many issues in detail to develop the model input. For other issues, information we used was developed during a similar project for New Brunswick Power (NB Power), specifically for Gentilly 2's sister plant, Point Lepreau. The staff at Gentilly 2 reviewed these costs and we revised some costs to be more indicative of those for Gentilly 2.

We did not explore areas where the plant may be vulnerable to significant unknown equipment problems. We recommend a second phase of the project to explore all of the possible equipment problems that may occur, but were not analyzed as part of this project.

2.1 STRATEGY 1 — MODULAR MAINTENANCE OUTAGE

We evaluated the conduct of a major refurbishment outage on a modular basis. This entails replacing one quarter of the fuel channels during annual outages for each of four years. To consider this strategy as an option, we identified costs and outage impacts and addressed the feasibility of this approach. Thus, the following tasks were completed to evaluate a modular maintenance outage:

- We identified preliminary feasibility issues.
  - We discussed the costs and outage time associated with a modular maintenance outage strategy with Hydro Québec staff.
  - We discussed the feasibility of the modular maintenance outage strategy with regulatory and technical staff at Hydro Québec.
  - We discussed the information required initially to consider this strategy with AECL.

- We included the information provided by AECL as model input.
- We reviewed all other equipment, regulatory, and routine costs issues with respect to this strategy.

2.2 STRATEGY 2 — ONE-TIME REFURBISHMENT OUTAGE

The second strategy considered is the replacement of all of the fuel channels at one time. The technical uncertainties are fewer for the one-time refurbishment outage approach since it has been done before at Ontario Hydro's Pickering Nuclear Station, and AECL has since developed additional techniques that will reduce costs and outage time.

Since the intent of this analysis is to provide a comparison of the three operating strategies, we used work previously done for NB Power by AECL. This work estimated the costs and outage time associated with replacing the pressure tubes, feeder pipes, and calandria tubes. The estimates include a fixed price contract from AECL that was negotiated between AECL and NB Power. Since this is a fixed price contract very little uncertainty was associated with this scope of work. However, there is also a significant scope of work that must be completed by the utility. This scope of work is site-specific and we modified the scope of work for Point Lepreau to fit Gentilly 2. We considered site-specific issues such as higher radiation fields at Gentilly 2.

This strategy replaces the fuel channels at one time. This outage will last between one to one and a half years. The strategy begins in 2008 and ends in 2009 and the plant is then operated until 2033.

2.3 STRATEGY 3 — REPLACE GENTILLY 2 WITH A NEW CANDU 6 REACTOR

The third operating strategy is to operate Gentilly 2 as long as possible before the fuel channels require replacement and build a new CANDU 6 reactor to replace the generation.

AECL provided a rough cost estimate of the overnight (no interest and financing) costs of building a new CANDU 6 reactor. We used these costs in addition to costs incurred to operate the new unit to develop a cost per MWh. We also estimated interest and financing charges. We modified the model to allow for differences in operating strategy if Gentilly 2 is shut down and Gentilly 3 is started up. The costs included in the Gentilly 3 estimate are:

- AECL's estimate of overnight costs
- interest and financing
- licensing and commissioning

- continuation of annual routine operation, maintenance, and administration (OM&A) and capital
- routine outage costs
- probability of equipment failures at the new unit
- new fuel
- irradiated fuel management
- decommissioning.

2.4 OTHER ISSUES

For each operating strategy, we addressed specific equipment, regulatory, and routine cost issues. Each issue was analyzed for each operating strategy and consideration was given to the possibility of other issues that arise specifically because of that operating strategy (i.e., additional decommissioning costs for a new CANDU unit).

2.4.1 Equipment

We address seven specific systems in detail for Hydro Québec. These include:

- pressure tubes
- feeder pipes
- steam generators
- turbine generator
- containment
- feedwater system
- condenser.

As part of our evaluation of these systems and components, we interviewed Gentilly 2 staff to identify the specific areas of concern.

Other equipment issues are included in the base model. In developing the base model, we identified major areas of potential concern to determine the probability of planned and unplanned outages over time and the distribution of outage durations and material and labor costs. To determine the risk of major outages and costs, we also considered high-impact random failures and the potential for nonroutine planned outages. The base model was developed for Point Lepreau and revised for Gentilly 2. These costs and outage times were reviewed by Hydro Québec staff and modified accordingly.

For each equipment issue, we addressed probability of occurrence, timing, cost, and outage duration information. As appropriate, we developed probability distributions for these data.

In developing the base model issues we conducted interviews with outside organizations. These organizations included the University of New Brunswick, AECL (staff in Mississauga and Chalk River), Atomic Energy Control Board (AECB or the Board), Ontario Hydro (staff at Darlington Station and Headquarters), CANDU Owners Group (COG), NB Power, and equipment vendors.

Probability of occurrence was estimated using historical information from CANDU units or, where applicable, U.S. experience. For example, historical information on CANDU units includes about 345 unit-years of operation. There have been seven unplanned pressure tube replacements at these units.[3] Thus, the average probability of an unplanned pressure tube replacement in any year is 7/345 or 0.02. For equipment that is similar to light-water reactor components, we used OPEC (Operating Plant Experience Code) data to develop the probability of occurrence. OPEC is a proprietary database owned and operated by Hagler Bailly that compiles information on all outages and derates at U.S. nuclear power plants.

In estimating outage durations and equipment repair times, estimates were obtained using either historical information on similar projects or expert opinions. We requested this information from both Gentilly 2 staff and outside organizations. Our methodology obtained estimates of the minimum, nominal, and maximum values for a particular issue. To help quantify these values, the minimum is typically defined as the value where there is only about a 10 percent chance of being less than the minimum, the maximum is defined as the value where there is only about a 10 percent chance of being greater than the maximum, and the nominal is defined as the most likely value. This methodology provides an 80 percent confidence level (80 percent probability) that the value will be between the minimum and maximum values.

Many of the probability distributions in the model are described as lognormal distributions. The nonsymmetrical property of the lognormal distribution makes it valuable in describing the probability distributions for equipment outage durations, equipment repair costs, and planned outage durations and costs. Lognormal distribution usually fits these issues because outage durations or costs have a greater potential for having very high values than for having very low values. It reflects the greater likelihood that a problem will occur that will increase the outage durations and costs as opposed to the situation in which everything goes well. This approach provides the most conservative value.

3. This does not include the experience at Douglas Point since it was a research reactor, replacements at Pickering 3 and 4 in 1974 since they were research replacements, or the replacement of fuel channel K05 at Point Lepreau in 1987 since it was replaced for research purposes.

2.4.2 Regulatory

Our intent in addressing regulatory issues was to capture probable analyses and modification costs required to continue operating the plant in today's environment as well as to allow for a life extension. Many of the issues are generic industry problems that are faced by all CANDU operators. To develop this initial data, we evaluated regulatory action item lists and identified issues, the resolution of which require either significant analyses or plant modifications. We evaluated the potential for increased AECB involvement and license renewal issues. We used data compiled for NB Power modified to ensure that the site-specific issues were addressed for Gentilly 2. We discussed the issues with Hydro Québec and evaluated areas where there were thought to be differences in the Hydro Québec and NB Power approach to resolution. We developed a probability distribution of the cost and outage time for each identified issue.

2.4.3 Routine Costs and Outages

Routine costs and outages include routine annual OM&A costs, routine annual capital expenditures, annual planned outages, other scheduled and forced outages, fuel costs, intermediate and low level waste (LLW) disposal and storage costs, irradiated fuel management (IFM) costs, and decommissioning costs.

For each of these areas we evaluated the current situation at Gentilly 2 and developed probabilities of future costs and outage durations.

3. MODULAR MAINTENANCE OUTAGE STRATEGY

Factors involving the pressure tube replacement that must be addressed include specific technical issues, timing of the replacement, feasibility issues, costs, and outage time. AECL provided background information as well as the cost estimates for replacing fuel channels using this modular approach. The information that AECL provided is to be considered a preliminary overview of the issues and options available if fuel channel replacement is performed over several outages rather than during a one-time refurbishment outage. AECL provided an outline of the program and described the key elements of duration and scope of work, and defined the interfaces between AECL and Hydro Québec. The cost estimates provided are deemed to have a level of certainty appropriate for planning purposes. The options considered were:

- half core retubing
- quarter core retubing
- multichannel replacement.

Of these three replacement scenarios, we determined that replacing one quarter of the core each year for four years was the operating strategy that best matched Hydro Québec's operating goals. The primary reason for choosing this strategy is that this strategy requires the station to be shut down for "only" eight or nine months of the year, allowing operation during other, more critical, months. This strategy has outages beginning in 2005 and ending in 2008 for reasons discussed below. After refurbishment, the station is operated until 2033.

3.1 TECHNICAL ISSUES

The technical issues associated with the lifetime of the pressure tubes are summarized below.[4,5] Gentilly 2 has addressed these issues with a detailed inspection and monitoring program that results in identification of the progression of any degradation. This should allow actions to be taken to correct degradation before further limiting conditions.

3.1.1 Sag

The pressure tubes and the calandria tubes in which they are contained sag over time because of irradiation induced creep, the operating temperature of the pressure tubes, and gravity. One consequence of this sagging of the pressure and calandria tubes is the potential that some pressure and calandria tubes may have to be replaced because of contact with the horizontal flux detector guide tubes and liquid injection (LISS) nozzles. Possible replacement of a limited number of pressure and calandria tubes before a large-scale replacement may be required and is addressed in the model. The pressure tube replacement tooling is currently qualified to insert new pressure tubes into a calandria tube with a maximum sag of 50 mm. With improved tooling, this could be increased to 75 mm. On a conservative basis, 50 mm could occur at 154,000 EFPH and 75 mm will most likely not occur until the end of the pressure tube life at 210,000 EFPH. This could limit the pressure tube replacement to the 2005 time frame without improved tooling or simultaneous replacement of calandria tubes.

3.1.2 Diametrical Creep

The pressure tubes also grow in diameter because of irradiation induced creep and the operating temperature. With a larger diameter, some coolant flow bypasses the fuel bundles in the increased gap between the fuel bundles and the pressure tube inner wall. This leads to higher fuel operating temperatures and reduced safety margins, which could require derating to maintain control within acceptable limits. Two measured fuel channels at Gentilly 2, P16 and L09, are showing higher than anticipated diametrical expansion. The combination of flow bypass and reduced coolant flow rate from other heat transport system degradation factors has exceeded the

4. Programme De Suivi Des Tubes De Force — Mise a Jour 1997, Gentilly 2 Rapport Technique Interne, G2-RTI-97-54, 97-12-17.

5. Gentilly 2 Management of Pressure Tube Degradation Issues, AECL Report, 66-31100-655-005, 1997 October.

current licensing margins at Gentilly 2. As a result, a derating of Gentilly 2 is in place. Much of the reduction in the coolant flow rate has been recovered with the repair of the steam generator divider plates in 1995. The remaining reduction in the coolant flow is anticipated to be recovered by the primary side mechanical cleaning of the steam generator tubes planned for the 1999 outage. However, even if all of the coolant flow rate is recovered, it is likely that continued diametrical expansion will result in additional derating of the reactor in the future. If a new fuel design (i.e., CANFLEX or CHF-enhanced) is licensed, derating is not expected to be required.

3.1.3 Axial Creep

The pressure tubes also grow in the axial direction because of irradiation induced creep. One end of the pressure tube is fixed and the other end is allowed to grow for both axial creep and differential thermal expansion. In the 1998 planned outage, Gentilly 2 swapped the end of the pressure tubes that is fixed to the other end. The measured axial growth rates at Gentilly 2 appear to be very linear and linear extrapolation with the measured growth indicates that this would not be a problem until about 2013. If a more conservative growth model is used, then a small number of pressure tubes at Gentilly 2 might reach the end of the available bearing in about 2007. It may be possible to demonstrate that the tubes will not hang up and will go back on bearing during cool down. It is also possible to change out a few limiting tubes or to operate for some time with the highest growth channels defueled. These options are costly in terms of either direct costs, down time, or the need to derate the plant.

3.1.4 Deuterium Pickup in the Pressure Tubes

Deuterium pickup in the pressure tubes makes the pressure tubes more susceptible to failure by delayed hydride cracking (DHC). AECL has recently developed a new "Design Equation" to predict the deuterium concentration in the pressure tubes as a function of time in service.[6] The rate at which the concentration increases was previously assumed to be constant (linear increase with time), whereas the new Design Equation has the rate increasing more quickly with time. If the new Design Equation is valid, the limiting deuterium concentration, the Terminal Solid Solubility (TSS) Threshold, of the Fitness-For-Service Guidelines[7] could be reached in late 2008. The TSS Threshold is the limit where the deuterium ingress buildup exceeds pressure tube design limits. Deuterium buildup in pressure tubes arises from corrosion on the coolant side as well as deuterium ingress from the annulus gas. This deuterium ingress can result in delayed hydride cracking, blister susceptibility, and reduced fracture toughness. Measurement of the

6. Bahurmuz, A.A. et al., "A Design Equation for Predicting Corrosion and Deuterium Ingress in Pressure Tubes (Rev. 1.0)," AECL RC-1551, COG-95-596, September 1996.

7. AECL Memo, A.A. Bahurmuz and V.F. Urbanic to W.R. Clendening, "Deuterium Pickup in Bruce and CANDU 6 Pressure Tubes," RMR-97-239, 7/11/97.

scrapings done in 1998 at Gentilly 2 have shown indications that the new Design Equation may be valid. As of June 1998, inspection techniques and results are being reviewed.

3.1.5 Pressure Tube to Calandria Tube Contact

The pressure tubes are held concentric with the calandria tubes by a number of "garter spring" spacers along the pressure tube. If the pressure tube comes in contact with the calandria tube, zirconium hydride blisters may form, which can result in failure of the pressure tube. Gentilly 2 has used a number of short campaigns to reposition the garter springs for individual pressure tubes before reaching any limiting condition. Garter spring repositioning was performed in 1991, 1995, 1996, and 1997. The 1997 repositioning was done at the end of February rather than in May as originally planned because of new data on the formation of blisters. During the 1998 outage, the possible increase in deuterium pickup rate prompted an outage extension to reposition all of the spacers in the remaining channels to ensure no calandria to pressure tube contact.

3.2 TIMING OF FEEDER PIPE REPLACEMENT

The outlet feeder pipes are experiencing significant thinning due to flow assisted corrosion (FAC). This was an original design consideration; however, the rate of thinning is higher than originally anticipated. The costs and outage time for pressure tube replacement are not markedly increased if the feeders are also replaced at the same time, and their removal would greatly facilitate the access to, and the replacement of, the pressure tubes. It is assumed that all of the feeders are replaced at the same time as associated pressure tubes. The model addresses the possibility that feeders may require replacement before the refurbishment because of cracking. Gentilly 2 staff believes that there is no evidence that the feeder pipes will require replacement because of feeder thinning before the refurbishment outages occur. However, if it becomes an issue in the future, the model can be modified to include replacement costs of designated feeder pipes before a major refurbishment outage.

3.3 TIMING OF PRESSURE TUBE REPLACEMENT

The station is expected to reach nominal "end-of-life" around 2012. This is when the station's operating duration will exceed the original design life of 210,000 EFPH. The original design life is based on the expected condition of the pressure tubes after 210,000 EFPH. To validate this design criteria, the pressure tube condition is routinely monitored. Because of the issues discussed above, the design criteria and more specifically, the deuterium pickup for the pressure tubes are now expected to limit the pressure tube life to about 2008, if not earlier. Thus, we assume in our model that the pressure tube life is until 2008 and that pressure tube replacement would be required before that time. Pressure tube outages to replace 25 percent of the tubes per year must begin in 2005 to allow for replacement of all pressure tubes by 2008. Future inspections may assist in refining this timing.

Coordinating with outages at NB Power and Ontario Hydro will further reduce costs and gain efficiencies in the process.

3.4 FEASIBILITY ISSUES

3.4.1 Calandria Tube Replacement

A critical issue with the modular approach is the ability to replace the calandria tubes. The current methodology does not allow for draining the calandria because fuel is left in the channels not scheduled for replacement during the outage (the other three-quarters of the core).

When the pressure tubes are replaced, the relatively thin-walled calandria tubes are forced back into their original straight position with no sag because the much stronger pressure tube is inserted inside of the calandria tubes. However, after about five years, the new pressure tubes and old calandria tubes will be sagged to a pre-retube condition.[8] This produces a number of potential problems as described below.

1. The continued sagging of the calandria and pressure tubes will result in contact between the calandria tubes, the horizontal detector guide tubes, and the LISS nozzles several years after the pressure tube replacement. To alleviate this problem, AECL has considered[9] that, as an option, the 38 calandria tubes in rows F and Q above these horizontal guide tubes and LISS nozzles be replaced during the pressure tube replacement. This causes some complications with the modular approach because the calandria must be drained to replace calandria tubes. The approach suggested by AECL is to remove and flask the calandria tube at both ends simultaneously.

2. The pressure tubes will exceed the sag limit for the tooling used to replace a pressure tube in a sagged calandria tube. As a result, replacement of single pressure tubes because of degradation after some years of operation may be much more difficult.

3. With increased sagging of the pressure and calandria tubes, additional stresses would be placed on the calandria tubes during a single pressure tube replacement. These increased stresses may increase the potential for a failure of a calandria tube.

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8. Excerpts from "Ontario Hydro Nuclear Retube Breakthrough Initiative C Assessment of Expected OHN Unit Fuel Channel Lifetimes," 00-31100-600-025, Revision 1, April 1997.

9. Scott, D.A., "Point Lepreau Feeder & Pressure Tube Replacement — Outline Proposal," November 1997.

4. Increased sagging may introduce problems with passing the fuel elements through a highly sagged pressure tube that has not experienced as much growth in the pressure tube diameter.[10]

5. There may be problems with the analysis of the core physics with highly sagged pressure tubes.

In addition to the above issues, the ductility of the calandria tube weld for long-term operation is questioned. The AECL assessment of the calandria tube lifetime[11] states in the abstract that, "although the ductility, especially of the weld, becomes very low, the data suggest that most of the changes to mechanical properties take place before one pressure tube lifetime. More information on this topic will be obtained from the current COG program." We are concerned that ductility of the weld material is very low, less than 1 percent burst strain, at 15 years of operation, and will become lower with continued operation. No data beyond 15 years are presented, and extrapolation to 50 to 60 years is tenuous. We believe it would be prudent to explore this further and to consider replacing all of the calandria tubes.

Improved calandria tubes are under development, with the focus on strengthening the weld or eliminating it.[12] The replaced calandria tubes should therefore have better performance than the current calandria tubes.

3.4.2 Feeder Replacement, Positioning, and Clearances

Adequate feeder clearances must be maintained to allow for the axial growth of the pressure tubes during the life of the fuel channel after replacement.

For a standard full core retubing, the feeder positions and clearances are set back to their nominal start-of-life conditions; however, for staged retubing, channels will have to be grouped in sections that take into account their attached feeders. Feeders are grouped in "banks" of up to 10 lines with the feeders closest to the reactor face connecting to channels closest to the reactor centerlines. Because of this, the installation process for replacement feeders will have to start from the center channels and work its way out to the periphery.

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10. Excerpts from "Ontario Hydro Nuclear Retube Breakthrough Initiative C Assessment of Expected OHN Unit Fuel Channel Lifetimes," 00-31100-600-025, Revision 1, April 1997.

11. Coleman, C.E. et al., "Assessment of the Lifetime of Calandria Tubes," AECL, RM-FCCB-50, December 1996.

12. Coleman, C.E. and B.A. Cheadle, "CANDU Fuel Channels," AECL-11755, January 1997.

3.4.3 Fueling Machine Interference

New fuel channels will be installed to allow for maximum axial growth. They will be set to their original axial positions with the inboard journal ring sitting fully forward in the lattice tube bearing. Since new channels will be adjacent to original channels, some new end fittings will be as much as 3 inches further inboard than adjacent end fittings of channels whose replacement is left for a subsequent outage. With its current design, the fueling machine cannot accommodate this relative displacement between adjacent channels. This means that either the fueling machine will have to be redesigned, or the new end fitting must be lengthened.

Lengthening the end fitting will be a fairly straightforward exercise; however, there will be some constraints on the new design. The feeder port location will have to be set to its original plane to ensure that feeders do not become overstressed over the life of the fuel channel; and the closure plug must remain in its current axial position relative to the outboard end fitting face to accommodate the fueling machine. The shield plug, however, can be moved up to 2.4 inches inboard of its current axial location (relative to the e-face) without modifying the CANDU 6 fueling machine. This means the overall length of the fuel cavity will increase by about 1.2 inches. Given that the new channel will require a 1-inch longer cavity than that originally installed in Gentilly 2, the gap is only 0.2 inches longer than on the current new reactor installation. The longer gap is necessary to allow for thermal expansion of the fuel string in the event of a Loss of Coolant Accident (LOCA) where all cooling to a new fuel channel is lost.

In addition to this, the reactor will also require an extra 17 cubic feet of heavy water to fill the extra volume caused by the longer end fittings.

3.4.4 Isolation and Draining

An important factor in staged retubing will be the ability to isolate and drain individual, or groups of, fuel channels. It is essential to drain only the feeders and channels that are to be replaced and their associated headers. For this reason the reactor face must be sectioned for retubing in groups of channels on the same header system. Replacing a quarter of the core that are on the same header is the best approach to address this issue.

3.4.5 Reactor Physics Considerations

With the replacement of a partial reactor core, the fuel burn-up characteristics become critical. Part of the core will have completely new fuel while the rest of the core will have partially spent fuel. This will cause imbalances in reactor physics parameters. To counteract the effects of the new fuel, operating at a derate may be necessary. To address this issue we assume a 10 percent derate is necessary after the first quarter of the core is replaced until after the final quarter of the core is replaced.

3.4.6 Radiation Fields

During a modular replacement, three quarters of the reactor fuel channels will remain in place with fuel. Hence, general radiation fields are expected to be higher than for a one-time replacement. To reduce localized radiation fields, a combination of modular shielding (such as lead blankets and patches) must be used in conjunction with shielding cabinets.

3.5 COST OF A MODULAR LARGE-SCALE PRESSURE TUBE AND FEEDER REPLACEMENT

The estimated total costs for a modular large-scale pressure tube and feeder replacement range from $342.8 to $423.2 million with a most likely cost of $380.9 million. It is recognized that some of these costs will be spent in earlier years for planning, materials, and tooling. For the purposes of our analysis it is assumed that 20 percent of these costs are incurred for planning purposes during the three years before the replacement, and 20 percent is spent in each of the four sequential years of the modular replacement.

3.6 OUTAGE TIME FOR A MODULAR LARGE-SCALE PRESSURE TUBE AND FEEDER REPLACEMENT

The outage time required for this approach is significant. The outage time for the AECL scope of work is about four months for each outage; however, the time required for Hydro Québec's scope of work is significant. One quarter (or possibly one-half) of the core must be defueled, drained, and decontaminated before work begins. Efficiencies and overlaps will have to be explored to make this option plausible. In addition, the reactor core must then be refueled, filled, and tested for recommissioning. Thus, the uncertainty of this approach as well as the potential for problems during each of the four shutdowns means that an outage from 8 to 10 months is expected; however, an even longer outage could occur. We modeled the median as eight months, even though many improvements would have to be made to reduce necessary defueling and refueling. We included the possibility for one of the four outages to last for 12 months. Over the four years of modular outage time, the station could be shut down for 880 to 1,200 days.

4. ONE-TIME REFURBISHMENT OUTAGE STRATEGY

Large-scale or one-time replacement of the pressure tubes and feeder pipes is expected to take more than one year; thus this approach does not meet Hydro Québec's objective of ensuring the plant will be available during the winter months. However, it is the most efficient and more certain method of replacement of the pressure tubes. The approach has been used at Ontario Hydro's Pickering Station and both the Hydro Quebec and the AECL costs would be much lower.

4.1 COST OF A ONE-TIME PRESSURE TUBE AND FEEDER REPLACEMENT

We estimated the costs and outage duration for a one-time pressure tube and feeder replacement based on an independent AECL estimate. The draft Outline of Proposed Agreement provided by AECL[13] includes estimates based on the Fast Channel Replacement (FCR) technology developed by AECL.

For NB Power, AECL is prepared to convert their proposal price to a fixed price at the time of the start of the work. We assumed the same for Hydro Québec. We adjusted the AECL proposal price to include all of the remaining Hydro Québec costs associated with a one-time pressure tube and feeder replacement by adding the following:

- remaining value of fuel discharged for refurbishment
- Gentilly 2 additional staff, materials, and purchased services costs
- contingency on Gentilly 2 costs
- corporate overhead on Gentilly 2 costs
- interest costs.

Because of the firm price provided by AECL, the uncertainty surrounding the costs is low and we estimate a range of all-in costs for the refurbishment from $297 million to $334 million. This cost range includes AECL and Hydro Québec costs.

In addition, our model assumes a 90 percent probability that the calandria tubes will be replaced. Even if all of the calandria tubes do not require replacement, a minimum of 38 calandria tubes will be replaced because of possible sagging and contact with horizontal flux detector guide tubes or LISS nozzles. The costs stated above include replacement of all calandria tubes.

4.2 OUTAGE TIME FOR A LARGE-SCALE PRESSURE TUBE AND FEEDER REPLACEMENT

AECL provided an estimated duration for their work with an incentive clause for completion on or under schedule as well as a penalty clause for completion over schedule for the NB Power work. We assume the same for Hydro Québec. This reduces the uncertainty in the duration of the outage. However, more than half of the total outage time is not within the AECL scope of work. We assume the range of outage time is from 457 to 564 days. This includes time required to replace calandria tubes.

The considerations for the timing of a one-time replacement of the pressure tubes and feeders in a single long outage are similar to those described in Section 3.1. However, the technical uncertainties are fewer for the one-time replacement since it has been done before at the

13. AECL Letter, Gary Kugler to R.M. White, "AECL Proposal for Retubing of Point Lepreau," 2/19/98.

Pickering CANDU station. For similar reasons, the costs and outage durations for the one-time replacement outage approach are more certain than for the modular approach.

5. NEW CANDU 6 REACTOR REPLACEMENT STRATEGY

We include costs of Gentilly 2 until 2008 and then develop a substitute power cost for Gentilly 3. This cost was calculated as a cost per MWh in order to substitute for Gentilly 2 from 2008 to 2033. To accomplish this calculation we must include all costs for the new unit.

AECL provided a preliminary estimate of the overnight costs of a new CANDU-6 reactor (referred to as Gentilly-3 in this report) to replace Gentilly 2. The total overnight cost (costs not including financing and interest) estimate is $1.912 billion. This cost does not include the following:

- financing and interest costs
- licensing
- commissioning
- training
- traditional owner's scope (e.g., land, permits)
- common facilities (e.g., simulator, D2O upgrades, river water intake structure).

It does include:

- engineering and project management
- initial fuel load and heavy water.

We added costs for licensing and commissioning of the reactor. We also included decommissioning and spent fuel storage costs. Annual routine outage costs, OM&A, fuel, and capital costs are assumed for the new Gentilly-3 unit. For these costs we assume a continuation of costs at Gentilly 2. We added rough estimate of the interest and financing charges. In addition, a rough estimate of additional equipment and regulatory costs was assumed. In this strategy, we assumed an 80 percent capacity factor for 40 years. It should be noted that this is the expected life of the new CANDU 6 units.[14] These costs do not include large-scale replacement of the fuel channels. If this strategy were to be chosen, a contract should be negotiated with AECL guaranteeing the 40-year life of the pressure tubes.

From this information a median cost of $81.21/MWh was developed to construct, operate, finance, and decommission a new unit. Using a cost/MWh allows the model to use this as a substitute power cost for Gentilly 2 from 2008 to 2033. This analysis ignores the final 15 years that Gentilly 3 will be able to operate incorporating neither costs nor benefit for that period.

14. "CANDU Plant Life Management and Plant Life Extension," B.A. Shalaby, E.G. Price, AECL, Mississauga, Ontario, Canada.

6. OTHER ISSUES

The other issues have been categorized as equipment, regulatory, and routine cost issues.

6.1 EQUIPMENT ISSUES

In addition to addressing pressure tubes, feeder pipes, and calandria tubes, five equipment issues specifically analyzed for Gentilly 2 were:

- steam generators
- turbine generator
- containment
- feedwater
- condenser.

Of these issues, we considered the following three ways that they could impact costs and outage time.

1. possible equipment failures based on historical failure rates

2. potential future outages or maintenance expenditures because of aging not included in budgeted OM&A

3. possible design upgrades.

These specific equipment issues address the areas where the highest costs and outage time are expected to occur.

We addressed 17 other equipment issues based on work already completed for NB Power. Out of these components and systems, we identified the following six specific equipment issues that are expected to have, or have the potential to have, a future impact on costs and outage time. These are in addition to the specific equipment issues addressed in detail.

1. calandria tube and pressure tube replacement because of sagging and contact with horizontal flux detector tubes or liquid injection safety system (LISS) nozzles

2. individual unplanned pressure tube replacement

3. emergency diesel generator failure

4. station computer replacement

5. cable replacement

6. plant equipment aging program.[15]

For each of these issues we identified the probability of specific costs and outage duration as well as the timing and probability of occurrence of those variables. This information was input into the model to yield our results and conclusions. Some of the equipment issues warrant additional discussion in this report and are addressed in the section below.

6.1.1 Steam Generator Replacement

Background

The Gentilly 2 steam generators are currently in very good condition. The steam generators employ Incoloy alloy 800 TT tubes. The Gentilly 2 secondary system has a condenser with admiralty brass tubes. The high-pressure feedwater heaters have carbon steel tubes, and the low-pressure feedwater heaters have stainless steel tubes. These features are consistent with the best design features to ensure the best possible operating conditions for steam generators. In addition, the steam generators have been well maintained.

The combination of the steam generator design, the secondary side design, and the water chemistry used has been very successful in preventing any major degradation of the steam generator tubes. Of the 14,200 tubes in the four steam generators (the component that typically fails in the steam generators), only three tubes have been plugged because of degradation and no tube leaks have occurred.

Because of the material and design and the unique water chemistry used, the likelihood is high that the steam generators will be able to operate for an extensive period of time without requiring replacement.

Probability of Requiring a Steam Generator Replacement

As demonstrated in the previous section, the steam generators at Gentilly 2 are in very good condition. Assuming the water chemistry program and periodic cleaning and tube inspections are continued, the steam generators should last well beyond their design life of 30 years at an 80 percent capacity factor. It is therefore very unlikely that the steam generators will need to be replaced in the near term, and we estimate that there is zero probability that the steam generators will require replacement during the refurbishment outage.

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15. The plant aging program is in the process of development at Gentilly 2. This program will identify the condition of all important equipment allowing for time to take action required to ensure equipment continues to function properly into the future.

It is questionable whether the steam generators could last for the entire plant lifetime if operations are extended to 2033. For the purpose of our analysis, it is assumed that there is a 10 percent probability that the steam generator will require replacement.

Outage Time for Steam Generator Replacement

In the last 10 years, 12 steam generator replacements have been completed and one is currently in progress in the United States. For this analysis, the experience in the last 10 years has been used since there have been some improvements in the outage durations and costs required for replacing the steam generators. For the purposes of this analysis, we assume a steam generator replacement will take from 65 to 257 days with a most likely duration of 129 days.

Cost of Steam Generator Replacement

B&W Canada has supplied a cost for four new steam generators. This cost includes engineering, licensing, manufacturing, and delivery to the site. It does not include installation costs, which are a major cost item. To estimate the costs of installing four steam generators, we considered the U.S. experience and developed an estimated cost for Gentilly 2 between $180 and $244 million with a most likely cost of $201 million.

6.1.2 Main Turbine

Background

The Gentilly 2 main turbine and generator is a General Electric design unit. Alignment problems required planned outages in 1983, 1985, 1987, 1991, and 1998. The durations of these outage ranged from 6 to 20 weeks. The duration of many of the other planned outages has been extended for about a week to correct misalignment problems. However, future annual planned outages will each require about one week.

The main turbine appears to be in very good condition and with continued careful preventative maintenance it should be able to operate well beyond its initial planned life of 30 years at an 80 percent capacity factor. The draft plant life extension planning (PIME)[16] document identified the potential replacement of the turbine controls in about 2008 if the life of Gentilly 2 is to be extended beyond the initial planned life. The direct cost for this change is estimated to be $1.36 million. This cost is included in the miscellaneous costs for the outages where the pressure tubes and feeders are replaced.

16. PIME — Program Programme des Inspections et de Maintenance Exceptionnelle des ssc Critiques, DR-39.

Probability of a Major Main Turbine Outage

To obtain an estimate of the probability of a major outage due to a problem with the main turbine, U.S. experience was used.[17] The probability of a major main turbine outage is 0.0096 for each unit-year.

Outage Time for a Major Turbine Outage

We estimate the outage time required for a major turbine outage by starting with experience at U.S. plants and adjusting it to CANDU units. We estimated the number of days between 24 and 154 with a most likely duration of 61 days.

Costs of a Major Turbine Outage

An approximate estimate of the material and additional labor costs for a major turbine event is between $0.5 million and $12.75 million with a most likely cost of $1.78 million.

6.1.3 Main Generator

Background

The problems with maintaining alignment, as described above, have also affected the generator, but these problems are expected to diminish in the future. A copper dust inspection and vacuuming of the rotor was performed in 1991, but the rotor remained contaminated. In 1992 a forced outage occurred because of copper dust contamination. During the outage, the rotor was rewedged and modified to include a layer separator between the bars. A visual inspection of the generator internals and a stator bar leak test were performed in 1996. The stator was pressure tested and rewedged in 1997. The rotor end retaining rings were replaced with rings that are not susceptible to stress corrosion cracking, which has been an industry problem.

The main generator appears to be in very good condition and with continued careful preventative maintenance should be able to operate well beyond its initial planned life of 30 years at an 80 percent capacity factor.

Probability of a Major Main Generator Outage

To obtain an estimate of the probability of a major outage due to a problem with the main generator, U.S. experience was used.[18] The probability of a major main generator outage is 0.013 for each unit-year.

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17. Hagler Bailly nuclear unit database Operating Plant Evaluation Code — OPEC.

18. Hagler Bailly nuclear unit database Operating Plant Evaluation Code — OPEC.

Outage Time for a Major Generator Outage

Using U.S. experience modified to CANDU experience, we estimate the outage time between 30 and 82 days, with 56 days being the most likely scenario.

Costs of a Major Generator Outage

Costs were estimated by considering materials and labor needed to repair the major causes of a generator problem. As a minimum, the costs of replacing one stator water cooling header was used. As a maximum, the costs of rewinding the generator was used. We estimate the costs to be between $0.71 million and $6.28 million with a most likely cost of $2.11 million.

6.1.4 Containment Structure

Background

The containment structure at Gentilly 2 represents one of the most significant unknowns with regard to extending the life of the station beyond its original lifetime. A leak-rate test is periodically conducted to demonstrate the ability of the containment to perform its design function at the current time, but yields little insight into the containment's ability to provide this function for an additional 40 or 50 years.

The original plan was to perform an integrated leak-rate test every five years. The 1985 test was slightly over the limit of 0.5 percent volume per day leak rate. Because the 1985 reactor building leak rate was higher than the design limit leak rate, the AECB required a more frequent test interval.

The higher-than-design reactor building leak rate was due to the deterioration of the epoxy liner. Eighty percent of the liner has now been replaced with a polyurethane-based material (Normac), which is more flexible and bridges gaps better. The new liner material was installed starting in 1989. The tests results in 1990 and 1993 (with 54 percent of the liner replaced) and in 1997 (with 80 percent of the liner replaced) were below the leak rate limit.

Gentilly 2 has installed equipment that allows an on-line measurement of the reactor building leak rate. Extensive testing has demonstrated that the reactor building leakage rate has stabilized. The combination of the additional tests and the on-line measuring equipment may allow the full-pressure test frequency to be extended to at least every five years. Returning to a five-year test would be desirable for retaining the long-term condition of the containment. Each full-pressure test of the containment most likely results in some degradation on the outer surface of the containment structure.

AECL has issued a preliminary draft report on aging of containment structures at the Gentilly 2 and Point Lepreau plants.[19] This report indicates that there may be some age-limiting problems with the Gentilly 2 containment, primarily due to the concrete used in the construction of the reactor building. To protect the concrete, a coating was applied to the exterior of the concrete to help stabilize the material.

The preliminary draft of the AECL containment aging study recommends a detailed aging program. A detailed aging program is required to identify the condition of the containment structure and its ability to last well into the future.

Probability of a Containment Structure Outage

It is unlikely that the containment structure will cause an unplanned plant outage. The periodic leak-rate tests and the associated investigations should be accomplished within the normal annual planned outage durations.

Containment Structure Maintenance Costs

The system engineer provided estimated costs for the long-term annual maintenance of the containment structure. These costs are estimated to be between $90,000 and $1.18 million annually. The most likely annual cost is $0.5 million. There are also possible modification costs of between $1.54 million and $3.14 million incurred during the refurbishment outage.

6.1.5 Feed Water System

Feed Water Heater Heat Exchangers

The Gentilly 2 feed water system contains two parallel trains of feed water heat exchangers, each capable of 50 percent of design flow. Each train is made up of one high-pressure heat exchanger with carbon steel tubes, and three low-pressure heat exchangers with stainless steel tubes.

Gentilly 2 did not have a routine inspection program for inspecting the condition of these heat exchangers in the past. One high-pressure and one low-pressure heat exchanger were visually inspected about two years ago. No problems were identified. For the last five years, Gentilly 2 has been performing an overall leak test on the feed water heaters once a year during the yearly planned outage. The draft PIME document has an inspection of one low-pressure feed water heater and one high-pressure heater in 2000 with subsequent inspections of additional heaters in 2003, 2005, 2008, and on into the future.

The draft PIME document also has an item to replace the high-pressure feed water heaters in 2008. The replacement of the high-pressure feed water heaters was suggested based on the plant

19. Draft containment aging report for Gentilly 2 and Point Lepreau — unpublished, AECL, 1997.

being about 25 years old in 2008, and, if the life of the plant is extended for another 25 years, they may have to replace (retube) these heaters. At the current time the heaters are functioning with no problems. However, there have been no detailed measurements of the condition of the tubes in any of the feed water heaters. Until these measurements are completed, there is no real basis for estimating if, or when, retubing of any of the feed water heaters is required.

Deaerator (degasser/condenser)

Early in the plant operation, in 1984, there were problems with the deaerator. Modifications were performed and the deaerator has been operating very well since. Inspections have been performed and no problems have been noted. The oxygen levels in the feedwater that goes into the steam generator have been low, confirming good performance of the deaerator.

Boiler Feed Water Pumps and Extraction Pumps

Gentilly 2 has three 50 percent capacity motor-driven feed water pumps. Early in the station operation there were some problems with the first stage impellers. Modifications were made and the pumps are now performing well.

Probability of a Major Feed Water System Outage

It was recommended previously that the condition of the feed water heater tubes be tested in the near term. Provided that any degradation of the feed water heaters is identified and corrected in a timely manner, we believe that with continued high-quality preventive and predictive maintenance there is a low probability of a major plant outage caused by the feed water system components.

Feed Water System Major Equipment Replacement Costs

The system engineer provided an estimate of $0.5 million to replace one high-pressure feed water heater. Until detailed measurements of the condition of any of the feed water heaters are available, there is no real basis for projecting if and when any major expenditures will be required.

6.1.6 Condenser

Background

The Gentilly 2 condenser has admiralty brass tubes for the main section and stainless steel tubes for the air cooler and impingement areas. The tube sheet material is Muntz metal. The admiralty tubes are nonfouling and the stainless steel tubes are mechanically cleaned during the cold months of the year. The water boxes are internally coated with epoxy coal tar for corrosion and fouling protection. There are four condenser water boxes, two for each of the two low-pressure steam turbines.[20] During the cold winter months, the plant can operate at full load with one condenser water box out of service.

Detailed tube leak inspections of the condenser have been performed periodically starting in 1985.[21] Major inspections covering more than half of the tubes were performed in 1995 and 1997. Some material degradation was noted. As of November 1997, about 5.3 percent of the stainless steel tubes have been plugged and about 0.4 percent of the admiralty brass tubes have been plugged.[22] Based on the plugging history of the condenser, the Gentilly 2 staff has estimated a 95 percent confidence that the condenser will not require replacement or retubing before 2003. The confidence level reduces to 75 percent in 2007 and then decreases rapidly to 50 percent in 2009 and 10 percent by 2011.

Probability of a Major Condenser Outage

It is estimated that the replacement of the condenser will require between 10 and 14 weeks, and we expect that this can be done during a refurbishment outage. This replacement of the condenser will not require any outage time in addition to either the feeder/pressure tube replacement outage or the normal planned outage durations.

Major Condenser Equipment Replacement Costs

An estimate of the costs to replace the condenser was developed for both a replacement with the current admiralty brass tubes and with titanium tubes.[23] If the condenser is retubed with the current admiralty brass tubes, the estimated cost is $4.22 million with a range from $3.59 million to $4.96 million. If the condenser is retubed with titanium tubes, the costs are estimated to be between $7.63 million and $10.56 million with a most likely value of $8.98 million.

The use of titanium tubes has advantages in terms of the lifetime of the tubes, protection from tube failure, and the ability to further enhance the water chemistry to help extend the lifetime of the steam generators. However, titanium condenser tubes have disadvantages in terms of initial cost, OM&A costs, and plant output during the summer months. The selection of the tube material will be made at a later date. For the purpose of our analysis it has been assumed that there is a 50 percent probability that admiralty brass will be selected, and a 50 percent probability that titanium will be selected.

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20. Ingersoll-Rand Company, "Instructions for Maintenance and Operation of Surface Condenser and Auxiliary Equipment," #1666-01-1-MD-A, 42121-501.

21. Correspondence interne, Michel Cantin to Martin Drouin, "Bilan d'inspection du condenseur principal 4210-CD10, 12/2/97.

22. Note interne, Martin Drouin to Claude Sicard, "Duree de vie des tubes du condenseur," 11/26/97.

23. Note interne, Martin Drouin to Claude Sicard, "Cost estimate for the replacement of the tube for the condenser at Gentilly 2," 11/25/97.

Plant Derating because of Condenser Performance

With the current admiralty brass condenser tubes, the plant is required to derate about 10 MWe during the three summer months. With titanium condenser tubes, the equivalent derating would be increased to about 15 MWe to account for the decreased heat transfer.

Additional Operation and Maintenance Costs with Titanium Condenser Tubes

With titanium condenser tubes, the plant would need to add additional staff equivalent to about three people to operate and maintain the on-line tube cleaning system and additional materials. This would increase the annual OM&A costs by about $0.21 million per year.

6.1.7 Equipment Not Treated in the Model

Several systems and components were not quantified in the model.

- primary and secondary system heat exchangers
- main transformers
- heat transport pumps
- emergency water/reheater drain header in steam generators
- emergency core cooling system (modifications addressed as a regulatory input)
- primary and secondary system piping
- fuel handling equipment
- cooling water tunnels (pipes)
- electrical system
- reactivity control units
- motor operated valves
- instrumentation and controls (except DCCs and PDCs).

As described in Section 6.3.3, additional planned outage time and costs may be needed during the final years of station operation.

6.2 REGULATORY INPUTS

There are three reasons to include regulatory inputs in the model. First, the AECB has established a list of outstanding generic action items or unresolved regulatory issues that deal with aspects of the CANDU design. These items are common among all of the CANDU units and many of them may require either additional analyses or modifications to be resolved. Experience has shown that unresolved regulatory issues may require plant modifications for resolution. Second, since licensing of CANDU units takes place every two years, requirements can be imposed as a condition to the license, particularly if life is extended beyond nominal design life. Third, other events occurring in the industry can prompt the AECB to establish new requirements.

We have identified three ways that regulatory issues can cause costs and outage time at Gentilly 2:

- regulatory OM&A cost increases
- backfit costs (capital cost increases)
- additional outage time.

If Hydro Québec decides to pursue life extension for Gentilly 2, some or all of these issues may need to be resolved before a continuing license beyond 30 years of operation can be obtained. The generic and specific action items, along with a number of licensing issues, were reviewed to determine the effect these issues may have on OM&A, backfit, or additional outage time. As part of this assessment, discussions took place with Hydro Québec, NB Power, AECL, and AECB staff. Not all of the issues are discussed herein. We evaluated 21 critical issues; the most important of these is that we expect to have a significant outage time (greater than four months) or costs (greater than $5 million) are included in this report.

The issues causing the most significant costs, derates, and/or outage time are:

- periodic safety review
- probabilistic safety assessment (PSA)
- effects of primary heat transport system (PHTS) aging
- environmental qualification (EQ)
- configuration management
- post-refurbishment licensing
- additional regulatory requirements that are unknown at this time.

Each of these issues is discussed below.

6.2.1 Periodic Safety Review

The practice in Canada is to have an ongoing safety analysis program in support of reactor safety at each utility. This program deals with new issues arising out of assessment of events at operating stations, new analysis in support of other plants or new reactor designs, information on plant aging, review of the Safety Report, and regulatory issues. The Safety Report is updated every three years to reflect new analyses and improved understanding. The effectiveness of the ongoing safety program is reviewed at least every two years as part of the Operating License renewal process. In other parts of the world, analysis is performed as part of the initial licensing. No further analyses is performed for the life of the station. The International Atomic Energy Association (IAEA) is now recommending "periodic safety reviews" where the analysis is redone and the plant is "re-licensed" every 5 to 10 years.

The AECB is reviewing the method of periodic safety reviews to determine whether or not to endorse the concept. Canadian utilities have indicated that an ongoing program makes more sense and is more effective.

Hydro Québec expects the AECB to switch the licensing process to incorporate periodic safety reviews. It is expected that any reanalysis required for CHF-enhanced fuel will be built into the periodic safety review as will any reanalysis required for life extension of Gentilly 2. Thus, we include in the model a cost to complete a 10-year periodic safety review.

6.2.2 Probabilistic Safety Assessment

Gentilly 2 was designed and licensed on the basis of deterministic safety analysis. Probabilistic assessments were also conducted to address design issues.

The AECB is requesting that Hydro Québec perform a probabilistic safety analysis to supplement the deterministic analysis. In addition, the AECB expects the probabilistic analysis to be updated and maintained, with the station being operated accordingly.

Hydro Québec is planning to perform a PSA from 1998 to 2002. The model includes up to $5 million for this effort.

6.2.3 Effects of Primary Heat Transport System Aging

The effects of age have caused a change in the design characteristics of the fuel channels. This has affected the critical heat flux, and several measures are being considered in order to mitigate the impact, including:

- reducing secondary side steam generator pressure
- modifying the regional overpower temperature (ROPT) trip setpoint plateau structure
- introducing a reformed channel power reference distribution
- cleaning of steam generator primary side
- introducing a four-bundle shift fueling scheme for the central channels
- cleaning of the primary heat transport system
- introducing a CHF-enhanced fuel bundle (CANFLEX or 37 element with buttons)
- modifying and possibly providing additional process trip setpoints
- increasing CIGAR measurements to better determine pressure tube creep
- removing (for inspection and analysis) a portion of inlet feeder with orifices
- replacing pressure tubes.

Gentilly 2 has derated as much as 3 percent to address the CHF concerns. During the 1998 outage, some actions were taken to minimize the derating. However, a more aggressive approach may be more cost-effective than derating the station. A new fuel design is being considered. Candidates are either CANFLEX (a new 43-element design) or an enhanced 37-element bundle.

PLGS is currently planning for a demonstration irradiation of 24 CANFLEX bundles in early 1998. CHF water tests results for CANFLEX fuel may be available in 1999. However, CANFLEX or CHF-enhanced fuel will not be available before 2003. For Strategy 2, where the plant operates until 2008 before replacing fuel channels, there may be a benefit to switching to the new fuel design. However, for Strategy 1 we expect the benefit of the new fuel design to be minimal. Regardless, a derate is expected and is included in the model.

If the fuel design is changed to CANFLEX the costs may be as high as $6.5 million; however, if a new fuel design is not installed, the derate could be as high as 10 percent by 2003.

6.2.4 Environmental Qualification

Background

Environmental qualification (EQ) of equipment has been an industry-wide problem. Hydro Québec has started a program to replace instrumentation and electrical components during the 1998 outage. Equipment of concern includes solenoid valves (SV), pressure relief valves (PRV), pressure transmitters (PT), resistive temperature detectors (RTD), local air cooler motors (LAC), and cable.

One of the highest profile EQ issues is PVC cables in containment. Concern has been raised by Ontario Hydro over the last few years that PVC insulation may be susceptible to insulation degradation under harsh environment conditions. Cable insulation research is an ongoing issue in Europe and North America. In the United States, the Nuclear Regulatory Commission (NRC) is presently conducting cable testing at Wyle Laboratories to examine the effect of harsh environment conditions on their type of cables. PVC insulation does not have as good a reputation as other types of insulation used in the United States and Europe; thus, Ontario Hydro has taken a proactive approach in research. In February 1997, AECL issued an official bulletin expressing concern about PVC cables based on the latest research by Ontario Hydro. In late 1997, test results indicated that at least 80 percent of the cable in containment would not require replacement. The test results for the remaining cable in high temperature areas during an accident condition (upper containment) are not available.

The EQ program is not capitalized and is covered under the OM&A budget even though the costs are not budgeted for 1998 and will cause an increase to $2.3 million for 1998 and $3.2 million from 1999 to 2002. To address the issues by 2002, seven to eight staff members are needed full time. Thus, costs of $15.1 million are expected to be required before 2002.

6.2.5 Configuration Management

Background

Because the plant is continuously evolving to adapt to new technologies and regulations, there must be a process of verifying that any changes to the plant's specifications are analyzed and determined to meet both safety and regulatory requirements. The process must also ensure that the design drawings are updated simultaneously with the design changes, so that the drawings reflect the current configuration of the plant. This overall process is known as configuration management.

At Hydro Québec, an effort to update plant documents has been initiated. The initial effort is concentrated on updating drawings and wiring documentation on the special safety systems as those systems are currently reviewed for seismic and EQ requirements versus the configuration (documents and physical). This action will require $2 to 3 million.

Improving this original documentation may be required either before a life extension or in order to be relicensed for an extended period after the 30-year design life of the plant. This would involve producing new drawings and documentation to define the initial configuration.

Hydro Québec will approach this issue methodically, updating the design documentation for the most important systems first and then updating the design documentation for other systems. Eventually, their design will be completely updated.

For the model, we forecast that costs could be as high as $20 million with a most likely case of $15 million.

6.2.6 Post-Refurbishment Licensing

If the plant is refurbished, an extension of the license will be required. Additional costs depend on criteria that the AECB sets at the time of relicensing and may involve many of the issues discussed above. Moreover, if Gentilly 2 adopts a strategy of replacing only a quarter of the core fuel channels at a time, specific safety analysis will be required to assess the various configurations that this will create.

It is difficult to determine the amount of analysis required at this time. For Strategy 2 we modeled a probability of costs being from $2.5 million to $10 million. For Strategy 1, we expect the costs to be higher and they are modeled between $5 million and $12 million.

6.2.7 Additional Regulatory Requirements

In the model, we have assigned a probability that many known generic requirements may be imposed causing additional outage time and/or significant costs.

In the United States, stations have been shut down by the U.S. Nuclear Regulatory Commission (NRC) or have been shut down by the utility management. We found the number of shutdowns was not excessive; however, the length of those shutdowns was extensive.

Even as the regulator (AECB) imposes more requirements, we do not expect that nuclear stations in Canada will experience lengthy shutdowns due to regulatory requirements.

There is, however, a potential for new costs due to regulatory requirements. We have found both in the United States and Canada that an event can cause the regulator to impose unforeseen expenses in the form of plant modification costs. Thus, we include a probability of $10 million (median) in costs due to unknown regulator requirements.

6.3 ROUTINE COSTS

Routine costs include the normal budgeted costs of operating the plant today and in the future without considering the specific equipment and regulatory issues. The routine costs have been divided into the following categories:

- routine annual OM&A costs
- routine annual capital costs
- planned outage costs and durations
- other routine and forced outage durations
- fuel costs
- decommissioning costs
- LLW costs
- irradiated fuel management costs.

A summary of each issue is presented below.

6.3.1 Routine Annual OM&A Costs

These costs include budgeted routine annual OM&A costs for the plant. We identified what costs were routine annual OM&A to ensure that costs are not double counted in the specific equipment and regulatory issues being addressed. The model included the following costs as routine annual OM&A:

- research and development [e.g., COG, WANO (World Association of Nuclear Operators)]

- regulatory fees (we addressed the cost of additional modifications and analyses for each individual issue)

- materials and consumables

- employees and hired labor — all departmental activities
- hired services
- heavy water
- property taxes
- insurance.

Other elements of OM&A costs are addressed in other sections of this report and are not included here; these include the following:

- nuclear fuel
- low and intermediate level waste management
- planned outages
- aging program
- possible additional equipment problems and regulatory issues.

The routine annual OM&A costs were estimated to be between $71 and $79 million. In our results and conclusions section of this report, all elements of the OM&A costs are reported (including the potential of costs from the five areas identified above).

6.3.2 Routine Annual Capital Costs

Routine annual capital costs include additions that are not included in the issues being addressed separately. We did not include the following because they are covered explicitly in the model:

- problems with major equipment, including pressure tube, spacer relocation (SLAR), feeder pipe repairs, and steam generator replacement
- safety issues, including plant modifications that might be required as a result of future regulatory concerns
- storage and disposal of LLW or spent fuel.

Routine annual capital costs are estimated to be between $5.5 million and $12 million with a most likely cost of $8 million per year. Overall capital costs, including the potential of costs in the three areas identified above, are reported in the Results and Conclusions section of this report.

6.3.3 Planned Outage Costs and Durations

Planned outage costs are those costs that are incurred during each individual outage beyond what is already included in other issue costs. We ensure that these costs are not included as part of routine annual OM&A, routine annual capital, or specific (equipment and regulatory) issue costs because these costs are explicitly modeled.

The Gentilly 2 outage planning staff provided estimates of annual planned outage durations for 1997 through 2033. These outage durations are based on the periodic planned maintenance that has historically been performed during the planned outages, and long-term outage input from the system engineers. The outage durations are generally dominated by the critical path times for the following:

- SLAR
- periodic turbine generator inspections
- periodic inspection programs and in-service inspections (ISI)
- steam generator inspections and cleaning.

Adjustments for Long-Term Wear Out

There are many components in the plant that will require repair and replacement as the plant ages, particularly beyond 2008. The outage labor and materials costs and the timing of repairs or replacement of these components cannot be defined at the present time. We have evaluated a number of potentially costly components that seem to be in relatively good condition but could be subject to long-term wear out. These components include:

- primary and secondary system pipes
- primary and secondary system heat exchangers
- main transformers
- electrical system, including breakers, station batteries, and inverters
- heat transport pumps
- fuel handling equipment
- instrumentation and controls.

To account for the long-term wear of these and other plant components, we assumed that the planned outage durations and the material and additional labor costs for the planned outages will be greater. We have applied additional factors of 10 percent, 20 percent, and 30 percent to the long-term planned outage durations and additional labor and materials costs to accommodate the long-term wear-out costs.

6.3.4 Other Routine and Forced Outage Durations

There are three types of events that reduce the output from any plant. These are planned outages, unplanned outages, and deratings (power reductions). Events that have the greatest potential to affect Gentilly 2 are addressed explicitly, including planned outages, long unplanned outages due to major equipment issues, outages due to regulatory concerns, and deratings due to safety limits. These events are discussed in detail in other sections of this report and are all treated explicitly in the model.

Other potential outage events must also be explicitly modeled. These are shorter, unplanned outages due to major equipment, all unplanned outages due to nonmajor equipment, and all deratings not due to safety limits. To project these outages, we looked at the historical impacts of these events at U.S. plants, considered possible trends, and compared Gentilly 2's experience with experiences at U.S. plants.

We developed a short unplanned outage rate [most likely: 2 equivalent full power days (EFPD) per 7,000 hours] and a long unplanned outage rate (12.5 EFPD per 7,000 hours].

6.3.5 Fuel Costs

Fuel costs are treated as a separate issue and include all aspects of fuel such as the costs of uranium, production, and fabrication. Gentilly 2's fuel contracts expire in 2000; however, costs are not expected to rise significantly. What could cause fuel costs to increase is a change to CHF-enhanced or CANFLEX fuel. In our analysis, the amount of fuel used by the reactor is based on the capacity factor utilization. The base costs are $8.06 million for an 80 percent capacity factor. If the plant is shut down or derated, the fuel costs are less. For Strategy 1, we assume there is no benefit to switching to CANFLEX fuel because CANFLEX will not be available until 2003 at the earliest and the outages will begin in 2005. No increase in fabrication costs is modeled. For Strategy 2, we assume that there is an 80 percent chance of some sort of design change to the fuel, which is expected to significantly increase (double) fabrication costs.

6.3.6 Decommissioning Costs

The current Gentilly 2 decommissioning plan was written in 1993. A new revision is expected to be submitted in 1998. We expect cost increases to be indicated by the new revision. The cost for decommissioning is estimated at $344 million (converted to 1998 dollars) in this document.

Over the last 5 to 10 years, there has been much discussion and debate in the nuclear industry regarding decommissioning methodology and the associated costs. Cost estimates have varied greatly between plants, and to date there has been relatively little industry experience with which to benchmark costs. One of the reasons for the variations in estimates is that there are a number of site-specific variables that can significantly affect the decommissioning cost of a given site. These variables include unit sizes, plant type, continued or reuse of the site, operating history, waste disposal options, and the regulatory and political environment.

In general, estimated decommissioning costs in the United States have increased substantially in real terms since 1990. The major reasons for the increases have been increased waste disposal costs, waste volume, and manpower estimates (radiation surveys, waste handling, work in hazardous environments, and regulatory).

We modeled the current decommissioning cost estimate as a minimum, but an increase in costs as the most likely case. The decommissioning cost estimate of $537.9 million was included in the model as a most likely cost.

6.3.7 Low Level Waste (LLW) Costs

Routine LLW costs are included in the OM&A budgets as routine health physics department activities. However, the costs of building and maintaining a new LLW storage facility and of shipping LLW to a remote facility in order to establish a green field at Gentilly 2 are considered separately. With these costs, we also consider intermediate level wastes, including the disposal of resins.

For Strategies 1 and 2, we modeled the costs of additional LLW storage to be between $5.5 and $6.5 million. Because of volume reduction efforts, the LLW storage may not be needed until later. The model assumes a 50 percent probability that the costs will be incurred in 2005 and 50 percent probability that they will be incurred in 2012.

6.3.8 Irradiated Fuel Management (IFM) Costs

There are two separate costs associated with spent fuel. First, Hydro Québec must build and maintain on-site temporary spent fuel storage. Second, the current IFM program assumes construction of a national used fuel disposal centre (UFDC) that would begin accepting used fuel from Gentilly 2 in 2025.

It should be noted that alternative plans being considered include temporary long-term above-ground storage. On March 13, 1998, the Canadian Minister of the Environment issued the findings from the federal panel studying the long-term management of nuclear fuel waste. The panel evaluated the acceptability of AECL's concept to bury nuclear waste deep within the rock of the Canadian Shield. The eight-member panel recommended that the search for a specific site not proceed at the present time. It is expected that a government decision on the panel recommendations will be made later this year.

Funds are currently being accrued for this final disposition of fuel. However, the permanent disposal costs are based on a per-bundle basis for all of the units operating in Canada. The estimated number of bundles to be disposed of is too high, thus underestimating the cost of disposal per bundle.

A great deal of uncertainty exists, not only in Canada but also throughout the world, regarding the ultimate disposition of spent nuclear fuel. Therefore, it is difficult to predict with any accuracy what disposal costs might be. To adequately fund the IFM program, it will be necessary to stay abreast of developments and to evaluate the fund status in light of these developments.

The model includes costs for maintaining spent fuel storage facilities on site as well as shipping spent fuel to a national repository. The most likely costs for interim dry storage onsite through 2025 is estimated at $49.74 million.

7. ECONOMIC INPUTS

To determine the total costs associated with each Gentilly 2 operational strategy, it is necessary to determine the cost of power when Gentilly 2 is not available. Discount rate is another critical input.

7.1 REPLACEMENT POWER COSTS

Values for replacement power were obtained from Hydro Québec's planning staff. Replacement power, or the power that replaces Gentilly 2 when it is unavailable because of maintenance or forced outage, was segmented into the months during the year that the outage will occur.

Planned outages are scheduled when replacement power costs are at a minimum, typically from April to June, but also from September to November. Replacement power costs are higher in July and August, but the most costly times are December to March.

The Hydro Québec staff provided the cost of energy and the cost of capacity. The cost of energy is constant throughout the year, but the cost of capacity was calculated from the marginal value of power by month.

7.2 DISCOUNT RATE

The discount rate was calculated using Hydro Québec's predicted cost of borrowing, which is 7.7 percent and includes a 2.5 percent inflation rate from 2001 to 2005 and a 2.7 percent inflation rate from 2006 to 2015.[24]

8. DESCRIPTION OF THE MODEL

The Nuc-Optima™ model was designed and is operated by Hagler Bailly to evaluate a least cost alternative for operating nuclear power plants. The model is modified for Hydro Québec to compare the economic feasibility of Gentilly 2 for the three operating strategies. For each

24. Hydro Québec Internet, June 1998.

operating strategy, the model computes the total going-forward cost of 635 MW_e of power — the net capacity of Gentilly 2 — for every hour during a fixed time horizon, beginning with 1999 and running to 2033.

Future costs are discounted to account for the time value of money. All costs are in 1998 Canadian dollars to control for the effects of inflation. Costs incurred after plant retirement, such as decommissioning costs, are included in the model. As discussed in Section 7, the cost of replacement power is used during planned, unplanned, and forced outages.

Input variables are represented by probability distributions, and the model includes 1,103 probabilistic input variables. For example, whether the main turbine fails in year 2016 is a probabilistic input variable.

The model has been developed in an Excel-based add-in program called @RISK and uses Monte Carlo simulation to statistically sample from these input probability distributions. Monte Carlo simulation is a technique commonly used to assess potential outcomes from complex systems with a degree of uncertainty.

Each issue is individually modeled; however, the issues are not necessarily independent. Thus, there are several interactions among inputs that must be addressed. First, we ensure that all costs are treated consistently with the same overhead and contingency. Second, we ensure that issues that overlap are dealt with so that there is no double counting. This is most important for OM&A and capital costs because if an issue has been defined as causing costs it typically appears in the plant OM&A or capital budgets.

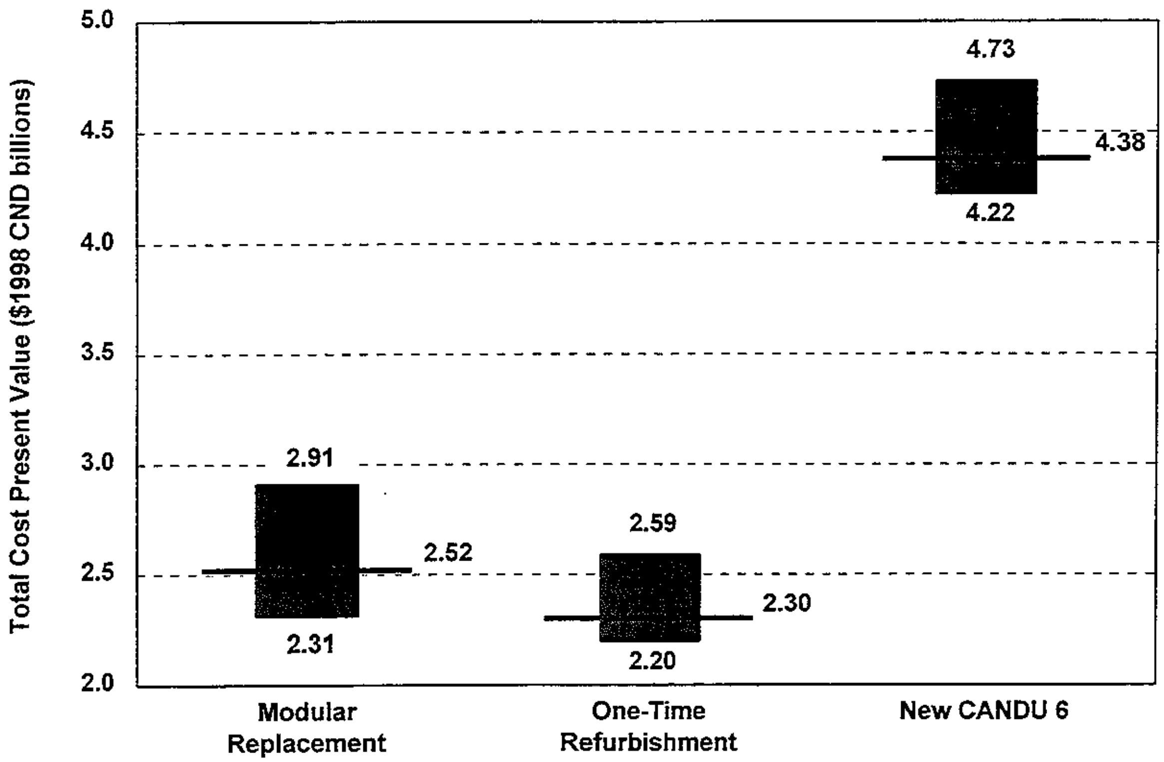
Overlapping of outages caused by specific issues must also be considered. For many of the individual equipment issues, the outage durations already consider the shadowing effects. Shadowing is the amount of outage time that might overlap. For example, a forced outage may be caused by a main turbine failure, and the plant may begin work on a planned outage early as a result. Thus, there are two outages to consider and we must ensure that the time that overlaps the two outages is not double counted. This is the case for the issues that are low probability but could cause a major outage.

Another type of interaction is the variable costs that are tied to the capacity factor. For example, fuel cost predictions are tied to the capacity factor predicted in the model.

9. RESULTS AND CONCLUSIONS

Considering all of the issues discussed in this report, we identify the range of probable costs for each operating strategy. We discount these costs to the present value in 1998 Canadian dollars. Exhibit 9-1 shows the range of probable costs for each operating strategy using the predicted

Exhibit 9-1
Comparison of Gentilly 2 Operational Strategies



replacement power costs as well as the discount rate currently used by Hydro Québec. In addition, this exhibit shows the comparison among the three strategies.

9.1 RESULTS INTERPRETATION

Exhibit 9-1 displays a range of estimated costs as three statistics (median, lowest, and highest cost) for each operating strategy. The median (50th percentile) cost estimate is indicated by the horizontal bar. For example, the median cost estimate for Strategy 1, modular replacement of fuel channels, is $2.52 billion. This means that, in the 1,000 iterations we simulated, the cost associated with this operating strategy is less than $2.52 billion in 500 iterations, and greater than $2.52 billion in the other 500 iterations. In addition to the median estimate for each operating strategy, the cost range predicted by the model is indicated by the vertical bar. For example, for Strategy 1, the highest observed cost among the 1,000 iterations is $2.91 billion, and the lowest observed cost is $2.31 billion. The length of the vertical bar shows the magnitude of uncertainty for each scenario.

The median cost for Strategy 1, modular replacement, is $2.52 billion; the median cost for Strategy 2, one-time refurbishment, is $2.30 billion; and the median cost for Strategy 3, a new CANDU 6, is $4.38 billion.

To show the amount of variability associated with each strategy, we present the results using probability distributions as well. Exhibit 9-2 provides probability distributions of each of the operating strategies.

Exhibit 9-2
Cost Distribution for Three Strategies

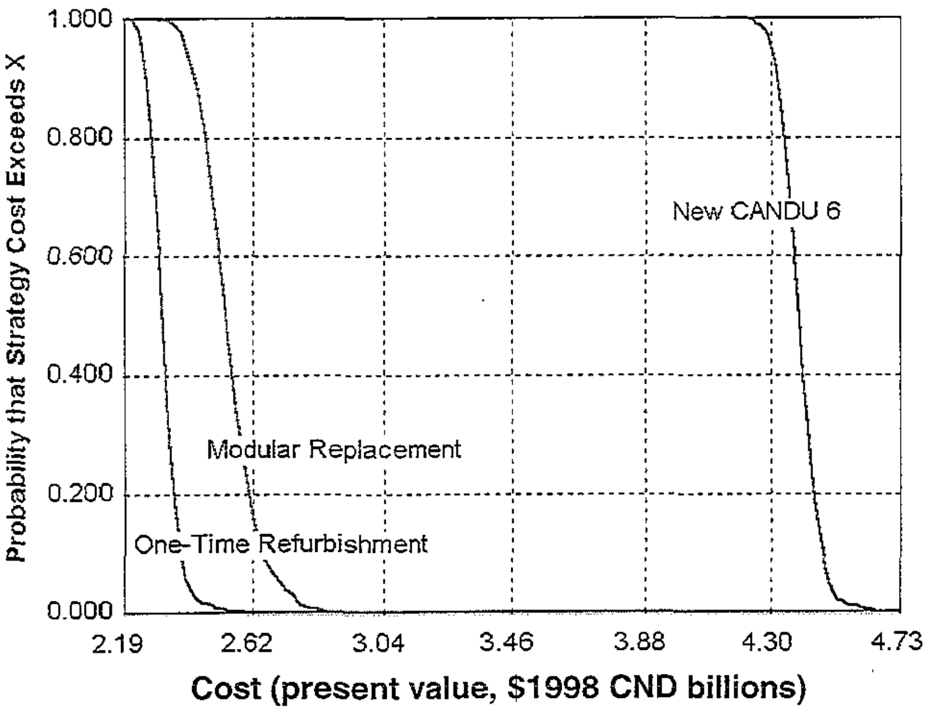


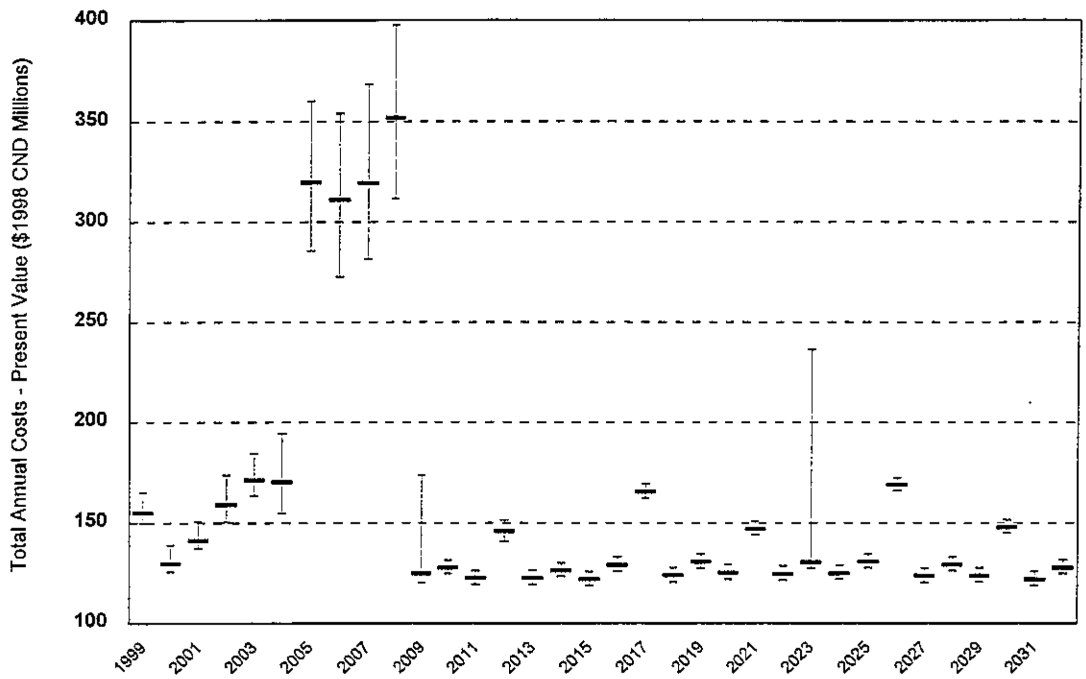
Exhibit 9-2 shows three probability distribution curves, each representing an operating strategy. These curves reveal information about the probability, magnitude, and uncertainty of costs for each operating strategy. The Y-axis shows the probability, and the X-axis shows the cost in billions of Canadian 1998 dollars. Each line represents the least cost at a probability. For example, looking at Strategy 1, modular replacement, there is a 20 percent probability that this will cost at least $2.62 billion and a 10 percent probability that this will cost at least $2.8 billion. At the top of the graph, each operating strategy has a 100 percent probability of being more than $2.2 billion.

Each curve has a least cost and highest cost representing the amount of uncertainty for each operating strategy. Graphically, the uncertainty is represented by the slope of the curve. The more vertical curve represents lower uncertainty. The more horizontal curve represents more uncertainty.

9.2 TOTAL ANNUAL COSTS FOR STRATEGIES 1 AND 2

An important consideration is the annual costs for each strategy. We show the expected annual total costs for Strategy 1 in Exhibit 9-3 and the total costs for Strategy 2 in Exhibit 9-4.

Exhibit 9-3
All-In Costs of Modular Replacement (Strategy 1)



The total annual costs are not very different between the two strategies aside from the costs associated with the refurbishment outage costs.

9.3 ANNUAL CAPACITY FACTOR FOR STRATEGIES 1 AND 2

Annual capacity factor is also important. We show the expected annual capacity factor for Strategy 1 in Exhibit 9-5 and the annual capacity factor for Strategy 2 in Exhibit 9-6.

Capacity factor varies significantly from 2005 to 2008. Also before that time, the capacity factor for Strategy 1 is lower because we assume that CHF-enhanced fuel is not used and the station must derate without a new fuel design.

Exhibit 9-4
All-In Costs of One-Time Refurbishment (Strategy 2)

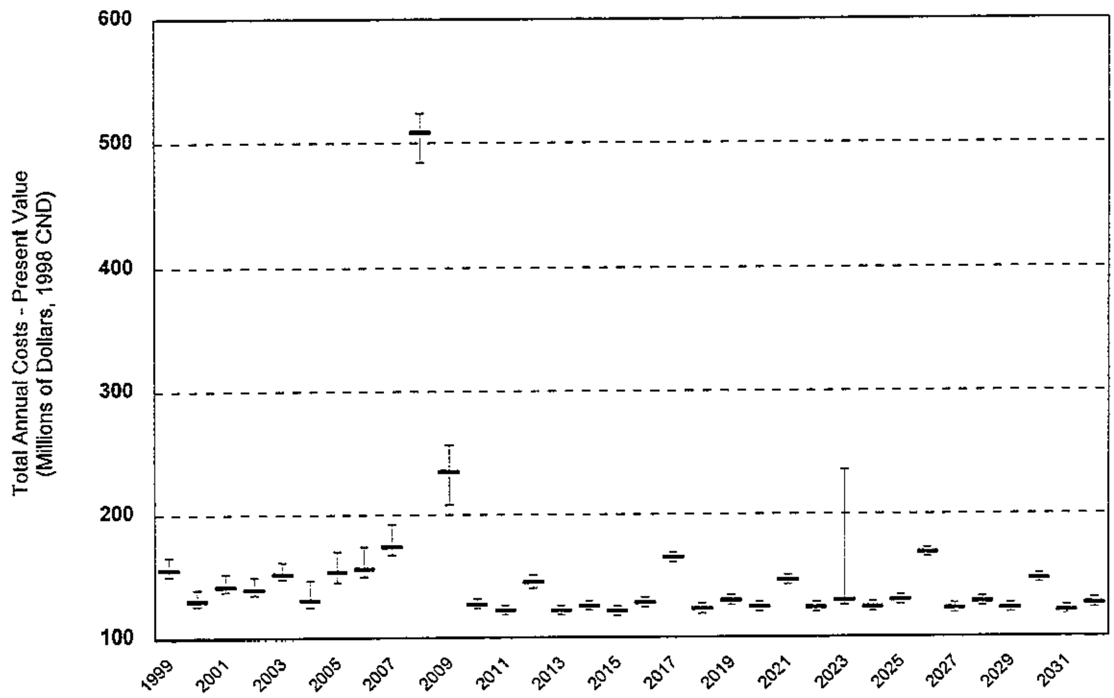


Exhibit 9-5
Capacity Factor for Modular Replacement (Strategy 1)

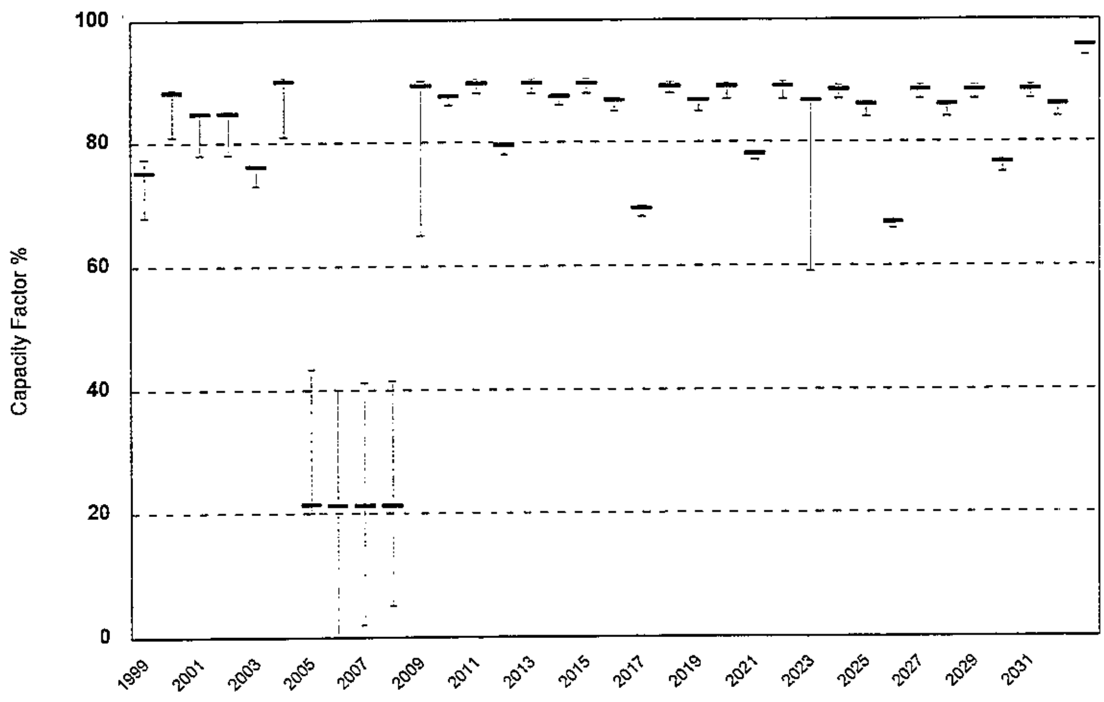
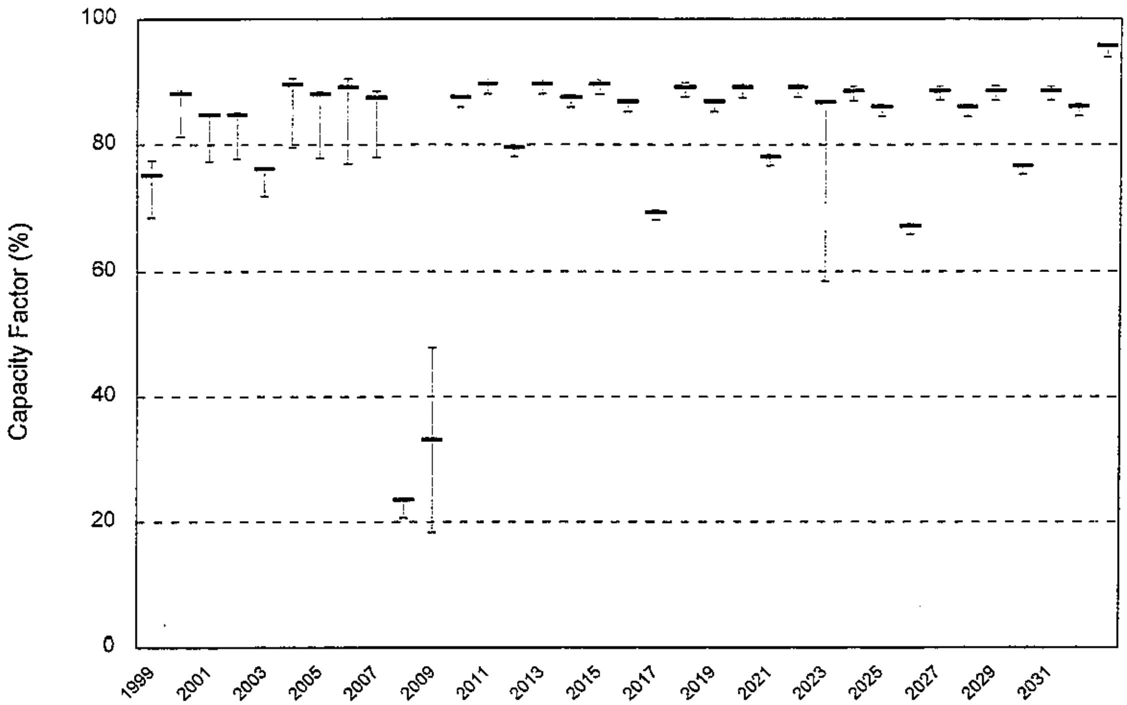


Exhibit 9-6
Capacity Factor for One-Time Refurbishment (Strategy 2)



9.4 LEVELIZED COST FOR ONE-TIME REFURBISHMENT (STRATEGY 2)

We estimated the cost per MWh for the one-time refurbishment outage strategy. The cost of \$27.7 per MWh was calculated and does not include replacement power costs. However, there are many caveats associated with this cost, making it difficult to compare this value to other generating sources.

Developing a present value cost as presented in this report for the three strategies is relatively straightforward. Converting total dollars into a cost per MWh is more difficult. Both costs and amount of generation vary annually. Costs can be handled by levelizing the costs and converting them into constant dollars. This assumes that costs and generation do not vary over time; however, for Gentilly 2 both costs and generation vary. The levelized costs assume no time preference for generation. MWh are discounted at zero percent, hence, projected annual capacity factors that vary from the projected average do not matter.

Another problem can result from comparing this or any cost per MWh value with other generating resources. The validity of the estimated cost of \$27.7 per MWh for Gentilly 2 electric production hinges on the assumptions discussed above. Other problems can result from comparing this or any cost per MWh value with other generation resources.

First, the generating resources that are compared should have equal capacities and lifetimes. If not, then present value costs for different resources are difficult to compare directly. Using levelized costs to compare resources implies that when each resource's useful economic lifespan is over, a new and identical resource is used to generate electricity.

Second, the resources that are compared should have similar risk profiles. Outage rates, future costs, and other uncertainties should be similar for the different resources.

9.5 CONCLUSIONS

The least-cost alternative is the one-time replacement of the fuel channels (Strategy 2). Even though this option does not fully meet the objectives of Hydro Québec because a one-time refurbishment outage is expected to last from 457 to 564 days, including replacement of the calandria tubes, the costs are considerably lower. This was the expected outcome of this project. What is more important is the difference in costs between the strategies. The modular replacement (Strategy 1) is forecast to be $221 million more than the one-time refurbishment. This has two components. First, although there are some savings in replacement power costs with modular replacement, the overall outage duration required overshadows this savings. Second, the costs of conducting the modular outages are expected to be at least $90 million more that the one-time refurbishment outage.

A new CANDU 6 station (Strategy 3) is forecast to be $2.08 billion more than the one-time refurbishment. There is also high uncertainty associated with building, licensing, and commissioning a new CANDU 6 station and thus the range of costs are higher.

Another important consideration for Hydro Québec concerns the feasibility of Strategy 1 and the ability to meet Hydro Québec's objectives. With today's technology, the modular replacement does not meet the objective of completing the four annual outages in less than eight months. We assume that the outage duration could be reduced, but further improvements will be needed to pursue this operating strategy. It is currently not feasible.

The total amount of time the station will be shut down for a modular refurbishment is from 880 to 1,200 days. In addition, the range of uncertainty and risk is greater with the modular approach. There is the 25 percent possibility that each outage will last for 12 months. The lost market opportunity is not quantified thus making the modular approach even less attractive.

To make this approach feasible, a significant effort must be made to develop the process and tooling. This effort must begin immediately if Hydro Québec decides to pursue this option.

Planning and scheduling for any of the three options is critical. AECL has stated that they need four years to plan a refurbishment outage. If Strategy 1 is chosen, then work would be expected to begin in 2005. Thus, planning should begin in 2001 at the latest. Considering the feasibility issues that must be addressed if this option is chosen, it is prudent to begin as soon as possible.

Time is very much of the essence. For Strategy 2, planning must begin by 2004 to replace fuel channels in 2008. For Strategy 3, to ensure that Gentilly 3 is ready and available for operation by 2008, work would need to begin immediately. Thus, Strategy 2 provides the most time before costs are incurred and a decision needs to be made.

9.6 RECOMMENDATIONS

9.6.1 Plant Refurbishment Options

If the plant is to be refurbished we strongly recommend the fuel channels be replaced at one time (Strategy 2). Improvements may be made to the cost and schedule if Hydro Québec negotiates with AECL and collaborates with NB Power. We strongly recommend coordinating outage personnel and tooling with NB Power and possibly Ontario Hydro.

If Strategy 2 is pursued, we recommend:

- begin planning in the near term
- develop associated costs with Gentilly 2 staff, AECL, and COG
- negotiate a contract with AECL to further develop tooling and processes.

9.6.2 Plant Material Condition

The following is a brief summary of the recommendations made in this report. These pertain to the decision to continue operating the station.

- Monitor the deuterium pickup rate closely in the pressure tubes.
- Monitor the feeder thinning issue closely. Determine if pH changes in the PHTS reduce the feeder thinning rate.
- Evaluate CANFLEX or CHF-enhanced fuels to determine if these alternative fuels may prevent the need to derate before the pressure tubes are replaced.
- Conduct a 100 percent eddy current test in the steam generators before the refurbishment planning stage. It may be more cost effective to replace the steam generators during the one-time refurbishment than to replace them at a later date.
- The feedwater system and the condenser appear to be in good condition; however, eddy current testing will provide indication of the continued condition of these components.
- Develop a regulatory plan to address the Unresolved Generic Action Items with the AECB.

- Monitor the containment concrete issue.
- Collaborate with the rest of the CANDU 6 industry in monitoring and resolving generic industry problems.
- Explore areas where the plant may be vulnerable to significant unknown equipment problems.