Canadian Energy Research Institute

Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario

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EXECUTIVE SUMMARY & CONCLUSIONS

This report provides a comparison of the lifetime cost of constructing, operating and decommissioning new generation suitable for supplying baseload power by early in the next decade. New baseload generation options in Ontario are nuclear, coal-fired steam turbines or combined cycle gas turbines (CCGT). Nuclear and coal-fired units are characterised by high capital costs and low operating costs. As such, they are candidates for baseload operation only. Gas-fired generation is characterised by lower capital costs and higher operating costs and thus may meet the requirements for operation as peaking and/or baseload generation.

The comparison of baseload generating technologies is made by reference to the estimated levelised unit electricity cost (LUEC). The LUEC can be thought of as a 'supply cost', where the unit cost is the price needed to recover all costs over the period. It is determined by finding the price that sets the sum of all future discounted cash flows (net present value, or NPV) to zero. It can also be thought of as representing the constant real wholesale price of electricity that meets the financing cost, debt repayment, income tax and cash flow constraints associated with the construction operation and decommissioning of a generating plant.[1]

Levelised unit cost comparisons are usually made with different sets of financing assumptions. This report considers two base cases, which we describe as 'merchant' and 'public' financing. The term 'merchant plant' is used to refer to ones that are built and operated by private investors. These investors pay for their capital through debt and by raising equity, and thus pay return on equity and interest on debt throughout their lifetime. These projects include income taxes, both provincial and federal. Publicly financed projects typically are not subject to income taxes or to the same constraints on raising finance through issuing debt and equity. However, they are constrained to provide a rate of return.

The rate of return required for projects is subject to some uncertainty. For a merchant project the higher the perceived risk the higher the required return. Publicly financed projects may be evaluated on the basis of a given discount rate or may be able to access funds at lower rates, but the risk of cost overruns is implicitly borne by the taxpayer. There is a third possibility, a public/private partnership. A number of partnership arrangements are possible, for example, public financing of construction and leasing to private owners for operation. All partnership arrangements represent a sharing of risk between the public and private sector. Public/private partnership may provide an attractive model for building new generation in Ontario.

This report considers each of the generation options under both merchant and public financing. The base case merchant financing scenario is consistent with one where risk is relatively low, and consequently the real return on equity required by private investors is 12%. We believe a comparison between merchant and public financing to be important in that it shows the effect of taxes and financing assumptions on the economics of a generation project. Since the pure

1 Details of the modelling framework used to estimate the levelised unit cost are contained in Appendix D.

economic assessment of projects does not normally consider financing or tax costs, these being transfer payments not essential to the project itself, the public financing version of our assessments can be interpreted as the underlying economics of different technologies. This report does not include a detailed modelling of financing arrangements that could occur under a public/private partnership. However, we do consider how the cost of generation options compares under a wide range of illustrative assumptions on the required return on equity, debt and the debt/equity ratio.

Baseload Generation Options for Ontario

In this report we have examined four baseload generation technologies under a range of possible assumptions regarding capital costs, operating costs and fuel costs. These technologies are:

- Scrubbed coal-fired generating plant with a net capacity of 500 MW with a fuel cost based on the cost of coal suitable for electric power generation in Ontario;
- Combined cycle gas turbine (CCGT) generating plant with a net capacity of 580 MW with a fuel cost based on the estimated cost of gas at Dawn, Ontario;
- Twin ACR-700 nuclear reactor with a net capacity of 1406 MW. Indicative costs for this new technology are considered for a 'first of a kind' and 'nth of a kind' deployment; and
- Twin CANDU 6 nuclear reactor with a net capacity of 1346 MW.

The size and characteristics of the coal and gas generation options are based on a review of publicly available sources. The characteristics of the nuclear options are based on information received from Atomic Energy Canada Limited and include estimates of costs associated with spent fuel and decommissioning. For all options there is some uncertainty about future operating characteristics, fuel costs, and government policy with respect to emissions and on exact specifications of technologies deployed. For this reason, we have considered a large number of sensitivities to examine how the technologies compare under different circumstances.[2]

Refurbishment of existing nuclear units is another option for baseload supply. Refurbishment may be particularly attractive in that it could be completed more rapidly than the construction of new plant. In the absence of detailed data concerning the refurbishment of nuclear plants in Ontario, this report ignores this option. New large hydropower developments could also act as a potential supply of baseload generation for Ontario. However, the number of sites for new large hydro development in Ontario is limited and consequently this option has not been considered in this report.

Other new generating options are not considered either because they are primarily suited to use as a peaking plant or because there is uncertainty as to when the technology could be deployed.

[2] Detailed discussion of data sources and assumptions regarding the different technologies, as well as financing assumptions, are contained Appendices A, B and C.

For example, there is uncertainty concerning the possible deployment of an integrated coal gasification combined cycle (IGCC) plant.

Key Results

The key findings of the report are:

- merchant financed plants have higher levelised costs than public financed plants. The difference is largest for nuclear units, which are most capital intensive and consequently rely most heavily on debt financing. However, while the LUEC appears to be lower under public financing, all of the risk associated with the construction and operation is implicitly borne by the taxpayer. For this reason, comparisons between merchant and public financing should be interpreted with care;
- in the public financing scenarios we have conservatively selected a real discount rate of 8 percent and also included a sensitivity analysis assuming a discount rate between 6 and 12 percent. We note that lowering the discount rate improves the relative competitiveness of the capital intensive generation options (coal and, in particular, nuclear generation);
- in merchant financing scenarios capital intensive technologies compare more favourably where lower returns are required;
- gas-fired generation for baseload supply looks unattractive in nearly all scenarios due to forecast increases in the price of natural gas;
- coal-fired generation has the lowest levelised unit electricity cost if the potential costs of CO_2 emissions are <u>not included;</u>
- with potential CO_2 emissions costs of $15 per tonne included, the twin ACR-700 nuclear reactor is either the least-cost generating option or competitive with coal-fired generation depending on the assumptions made about financing;
- the costs included in the report are for deployment of new ACR-700 technology ('first of a kind' deployment). The cost savings and reduction in construction time for 'nth of a kind' deployment indicate a levelised unit cost competitive with coal even in the absence of CO_2 emission costs;
- the levelised unit electricity cost of CANDU 6 nuclear reactors is significantly higher than that for the twin ACR-700 reactor, even when compared to the 'first of a kind' cost for the ACR-700;
- under public financing scenarios the twin CANDU 6 nuclear reactor is competitive with gas-fired generation and under some scenarios is competitive with coal-fired generation. Under merchant financing assumptions the twin CANDU 6 nuclear reactor appears to be a much less attractive option; and
- the LUECs of coal and nuclear options are relatively robust (change little) in response to changes in the price of coal or uranium. The LUEC of gas-fired generation is very sensitive to changes in the fuel price.

Conclusions

In a world of sustained high natural gas prices, even highly efficient combined cycle gas turbine (CCGT) plant is not, from the perspective of levelised unit electricity cost, an attractive option for baseload generation. However, gas-fired generation for baseload enjoys two advantages over coal and nuclear options that are not directly addressed in this report. First, the construction time is significantly lower, indicating gas-fired generation could meet the need for new baseload more quickly than coal or nuclear options. Second, the relatively low capital cost for gas-fired generation may mean that despite the high LUEC some private investors would still find this an attractive option. Finally, the conclusion that gas-fired generation is unattractive does not necessarily extend to continued development of gas-fired generation as peaking plant.

In the majority of scenarios considered, coal-fired generation appears to be the most attractive option from the perspective of lowest levelised unit electricity cost. This conclusion is altered when emissions costs of $15 per tonne of carbon dioxide are included. While taxes of this type on carbon emissions are not in place in Ontario, there is significant concern over the emissions of new and existing coal-fired generation and this may make new coal-fired generation unattractive.

In this report we have considered two nuclear options. One, the twin ACR-700, represents the deployment of new technology. Our estimates indicate that, under both public and merchant financing scenarios, this technology appears to be competitive (results in a similar LUEC) with coal generation across a large number of scenarios. The second technology, the twin CANDU 6 reactor, represents the deployment of existing technology. Under merchant financing, the high capital costs associated with the CANDU 6 make it unattractive in comparison to both coal and the ACR-700 units. However, the cost comparisons are much more favourable under assumptions of public financing, particularly at lower discount rates. Under public financing the selection of nuclear technologies is a choice between a new technology with lower costs and higher uncertainty, and existing technology with higher costs but lower uncertainty.

The relative competitiveness of different technologies, judged from the perspective of lowest LUEC, is also a function of the costs and form of financing ultimately available to build different options. Capital intensive technologies compare more favourably where lower returns are required. This would suggest the extent to which long-term contracting and public/private partnerships are available may be critical in determining the eventual choice of baseload technology in Ontario.

Determining the best baseload generation options in Ontario is without doubt a difficult task. The levelised unit electricity cost presents a useful method of comparison between different technologies. It is especially useful in examining the impact on relative costs under different sets of assumptions regarding fuel prices, operating characteristics and financing assumptions. However, LUEC provides only a partial answer to the preferred technology for new baseload generation. For example, it does not address exactly when capacity is needed or where quantification based on financial costs fails to account adequately for some factors.

CHAPTER 1: INTRODUCTION

Generation supply systems are made up of a mix of technologies and fuel types that collectively provide an economic supply of power to meet system demands. A common distinction between generating units is whether they are designed to supply baseload or act as peaking units. A baseload unit is typically one that is operated to meet part of the minimum load of a power system and consequently is one that produces electricity both continuously and at a constant rate. In contrast, peaking units are ones designed to run intermittently in order to meet higher than normal demands during daily, weekly or seasonal peaks.

This report provides a lifetime cost comparison of constructing, operating and decommissioning new generation suitable for supplying baseload power by early in the next decade. New baseload generation options in Ontario are nuclear, new scrubbed coal plant or combined cycle gas turbines (CCGT). Nuclear and coal-fired units are characterised by high capital costs and low operating costs. As such, they are candidates for baseload operation only. Gas-fired generation is characterised by lower capital costs and higher operating costs and thus may be a candidate for operation as peaking and/or baseload generation. The analysis includes costs of gaseous emissions from generating units using fossil fuels and the cost of spent nuclear fuel disposal and storage.

Refurbishment of existing nuclear units is another option for baseload supply. Refurbishment may be particularly attractive in that it could be completed more rapidly than the construction of new plant. In the absence of detailed data concerning the refurbishment of nuclear plants in Ontario, this report ignores this option. New large hydropower developments could also act as a potential supply of baseload generation for Ontario. However, the number of sites for new large hydro development in Ontario is limited and consequently this option has not been considered in this report.[3] Future baseload options are likely to include integrated coal gasification combined cycle (IGCC) plants.

Other possible generating options rely on technologies that utilize renewable energy, such as wind turbines and small hydro developments. Renewable technologies may suffer from output that is intermittent and unpredictable. Therefore, they are not usually considered as baseload alternatives. Renewable options may have an important role to play in supplementing (and complementing) generation from others sources, but this role is beyond the scope of this study, which compares baseload options only.

The backdrop of the analysis is the assumption that the operation of generating units required to provide intermediate and peaking service will be similar under all baseload alternatives considered. As such, they can be ignored for the purposes of comparing baseload alternatives.

3 Hydropower could also be supplied from new developments in neighbouring provinces, such as at Conawopa on the Nelson River in Manitoba.

In this report, comparisons of baseload generation are made by estimating the levelised unit electricity cost (LUEC). The LUEC of power is the constant real wholesale price of electricity that meets the financing cost, debt repayment, income tax and associated cash flow constraints associated with the construction, operation and decommissioning of a generating plant. The levelised cost can also be thought of as a ‘supply cost’, whereas the unit cost is the price needed to set the sum of all future discounted cash flows (net present value, or NPV) to zero. Cash flows are made up of costs and revenues. Costs include capital expenditures, operating and maintenance costs, fuel costs, and any taxes and decommissioning costs. The revenue stream comes from the sale of electricity, at the calculated LUEC. The discount rate is the internal rate of return of the annual project cash flows.

Levelised unit cost comparisons are usually made under one of two sets of financing assumptions – either ‘merchant’ or ‘public’ financing. Merchant plants are those built and operated by private investors. These investors pay for their capital through debt and by raising equity, and thus pay return on equity and interest on debt throughout their lifetime. These projects must also pay income taxes, both provincial and federal. Publicly financed projects typically are not subject to income taxes or the same constraints on raising finance through issuing debt and equity. However, they are constrained to provide a rate of return. In Ontario, a third option is also possible, whereby financing is through a public/private partnership. Under such an arrangement public financing could be used for construction of a merchant plant that would then be leased over a long period to private operators. A number of other public/private partnership arrangements are also possible.

In this report we consider all generating options under both merchant and public financing. We believe a comparison between merchant and public financing to be important in that it shows the effect of taxes and financing assumptions on the economics of a generation project. Public financing can thus be thought of as an assessment of the underlying economics of different technologies.

The consideration of both financing options is also important since new coal and gas-fired generation projects would likely be privately owned. In the past, nuclear generation has typically been subject to public rather than merchant financing, although it is unclear to what extent it will continue to be so in the future.

It is important to recognize that an analysis based on levelised unit electricity cost, while providing a means for comparison for different generating options, does not answer some questions pertinent to the Ontario situation. For example, it does not indicate how many new plants will need to be constructed or whether there are suitable locations (with adequate transmission) to construct different options. Some other externalities, financial risks and short-term price volatility are also hard to capture in the LUEC analysis.

The LUEC method of comparison does, however, allow a large range of uncertainties over capital costs, operating costs and other characteristics to be examined. Consideration of these options allows for comparisons of sensitivities. For this reason, we have considered a large range of sensitivities to illustrate the robustness of results to changes in the input assumptions. Key examples included in our analysis concern the impact of carbon dioxide (CO_2) emission costs on coal and gas-fired generation and capital costs associated with the first deployment of ACR-700 nuclear technology (as opposed to 'nth of a kind' deployment).

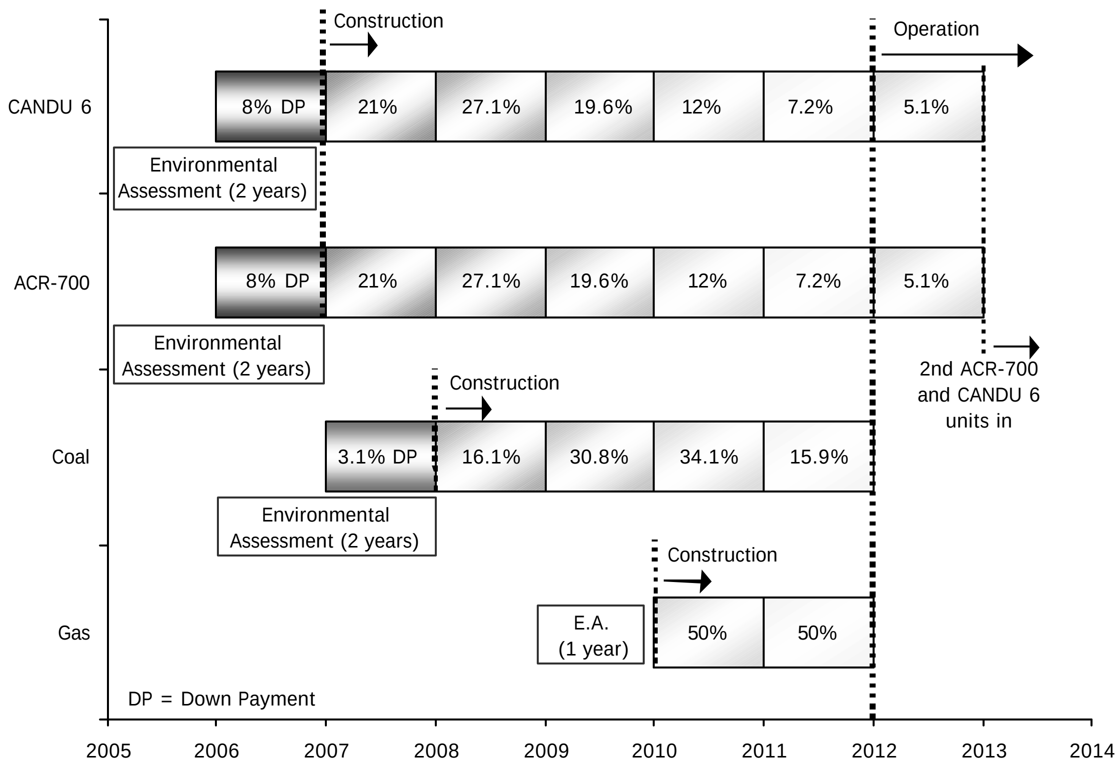
The rest of this report comprises the following chapters. In **Chapter 2** we present a brief description of the base case and sensitivities we have considered. More details on the reasoning behind the selection of base case, sensitivities and a review of alternate data sources are contained in the appendices. **Chapter 3** summarizes the results for our base case comparisons. **Chapter 4** examines the illustrative sensitivities in more detail. **Conclusions** to this report are contained in the executive summary. The appendices to this report also include a detailed description of CERI's LUEC model used in the preparation of this report, a glossary of key terms and a bibliography.

CHAPTER 2: DESCRIPTION OF THE BASE CASE AND SENSITIVITY CASES

2.1. Environmental Assessment, Construction and Date of Operation

The time frames for each of our four generating options are shown in Figure 2.1 below. Each project begins with an environmental assessment phase, estimated at two years for nuclear or coal and one year for gas-fired generation. For both nuclear and coal options we have assumed a down payment is required in the year prior to construction. Both nuclear options are twin units, with the second reactor being completed approximately one year after the first.[4] Also shown in Figure 2.1 below shows the percent of project cash flow expended during each year of construction.

Figure 2.1: Project cash flows and scheduling



Assuming environmental assessment began by 2005, all generation options could be in operation as early as 2012. Coal and gas-fired options require a shorter construction and assessment period. Note that in order to provide an appropriate LUEC comparison all plants are assumed to start operation in the same year. Consequently, LUEC analysis does not account for any potential benefit that particular technologies may present by being able to enter service at an earlier date.

4 The assumed construction time for the ACR-700 is based on the estimated time for a 'first of a kind' unit. Additional units are likely to have a shorter construction time.

The length of time of construction has a major influence on LUEC estimation. This is because cash flows are estimated on a net present value basis (effectively giving the negative cash flows in the early years a greater impact on overall cost). In the case of merchant financing, interest on debt also accumulates during the construction period.

2.2. Base Case Assumptions

The four base cases (one each for coal, gas, ACR-700 and CANDU 6) are built on data collected by CERI.

- *Fuel prices* play an important role in the operating costs of generating electricity, especially for natural gas-fired plants. While capital and other operating costs may be similar across Canada, fuel costs vary widely. Consequently, we made fuel price assumptions specific to Ontario. A detailed explanation of our assumptions regarding the price of uranium, coal and natural gas is given in Appendix A.

- *Capital costs, operating costs and operating characteristics* for each generating option are presented in Appendix B and summarized in Tables B.1, B.2 and B.3.

- *Financial assumptions* are explained in Appendix C.

Table 2.1 provides a summary of the assumptions made for each of the four base cases. The net capacity is 500 MW for coal, 580 MW for gas, 1406 MW for a set of twin ACR-700 units and 1346 MW for twin CANDU 6 units. Fuel costs and other variable operating and maintenance (O&M) costs are derived from net output, that is, net capacity multiplied by the capacity factor at which the plants are assumed to operate. It can be seen that coal and nuclear units have high initial capital costs, but lower fuel operating costs than gas-fired generation.

The base case assumes each generating option would operate for a period of 30 years. A realistic operational life for gas-fired units may be considerably less than this (15 to 20 years), whereas coal and nuclear options could be in operation for 40 years. However, LUEC comparisons need to be made over a consistent time period, i.e. each option starts and stops generating power at the same time. Consequently, the base case assumes each generating option would operate for a period of 30 years, and sensitivities consider operating lifetimes of 20 and 40 years. In the case of nuclear options beyond 30 years, we have included the costs of pressure tube replacement. For non-nuclear options no refurbishment costs are included.

All generation options must pay decommissioning costs after the cessation of operations. For nuclear projects, where decommissioning costs are relatively large, it is assumed that a decommissioning fund is established at the start of operations in which the payments are expensed each year in order to pay decommissioning at the end of the project’s operations. The decommissioning costs for coal and gas options are relatively small and consequently we have assumed no decommissioning costs for either of these options.

In the base case the heat rate for the scrubbed coal unit is set to 9000 Btu per kilowatt-hour. The heat rate for the combined cycle gas-fired unit is 7000 Btu per kilowatt-hour. The heat rates are used in determining the fuel costs per megawatt-hour produced (fuel costs multiplied with the appropriate heat rate ratios), as well as the emissions produced (amount of fuel used to produce a unit of electricity is based on the heat rate). The nuclear units' heat rates are not needed for any of the LUEC calculations. The fuel costs for these units are expressed in dollars per megawatt-hour, and there are no potential costs relating to CO_2 emissions that need to be estimated.

For each technology we also assume a capacity factor of 90 percent, or in other words the generating plant is assumed to produce 90 percent of the energy it would produce if it were to be run continuously at full power.[5] Capacity factors of 90 percent or higher are not uncommon in the operation of nuclear plants and capacity factors in excess of this have been experienced even in aging nuclear reactors in the U.S.[6] The twin ACR-700 reactor is designed to have a capacity factor in excess of this level.

In practice, capacity factors for gas plants may be considerably lower than 90 percent. However, lower capacity factors for gas-fired plants designed even for baseload provision are partly a consequence of higher fuel costs, meaning that once in operation these plants are less likely to run continuously.[7] As a result, historical capacity factors may not be a good indicator of the appropriate capacity factors for use in LUEC estimation. In this report we make the simple assumption that the capacity factor in the base case is 90 percent, supplemented with sensitivities at 85 and 95 percent.

Sensitivity tests are included to cover uncertainty (such as capital and fuel costs), to evaluate the impact of CO_2 emission costs and to estimate the effect of improving technology (such as lower heat rates and different capacity factors). Operational lifetimes of 20 and 40 years are included for all cases. The sensitivity tests are listed in the bottom portion of Table 2.1. Note that for each sensitivity listed, both public and merchant financing cases are tested.

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5 Defined as 'the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period'. See Appendix F.

6 Recent statistics for the U.S. indicate that capacity factors above 90% are not uncommon (see http://www.nei.org/).

7 Higher fuel costs mean that there are higher avoidable costs. Hence when wholesale electricity prices are lower than fuel cost, it may be better for gas-fired generation to choose not to run.

Table 2.1: Base case and sensitivity summaries (all currency data in 2003 C$)

Variable	Coal	Natural Gas	Nuclear Twin ACR-700	Nuclear Twin CANDU 6
Station Capacity Gross			1506 MW	1456 MW
Net	500 MW	580 MW	1406 MW	1346 MW
Plant Cost	$1,600/kW$_{net}$ *($800 million)*	$711/kW$_{net}$ *($412 million)*	$2,347/kW$_{net}$ *($3,300 million)*	$2,972/kW$_{net}$ *($4,000 million)*
Operating Life	30 years	30 years	30 years	30 years
Project Schedule	4 years	2 years	6 years	6 years
Project Cash Flow				
(down payment) Year 0	3.1%	0.0%	8.0%	8.0%
Year 1	16.1%	50.0%	21.0%	21.0%
Year 2	30.8%	50.0%	27.1%	27.1%
Year 3	34.1%		19.6%	19.6%
Year 4	15.9%		12.0%	12.0%
Year 5			7.2%	7.2%
Year 6			5.1% (in op'n)	5.1% (in op'n)
Production Costs				
Fixed O&M	$36.91/kW/yr	$15.38/kW/yr	$10.85/net MW.h/yr	$12.90/net MW.h/yr
Variable	$4.62/MW.h/yr	$3.07/MW.h/yr	$0/MW.h/yr	$0/MW.h/yr
On-going Capital Expenditure	$0	$0	$0	$0
Decommissioning Cost	$0	$0	$8M per year	$11.8M per year
Heat Rate	9000 Btu/kW.h	7000 Btu/kW.h		
Capacity Factor	90%	90%	90%	90%
Fuel Costs	$1.90/GJ level	$6.47/Mcf (in 2005)	$4.00 / net MW.h	$2.30 / net MW.h
real increase	none	1.8% real/yr until 2025	none	none
Spent Fuel Cost	$0	$0	$1.45 / net MW.h	$1.45 / net MW.h
Sensitivities				
Capacity Factor	85% 95%	85% 95%	85% 95%	85% 95%
Plant Cost	$1,500/kW $1,700/kW	$915/kW		
Heat Rate	8,500 Btu/kW.h	6,350 Btu/kW.h		
Fuel Costs	+0.5% real / year -0.5% real / year	+0.8% real / year	+$0.50 level -$0.50 level	+$0.50 level -$0.50 level
Operating Life	20, 40 years	20, 40 years	20, 40 years	20,40 years
CO_2 Emission Costs	$15/t	$15/t		

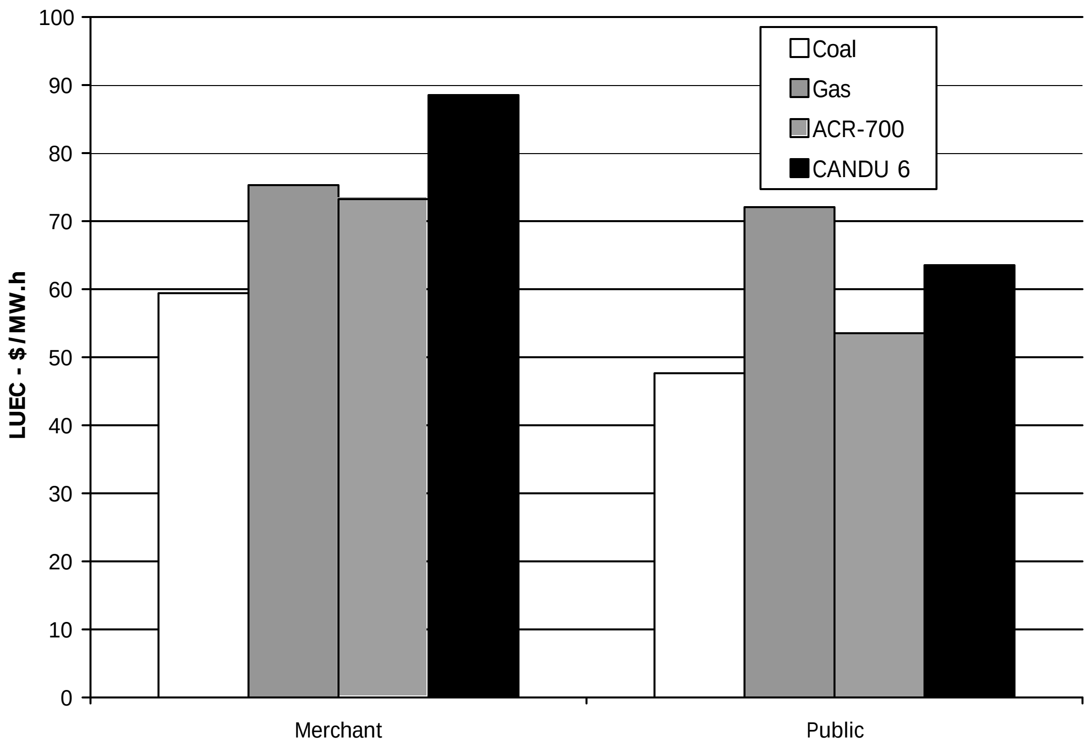
We have assumed that merchant financing requires a 12 percent real rate of return on equity and an 8 percent real rate of return on debt. The debt to equity ratio is set at 50 percent, and the debt life is 20 years. Straight-line depreciation that lasts over the lifetime of the project is assumed. The inflation rate, used to convert real dollar cash flows into nominal dollar figures for tax calculations, is set to 2 percent for all generating types. The income tax rate is 30 percent (federal and regional). Sensitivities that examine the impact of changing assumptions regarding the cost of debt, equity and the debt/equity ratio are considered in Section 4.7.1.

Under public financing assumptions we assume a real discount rate of 8 percent. We note that there remains uncertainty over the correct discount rate for evaluation of public projects and consequently consider the impact of different discount rates in Section 4.7.2.

CHAPTER 3: LUEC ANALYSIS OF THE BASE CASES

The bar chart shown in Figure 3.1 illustrates the base case results for both the merchant and public financing case for all four generating technologies.

Figure 3.1: Base case LUEC results



In our base case under merchant financing, pulverized coal has the lowest levelised unit cost at $59.33 per megawatt-hour (MW.h). Both gas-fired and ACR-700 units have comparable LUECs ($75.35 and $73.33/MW.h, respectively). The levelised unit electricity cost for the CANDU 6 reactor is significantly higher at $88.64/MW.h.

In general, the LUEC is lower under public financing for each technology because there are no income taxes payable and the cost of financing is lower. The impact on the LUEC of different technologies is not uniform since it varies with the proportion of capital (and hence debt) that is required. In the case of gas-fired generation, the least capital intensive option, the LUEC changed relatively little, from $75.35 under merchant financing to $72.05/MW.h under public financing. For both nuclear options the change is considerably larger, with both having a significantly lower LUEC than gas. The coal generation option remains the lowest in terms of levelised cost, but the cost difference between coal and the nuclear options is reduced.

The impact of the different financing assumptions is shown more clearly in Table 3.1 below. This table shows the LUEC broken down into a number of categories, such as capital expenditures and total operations and maintenance (O&M). For the gas-fired option, the capital expenditure costs and taxes make up a relatively small proportion of the total LUEC, with fuel costs being the largest component. For natural gas, lower capital costs and income taxes payable mean less debt interest payable for a merchant plant, and thus there appears to be little difference when we assume public financing. As noted in the previous section, 'public financing' can be thought to represent the underlying economic comparison of different options without distortions introduced by income taxes. For each of the nuclear options, under merchant financing, income taxes comprise approximately an eighth of the total LUEC, compared to less than a tenth for coal and about one thirty-fifth for gas.

Table 3.1: Levelised unit electricity cost (2003 $/MW.h)

Merchant	Coal	Gas	ACR-700	CANDU 6
	2003$/MW.h	*2003$/MW.h*	*2003$/MW.h*	*2003$/MW.h*
Capital Expenditures	$26.41	$10.21	$45.31	$57.17
Total O&M	$9.30	$5.02	$12.68	$15.08
Fuel	$18.04	$58.03	$5.45	$3.75
Decommissioning	$0.00	$0.00	$0.76	$1.17
Income Tax	$5.58	$2.10	$9.13	$11.47
LUEC	**$59.33**	**$75.35**	**$73.33**	**$88.64**

Public	Coal	Gas	ACR 700	CANDU 6
	2003$/MW.h	*2003$/MW.h*	*2003$/MW.h*	*2003$/MW.h*
Capital Expenditures	$20.38	$8.33	$34.58	$43.58
Total O&M	$9.30	$5.02	$12.57	$14.95
Fuel	$18.04	$58.71	$5.45	$3.75
Decommissioning	$0.00	$0.00	$0.75	$1.16
Income Tax	$0.00	$0.00	$0.00	$0.00
LUEC	**$47.72**	**$72.05**	**$53.36**	**$63.44**

* 2003 Canadian dollars per megawatt hour

It is also interesting to examine how robust the results presented above are to changes in assumptions. For example, CO_2 costs will impact the economics of the coal and gas technologies (increasing LUEC), especially with the larger heat rate of the pulverized coal units. Fuel costs account for the largest proportion of costs for gas-fired generation, but the economics of coal and nuclear technologies are quite robust to changes in their respective fuel prices. The operational lifetimes and capacity factors are important to the economics of all these technologies, but the relative importance depends on the mix of capital and fuel costs that make up the levelised costs for each option. Sensitivity tests and their impacts on the LUECs are presented in the next section. The sensitivities considered in this report are largely made with reference to the base case. It should be noted that such an approach is limited in that it does not consider possible correlations between risk factors (i.e. that the probability of one risk factor is linked to that of another).

CHAPTER 4: LUEC ANALYSIS OF THE SENSITIVITY CASES

4.1. Operational Lifetimes

The expected lifetime of operation differs among generating technologies. Gas-fired plants are expected to last up to 20 years, coal-fired plants around 40 years and nuclear plants from 40 to 60 years. Sensitivity tests were performed for 20 years and 40 years of operation, along with the base case of 30 years.

Table 4.1 shows that the LUEC for a merchant coal plant changes relatively little as operational life is extended, since in all scenarios half of the total capital cost is paid as debt over a period of 20 years. Under public financing there are no debt payments; thus the longer the project is in operation, the longer it has to recover a return on equity and the lower the resulting LUEC.

Gas-fired generation, on the other hand, is very sensitive to gas prices (also seen in Section 4.3). We have assumed that the gas price rises at an annual real rate of 1.8 percent until 2025 and thereafter remains constant. For the merchant case, as gas generation is assumed to remain in operation longer, it does so at a high fuel cost, resulting in an actual increase in the LUEC as plant life increases. With increasing gas prices, cash flows start to fall below zero. In the public financing case, the LUEC goes down as the operational lifetime is longer, but not significantly. The slight fall is attributable to there being more years to recover the required return on equity, but this effect is almost completely outweighed by the rising gas costs. The high proportion of

and public LUEC for each lifetime.

Nuclear projects have the highest capital cost per net megawatt-hour of the three technologies. We have also assumed that an extension of life from 30 to 40 years implies additional capital costs and a period of outage due to pressure tube replacement. Based on these assumptions, extending the life of the plant through pressure tube replacement appears to be an attractive option under public financing. Under merchant financing extending operational life appears less attractive, with the LUEC being similar at 30 and 40 years.

Table 4.1: Sensitivity of LUEC to assumed operational lifetime

	Merchant			Public		
	20	30 (base)	40	20	30 (base)	40
Coal	60.53	59.33	59.28	50.71	47.72	46.58
Gas	75.26	75.35	75.49	72.39	72.05	71.92
ACR-700	75.90	73.33	73.50	59.00	53.36	51.71
CANDU 6	91.99	88.64	88.82	70.69	63.44	61.38

4.2. Capacity Factors

Capacity factors indicate the percentage of net capacity that is actually used for production. The difference is due to planned maintenance, outages, and plant efficiency. Consequently, capacity factors are a function of the underlying technology and operational and management practices. In addition to our base case assumption of a capacity factor of 90 percent, we also consider how the technologies compare under assumed capacity factors of 85 and 95 percent.

Fuel costs and variable operating costs depend on the capacity factor. Thus, as the capacity factor increases more electricity is produced, but fuel and operating costs also increase. In all cases in Table 4.2, the overall LUEC decreases at a higher capacity factor and increases at a lower capacity factor.

It is interesting to note that a LUEC for a public CANDU 6 at 95 percent capacity and the three LUECs for the public ACR-700 are competitive with the merchant coal LUEC at 85 percent. Also, the ACR-700 technology at the three capacity factors is competitive with any of the three merchant coal cases. Again, however, the public coal cases still have the lowest LUECs.

Table 4.2: Sensitivity of LUEC to assumed capacity factor

	Merchant			Public		
	85%	90% (base)	95%	85%	90% (base)	95%
Coal	61.49	59.33	57.40	49.20	47.72	46.40
Gas	76.22	75.35	74.57	72.66	72.05	71.51
ACR-700	77.32	73.33	69.76	56.17	53.36	50.83
CANDU 6	93.63	88.64	84.17	66.95	63.44	60.30

4.3. CO_2 Costs

A key uncertainty in the economics of future generation is concerned with the impact of carbon dioxide (CO_2) costs on coal and gas-fired units. Burning coal or natural gas to generate heat produces emissions that enter the atmosphere and are accused of contributing to global warming. If penalties are imposed on the amount of CO_2 emissions produced, the economics of the coal and gas-fired units will be negatively affected. The impact on LUEC is greater for coal than gas due to higher levels of CO_2 emissions per unit of output. Note that we do not consider penalties being imposed on other types of emissions but have in all nuclear scenarios included a cost for the disposal of nuclear waste.

Table 4.3 shows that including a cost of $15 per tonne of CO_2 emitted into the atmosphere raises the merchant coal LUEC from $58 to $71 per megawatt-hour. At this cost level, merchant financed ACR-700 reactors appear competitive with the merchant coal. Under public financing both nuclear generating technologies have LUECs lower than or close to publicly financed coal.

The impact of CO_2 emission costs on gas-fired generation is less dramatic. However, given our assumptions about gas prices, gas-fired generation does not appear to be competitive with coal, even with the CO_2 costs included. This applies in both the merchant and public financing case.

Table 4.3: Sensitivity of LUEC to CO_2 emission costs

	Merchant		Public	
	Base Case	$15/t*	Base Case	$15/t
Coal	59.33	72.81	47.72	61.20
Gas	75.35	81.24	72.05	77.95
ACR-700	73.33	-	53.36	-
CANDU 6	88.64	-	63.44	-

* in 2003 Canadian dollars per tonne of emitted Carbon Dioxide

Table 4.4 shows the CO_2 costs needed to make the coal and gas LUECs equal to the nuclear LUECs. Even with relatively low emissions costs in the public finance case, the ACR-700 unit appears to be competitive with coal.

To conclude, if the estimated $15 per tonne of CO_2 cost is incurred, coal generation is still competitive with nuclear under merchant, but not public, financing. With $15 per tonne CO_2 costs, public financed ACR-700 becomes more economic than public coal, and the lowest LUEC overall.

Table 4.4: CO_2 emission costs to achieve equivalence between nuclear and non-nuclear LUEC

	Merchant		Public	
	ACR-700	CANDU 6	ACR-700	CANDU 6
Coal	15.58	32.63	6.27	17.50
Gas	< 0*	33.83	< 0*	< 0*

*Nuclear LUEC is smaller than the gas LUEC for any CO2 cost

4.4. Fuel Prices

In Table 4.5 we show a number of sensitivities relating to fuel prices. Changes in fuel price assumptions make a relatively small difference to the overall LUEC in the case of coal and nuclear options. This is even the case for nuclear, where we examine a large change in the uranium price (see Appendix A for details).

Fuel price sensitivities are more interesting in the case of natural gas, where the cost of fuel makes up a large proportion of the LUEC. Using a 0.8 percent real annual increase in natural gas prices up to 2025, instead of the base case assumption of 1.8 percent real increase per year, lowers the merchant LUEC by $9.17 to $66.18 per megawatt-hour and lowers the public LUEC by $7.55 to $64.15 per megawatt-hour. At this level, gas-fired generation appears to be more competitive with ACR-700 technology under merchant financing, but not public financing.

Table 4.5: Sensitivity of LUEC to assumptions regarding fuel price

Merchant	Coal	Gas	ACR-700	CANDU 6
Base Case	59.33 *(level)*	75.35 *(+1.8%/a)*	73.33 *(level)*	88.64 *(level)*
+0.5%/year	60.01	-	-	-
-0.5%/year	58.69	-	-	-
+0.8%/year	-	66.18	-	-
+$0.50, level	-	-	73.83	89.14
-$0.50, level	-	-	72.83	88.14
Public	Coal	Gas	ACR-700	CANDU 6
Base Case	47.72	72.05	53.36	63.44
+0.5%/year	48.58	-	-	-
-0.5%/year	46.92	-	-	-
+0.8%/year	-	64.15	-	-
+$0.50, level	-	-	53.86	63.94
-$0.50, level	-	-	52.86	62.94

Italics represent base case assumptions for that variable.

4.5. Technology – Plant Costs and Heat Rates

Due to changing technology, a new plant may have cost and efficiency characteristics better than assumed in our base case. For the coal case, a 6 percent increase (decrease) in plant cost ($100 per net kilowatt) increases (decreases) the merchant LUEC by $2/MW.h and increases (decreases) the public LUEC by $1.27/MW.h. The effect is higher for the merchant case because of the impact of debt payments that depend directly on the capital costs. For gas-fired generation that impact of changes in capital costs is relatively small.

Advances in technology may also result in greater efficiency, indicated by a lower heat rate for the plant. If more power could be extracted from the fossil fuels, the heat rate would go down, and less CO_2 would be emitted per unit of electricity. The LUECs are lower with lower heat rates, shown in Table 4.6. A 9.3 percent drop in the coal heat rate lowered the merchant coal LUEC by 1.7 percent and the public coal LUEC by 2.1 percent. A 5.6 percent drop in the gas heat rate decreased the merchant gas LUEC by 7.1 percent and the public gas LUEC by 7.6 percent. The economics for the gas cases are more sensitive to heat rate changes than the coal cases because fuel costs come directly from the cost of fuel and the heat rate.

Improved heat rates mean less fuel is needed to produce a unit of electricity, which means fewer emissions per unit of produced electricity. Comparing LUECs with a lower heat rate while including CO_2 costs yielded a merchant coal LUEC that decreased by 2.4 percent and a public LUEC that decreased by 2.6 percent. The LUECs decreased by a larger percentage than the decreases without considering CO_2 costs, since there is an added bonus – along with smaller fuel costs are lower emission costs. The merchant gas LUEC dropped by 7.3 percent and the public gas LUEC dropped by 7.7 percent when CO_2 costs were included. Again, these are larger drops without CO_2 due to the emission savings.

Table 4.6: Sensitivity of LUEC to assumptions regarding coal and natural gas technology

Plant Costs	Merchant		Public	
	Coal	Gas	Coal	Gas
Base Case	59.33 *($1600)*	75.35 *($711)*	47.72	72.05
$1,500/kWnet	57.33		46.45	
$1,700/kWnet	61.33		49.00	
$915/kWnet		79.02		74.44
Heat Rates	Merchant		Public	
	Coal	Gas	Coal	Gas
Base Case	59.33 *(9000)*	75.35 *(7000)*	47.72	72.05
8,500 Btu/kW.h	58.33	-	46.72	-
6,350 Btu/kW.h	-	70.01	-	66.60
Heat Rates & $15/t CO2 Cost	Merchant		Public	
	Coal	Gas	Coal	Gas
Base Case($15/t)	72.81	81.24	61.20	77.95
8,500 Btu/kW.h	71.05	-	59.45	-
6,350 Btu/kW.h	-	75.35	-	71.95

In this report our base case for the twin ACR-700 has examined the expected capital cost and construction time of a 'first of a kind' unit. Construction times and costs are thought to diminish significantly for additional units. Table 4.7 shows the estimated LUEC for an 'nth of a kind' ACR-700 build. A public financed 'nth of a kind' project is competitive with the base case for coal and significantly lower than for gas or for coal with emission costs included. The LUEC for a merchant

ACR-700 ‘nth of a kind’ is $63/MW.h, which is close to the merchant coal base case LUEC of $59/MW.h and also significantly lower once emissions costs of $15/t of CO_2 are included.

We note that CANDU 6 technology is well understood and less likely to be subject to uncertainty. For completeness, we also consider a case where the cost of a ‘first of a kind’ ACR-700 plant is 20 percent higher than anticipated. This increase raised the merchant LUEC by 14.5 percent to $84 and the public LUEC by 12.6 percent to $60. At this cost, the public LUEC for the ACR-700 is higher than the merchant coal base case LUEC of $59/MW.h, but still lower when emission costs are included.

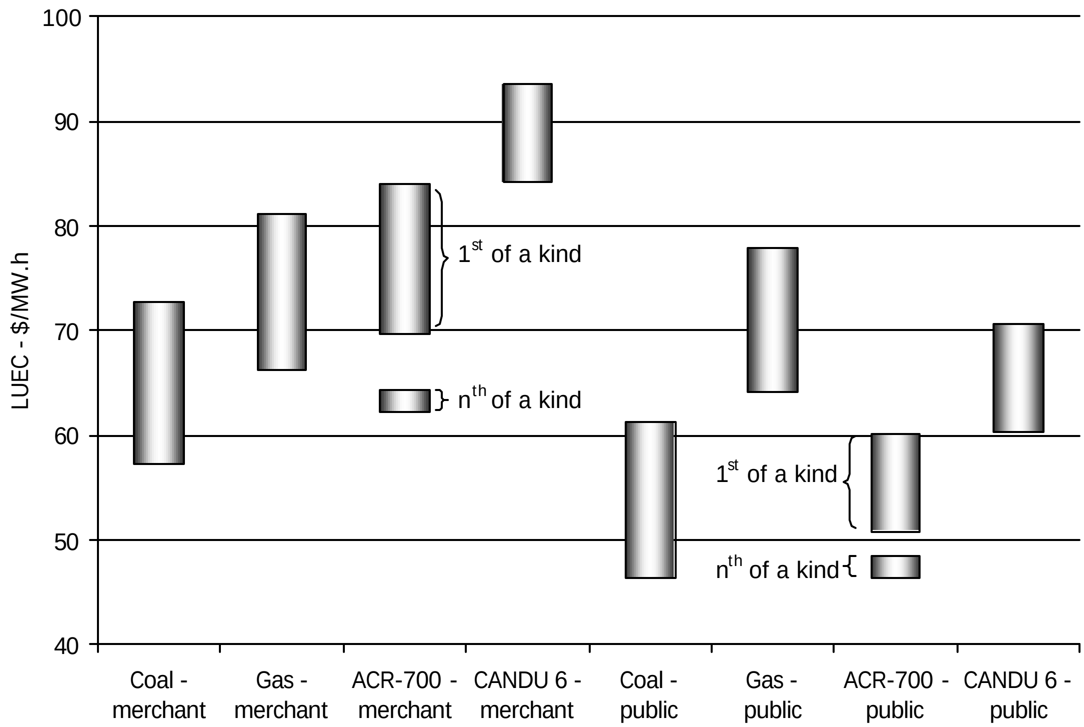
Table 4.7: Sensitivity to changes in assumptions of ACR-700 technology

	Merchant	Public
Base Case *($3300M)*	73.33	53.36
Plant Cost up 20% *($3960M)*	83.94	60.09
Nth of a kind *($2900M plant cost, shorter construction period)*	63.28	47.42

4.6. Summary of Sensitivity Tests

In Figure 4.1 below we present a summary of the base case and sensitivities considered in this report. Detailed results of all the different scenarios are presented in Appendix E. This gives a representation of the range of possible LUECs for each option. Considering all of the sensitivities presented in this report, the overlap between coal and ACR-700 options (particularly under public financing) indicates that new coal and ACR-700 reactors could be considered competitive under a range of possible scenarios. This is particularly the case under public financing or in comparing new coal with an ‘nth of a kind’ ACR reactor.

Figure 4.1: Summary of estimated LUEC



4.7. Financial Assumptions: Sensitivity Analysis

4.7.1. Merchant Financing & Public/Private Partnerships

For merchant financing we have, for all generation options, assumed a base case real cost of debt of 8 percent, a real cost of equity of 12 percent and a 50/50 debt/equity ratio. There is uncertainty whether private investment would be forthcoming given this return on equity and as to the cost of borrowing for private companies. Returns needed by private companies may be lower under some form of public/private partnership (where some risk is borne by the public sector). Public/private partnerships may also allow access to lower-cost debt. Without knowing the exact form of public/private partnership, estimating the LUEC is difficult. Consequently, we have considered a large range of possible sensitivities, assuming a return of equity of between 12 and 20 percent, debt/equity ratios of 50/50 and 70/30, and a cost of debt of 6 and 8 percent. These sensitivities are intended to provide an illustration of how the relative costs of generating options change with assumptions regarding financing rather than representing an explicit public/private partnership arrangement.

The results for each of the sensitivities described above are summarized in Figures 4.2 to 4.5. The more capital intensive the project, the more sensitive its LUEC is to changes in assumptions regarding the cost of debt and equity. Thus, the impact is greatest for the CANDU-6 technology and lowest for gas-fired generation. Consequently, the relative competitiveness of natural gas-fired generation, judged solely form the perspective of LUEC, increases significantly as the weighted cost of capital increases. All of the results presented below assume that the costs and operating characteristics used in our base case apply.

Figure 4.2: Merchant financing assuming a debt/equity ratio of 50/50 and a real cost of debt of 8%

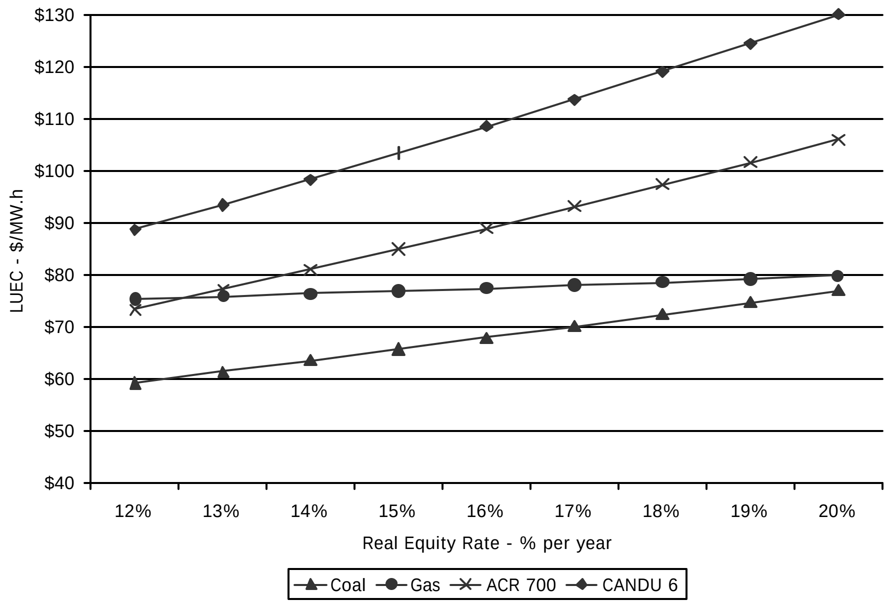


Figure 4.3: Merchant financing assuming a debt/equity ratio of 70/30 and a real cost of debt of 8%

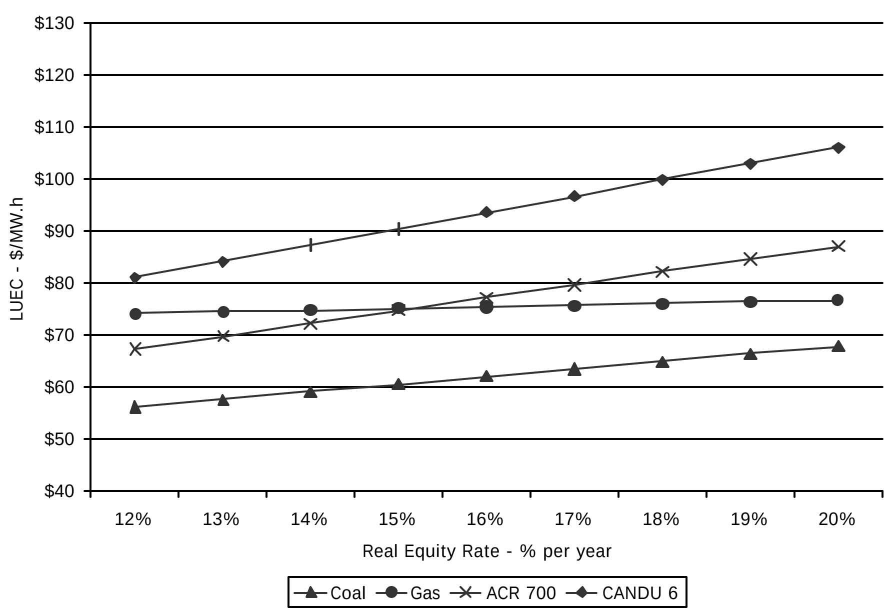


Figure 4.4: Merchant financing assuming a debt/equity ratio of 50/50 and a real cost of debt of 6%

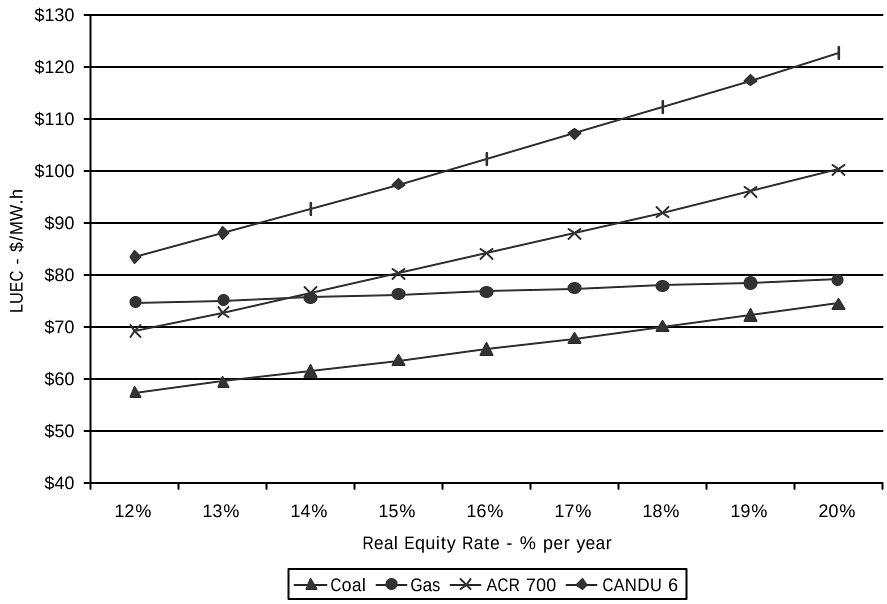
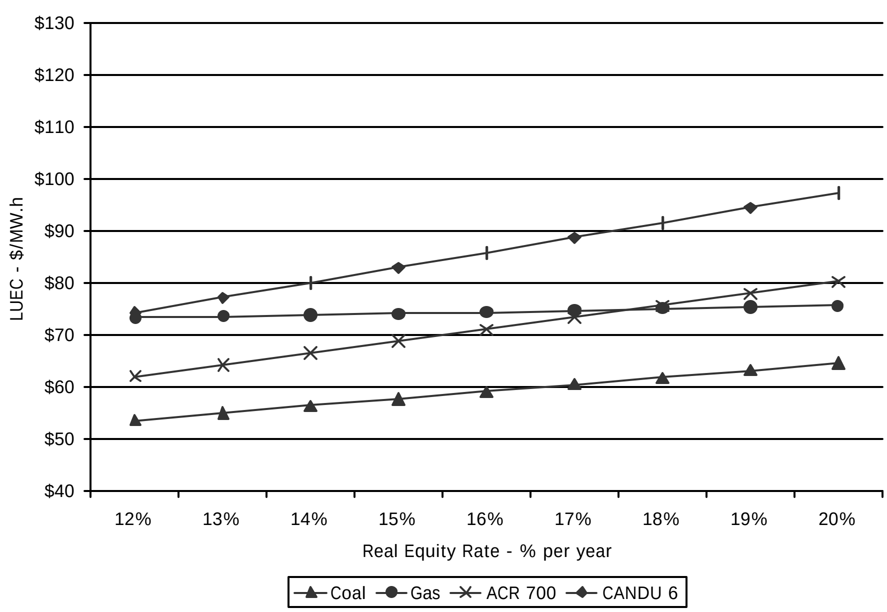


Figure 4.5: Merchant financing assuming a debt/equity ratio of 70/30 and a real cost of debt of 6%

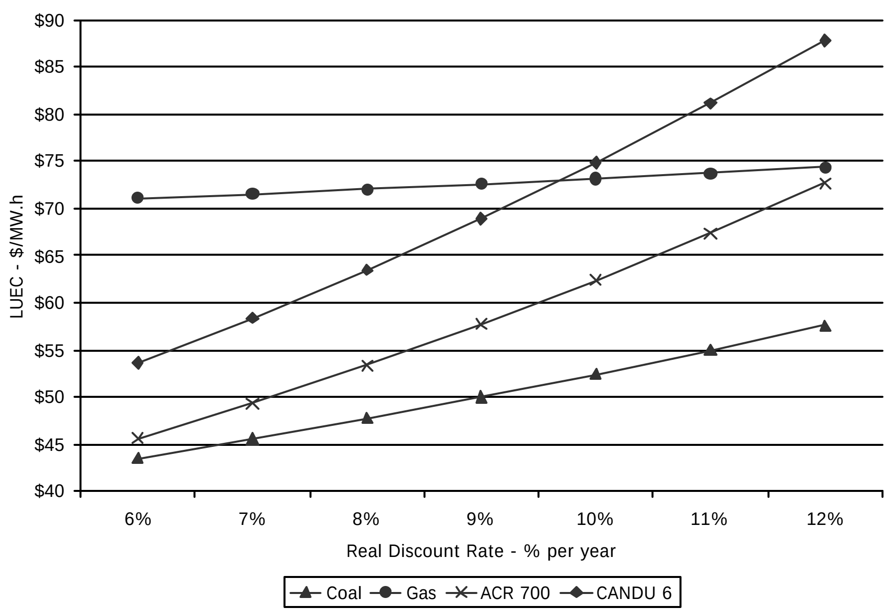


4.7.2. Public Financing

In recognition of the uncertainty over the true cost of financing public projects, we consider the impact of real discount rates between 6 and 12 percent (base case 8 percent). Further discussion of the 'correct' discount rate to use in consideration of public projects (sometimes referred to as the social discount rate) is given in Appendix C.

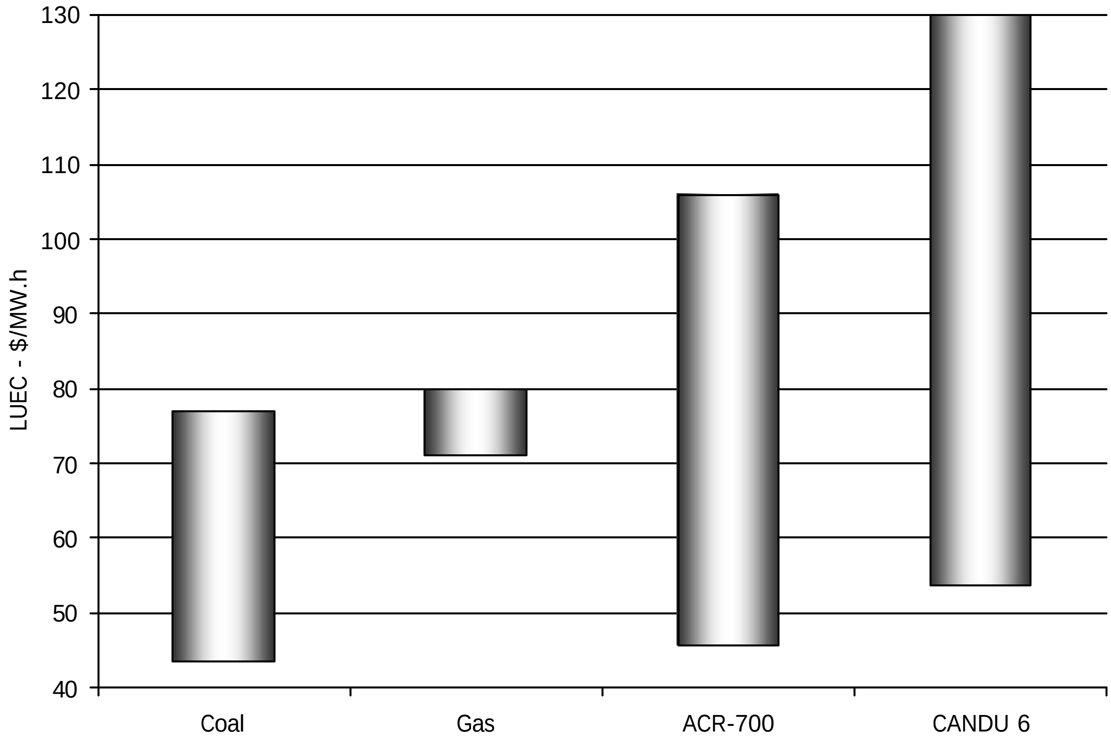
The results of this sensitivity analysis are shown in Figure 4.6 below. The overall pattern is similar to the sensitivities examined under merchant financing, with the LUEC increasing the most for capital intensive technologies, as the assumed real discount rate is higher. We note that in most of the sensitivities examined, natural gas-fired generation continues to have the highest LUEC. All of the results presented below assume that the costs and operating characteristics used in our base case apply.

Figure 4.6: Public financing: impact of discount rate on LUEC



In Figure 4.7 below we present a summary of the range of financing sensitivities shown in Figures 4.2 to 4.6. Detailed results of all the different sensitivities are presented in Appendix E. As noted above, the estimated LUEC of gas-fired generation is significantly less sensitive to changes in financing assumptions, whereas financing assumptions can change the estimated LUEC significantly for the more capital intensive technologies.

Figure 4.7: Summary of estimated LUEC under different financing assumptions



APPENDIX A: FUEL PRICES

In this appendix we review data and forecasts of fuel prices for coal, gas and nuclear generation. Based on this review, we propose a 'base case' scenario. It is defined in terms of a set of assumptions. Also, where appropriate, we indicate possible sensitivity analyses for each fuel.

A.1. Coal

A.1.1. Price of Coal in Ontario for Electric Power Generation

In the tables below we present data from Statistics Canada on coal purchases for Ontario electric power generation for the period 1999-2001. The average weighted price of coal for electric power generation in Ontario (expressed in 2003 Cdn$/GJ) has fallen over the period from $2.33 (1999) to $2.03 (2000) and finally to $1.95 (2001).

The tables below suggest that the price of coal varies significantly by type of coal. It is our understanding that new supercritical pulverized coal plants are likely to be fuelled with high sulphur bituminous coal to take full advantage of the flue gas desulphurization systems.

Data for 2003 from the Energy Information Administration (EIA) indicate a U.S. steam coal price for electric generators of Cdn$1.86/GJ (2003).[8] Additional transportation costs in Ontario would suggest a higher coal price is justified in Ontario.

Table A.1: Coal Purchases in Ontario for Electric Power Generation by Type, 1999

Type	Percentage	$ Cdn /GJ (1999)	$ Cdn /GJ (2003)
Canadian Bit.	7.2%	2.16	2.39
Imported Bit.	63.7%	2.32	2.56
Imported Sub-Bit.	17.1%	1.47	1.63
Lignite	11.9%	1.55	1.71
Weighted average	**100.0%**	**2.10**	**2.33**

Table A.2: Coal Purchases in Ontario for Electric Power Generation by Type, 2000

Type	Percentage	$ Cdn /GJ (2000)	$ Cdn /GJ (2003)
Canadian Bit.	0.0%	0	0
Imported Bit.	62.9%	2.09	2.25
Imported Sub-Bit.	27.1%	1.46	1.57
Lignite	10.0%	1.46	1.57
Weighted average	**100.0%**	**1.88**	**2.03**

8 Equivalent to US $1.24/MMBtu (2002 dollars) assuming an exchange rate of 70 cents US to the Cdn. dollar.

Table A.3: Coal Purchases in Ontario for Electric Power Generation by Type, 2001

Type	Percentage	$ Cdn /GJ (2001)	$ Cdn /GJ (2003)
Canadian Bit.	1.4%	2.31	2.43
Imported Bit.	57.9%	2.13	2.24
Imported Sub-Bit.	29.9%	1.38	1.45
Lignite	10.8%	1.40	1.47
Weighted average	**100.0%**	**1.85**	**1.95**

Source: Statistics Canada, catalogue 57-202-XPB, Table 6 various years.

A.1.2. Future Coal Prices

Differences in coal price forecasts indicate that there is some uncertainty over future prices. Estimates range from a long-term decline of approximately 1 percent per year to a long-term increase of 0.5 percent per year:

- The EIA's Annual Energy Outlook (2004) forecasts that steam coal prices for U.S. electric generators will decrease from $1.25 in 2002 to $1.18 (US$/MMBtu) in 2025 (equivalent to a decrease of 0.3 percent per year in real terms over the period 2002-2025);
- The recent long-term forecast by the National Energy Board (NEB) notes that coal prices will decline by 1 percent per year until 2015, then remain at these levels until 2025;[9] and
- The MIT (2003) study assumes that coal fuel costs for electric power generation will increase in real terms by 0.5 percent per year.[10]

A.1.3. Coal Price Assumptions

Base Case:

Based on the above information, we have assumed that coal prices will remain constant in real terms at an estimated Cdn$1.95/GJ (2003).

Sensitivities:

Given the difference in future coal price forecasts, we consider two illustrative cases:

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9 National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (2003) http://www.neb-one.gc.ca, Figure 3.4, page 23.

10 Massachusetts Institute of Technology. *The Future of Nuclear Power: An Interdisciplinary MIT Study (July 29, 2003)*, page 43. Available at http://www.mit.edu/afs/athena/org/n/nuclearpower/. Accessed January 7, 2004.

1. *0.5 percent real annual increase in prices*

2. *0.5 percent real annual decrease in prices*

A.2. Natural Gas

Long-term forecasts indicate that natural gas prices will increase. It is noteworthy that the range across the various forecasts is considerable (see Table A.4 below).

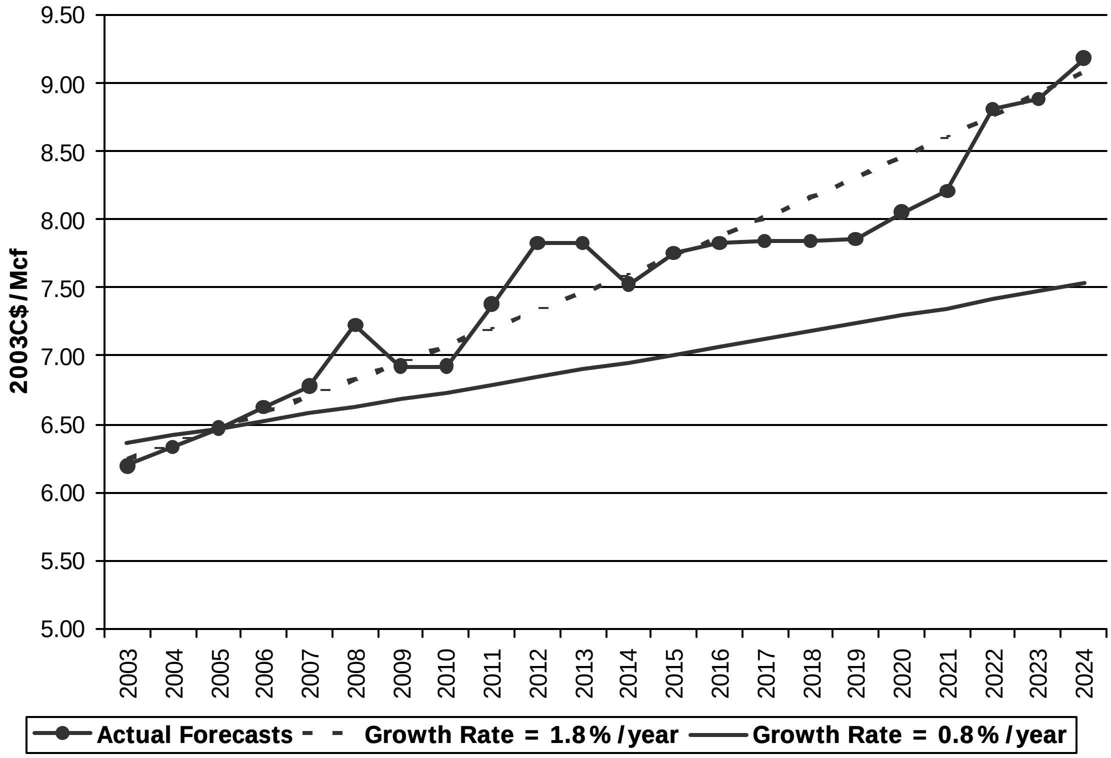
Table A.4: Forecast Annual Percentage Increase in Natural Gas

Source	Annual Percentage Increase
NEB	0.4 to 0.95
MIT	0.5, 1.5 and 2.5
CERI	1.8
EIA	0.8

The EIA *Annual Energy Outlook* (2004) projects that natural gas prices for electric generators will increase by 0.8 percent per annum over the 2005-2025 period.[11] In contrast, the CERI natural gas price forecast for Dawn, Ontario predicts an average annual real increase of 1.8 percent per annum for the 2005 to 2025 period. Figure A.1 below shows the actual CERI price projections for Dawn, Ontario (indicated as Actual Forecasts), as well as a 1.8 percent and 0.8 percent annual increase from 2005 onwards. A base year of 2005 was selected, when gas prices are assumed to be $6.47 (2003 Cdn $) in both the CERI and EIA forecasts.

11 Energy Information Administration, *Annual Energy Outlook 2004 with Projections to 2025.* DOE/EIA-0383 (2004), AEO Detailed Annexes, Table 3.

Figure A.1: CERI Gas Price Forecasts at Dawn, ON



Other forecasts published by the National Energy Board (NEB) and those used in a recent study by MIT suggest a similar range of possible increases for natural gas prices: The NEB (2003)[12] projects that the price of natural gas will move from about US$3.25/MMBtu (2001 dollars) in 2003 to US$3.50/MMbtu (2001 dollars) in 2025 under the *Supply Push* scenario and from $3.25 to $4.00 under the *Techno-Vert* scenario by 2025. This is equivalent to a real escalation rate of 0.4 percent and 0.95 percent for the *Supply Push* and *Techno-Vert* scenarios, respectively.[13]

The MIT (2003) study assumes three different gas price forecasts in its analysis of coal versus natural gas and nuclear generating options:

1. a low gas price that starts with gas prices at US$3.50/MMBtu, increasing at a real rate of 0.5 percent over 40 years;

2. a moderate gas price starting at US$3.50/MMBtu, increasing at a real rate of 1.5 percent per year over 40 years; and

12 National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (2003) http://www.neb-one.gc.ca, Figure 3.3, page 23.

13 National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (2003) http://www.neb-one.gc.ca, Figure 3.3, page 23.

3. a high gas price that starts at US$3.50/MMBtu, increasing at a real rate of 2.5 percent over 40 years.[14]

A.2.1. Natural Gas Price Assumptions

Base Case:

Consistent with our own forecast, we have assumed that the natural gas price at Dawn, Ontario would be $6.47 (2003 Cdn $) in 2005, increase by 1.8 percent per year until 2025 and then remain constant thereafter.

Sensitivities:

Given the differences among natural gas price forecasts, we also consider a sensitivity case where the natural gas price increases by 0.8 percent per year until 2025 and then remains constant thereafter, based on the long-term price forecasts presented in the EIA's Annual Energy Outlook 2004.

A.3. Uranium

Fuel costs for nuclear plant are typically divided into two parts: a *front-end cost,* which includes the cost of uranium, enrichment and fabrication; and a *back-end cost* based on the cost of transportation from the power plant to disposal in a spent fuel facility.

Based on information form Atomic Energy of Canada Limited (AECL), the front-end cost breakdown for the ACR fuel is as follows:

- Uranium concentrate 26%
- Enrichment 59%
- Fabrication 15%

AECL estimates that the front-end fuel cost for the ACR-700 is approximately $4/MW.h. The CANDU 6 front-end fuel cost is approximately $2.3/MW.h. Both include costs associated with dry storage.

A 2001 U.S. Department of Energy Report[15] estimated a back-end fuel cost of US$1/MW.h for spent nuclear fuel or approximately Cdn$1.45/MW.h at a conversion rate of 70 cents US to the

14 Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study* (July 29, 2003), page 43. Available at http://www.mit.edu/afs/athena/org/n/nuclearpower/. Accessed January 7, 2004.

15 U.S. Department of Energy (2001): *Nuclear Waste Fee Fund Adequacy: An Assessment,* DOE/RW-0534, Washington, D.C., page 1.

Canadian dollar. Given the similar heat content of fuel used in U.S. reactors and in the ACR-700 and CANDU 6, we have assumed that this provides a reasonable basis for estimating the back-end fuel costs.

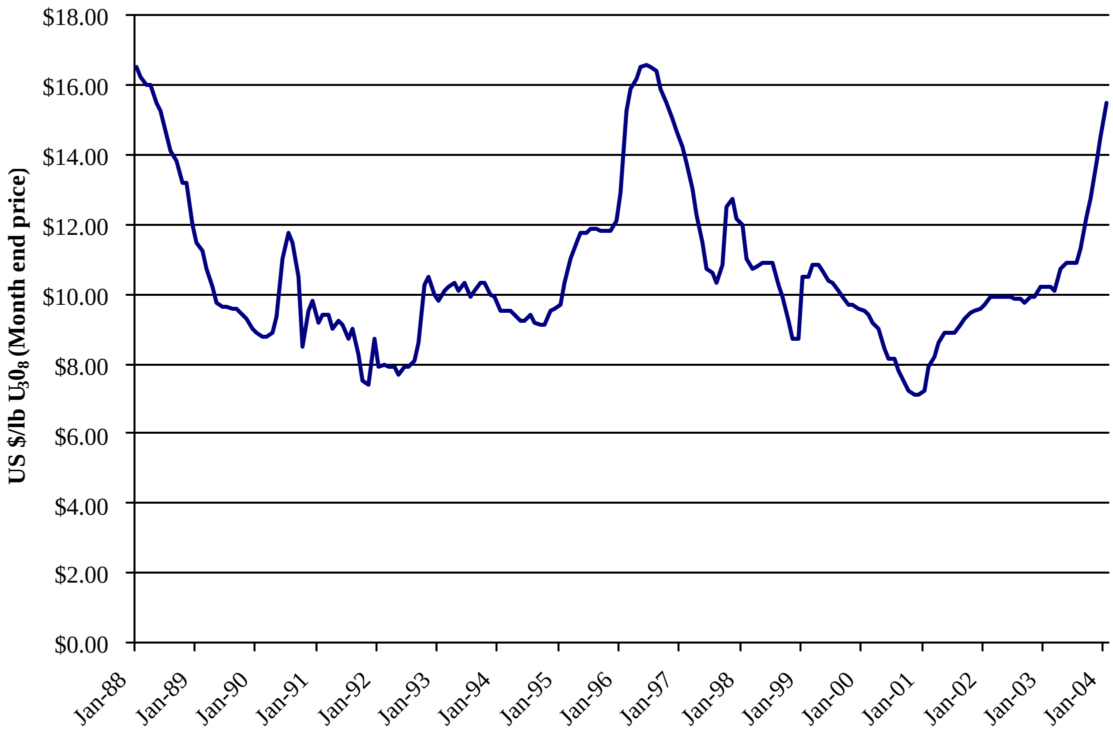
Table A.5: Summary of Estimated Front-end and Back-end Fuel Costs for ACR-700 and CANDU 6 Reactors (2003 Cdn $ / MW.h)

	Twin ACR-700	Twin CANDU 6
Fuel Cost	4.00	2.30
Spent Fuel Cost	1.45	1.45

Figure A.2 below shows historical uranium spot prices. We note that over the last 15 years uranium spot prices have fluctuated between approximately US$7 to US$16 per pound. In 2003, the uranium spot prices increased by over 40 percent.[16] Information from the EIA *Annual Energy Outlook* (2004) forecasts an annual long-term real rate of decline in price of 0.4 percent from a 2003 value of $0.4019 (2001$/MMBtu). We also note that new nuclear plant may also purchase uranium under long-term contracts rather than at spot prices.

16 Source: http://www.cameco.com.

Figure A.2: Historical Uranium Spot Prices



Source: accessed at http://www.cameco.com/investor_relations/ux_history /historical_ux.php on Februrary 22, 2004.

A.3.1. Uranium Price Assumptions

Base Case:

In the base case, we assume a front-end fuel cost for the ACR-700 and CANDU 6 reactors of $4.00/MW.h and $2.30/MW.h, respectively. We assume these will remain constant in real terms.

Sensitivity:

In recognition of the current uncertainty in the forecast level of uranium prices, we consider illustrative sensitivities where uranium prices are 50 percent higher and 50 percent lower than indicated in our base case. Since the cost of uranium concentrate represents approximately one quarter (26 percent) of the front-end fuel cost for the ACR-700 reactor, we consider the case where fuel costs are $0.50 higher and lower (i.e. $3.50/MW.h and $4.50/MW.h). We consider a similar illustrative range for front-end fuel costs for the CANDU 6 reactor (i.e. of $1.80/MW.h and $2.80/MW.h).

APPENDIX B: COST AND PERFORMANCE CHARACTERISTICS OF NEW ELECTRICITY GENERATING TECHNOLOGIES

The cost and performance data of the different electric generating technologies contained in this appendix are based on publicly available information. The primary data source for gas and coal-fired generation was the Energy Information Administration's (EIA's) *Assumptions for the Annual Energy Outlook 2003 with Projections to 2025* (January 2003). This was supplemented with additional information received directly from the EIA and from Canadian sources in the public domain. We also show data from a recent study by MIT, although we note that the original source of data for that study was also the EIA. For the two nuclear options considered in this study, no review was conducted; instead, data on the twin ACR-700 and CANDU 6 reactors were provided directly to us from Atomic Energy of Canada Limited (AECL).

Of the recent Canadian sources reviewed, three are of particular interest:

- A press release from ATCO and Ontario Power Generation provides some information on the station capacity and plant cost of a new combined cycle gas turbine (CCGT) plant in Windsor, Ontario, due to come online during 2004.[17]

- A September 12, 2003 presentation by P. Charlebois, Chief Nuclear Engineer to the Supply Task Force,[18] provides LUECs for different technologies and limited information on station capacity and plant cost for coal and natural gas-fired generating stations.

- A November 12, 2003 presentation by Brian Vaasjo of EPCOR[19] presented information on the costs associated with the new EPCOR super-critical Genesee 3 plant compared to the costs of conventional pulverized coal combustion.

It is important to note that the composition of what is included in O&M costs is not precisely known. For example, the EIA does not provide details on what is included in O&M costs. The values for new plants are obtained from industry reviews and vendor estimates that typically do not provide detailed breakdowns. The EIA does not assume any additional annual capital costs, just recovery of the initial capital investment. The O&M costs for existing plants are from the FERC Form 1 filings and they would not account for costs of outages, other than typical planned maintenance. Based on our review of the available data, we suggest a set of 'base case' assumptions and, where appropriate, an illustrative range of sensitivity cases.

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17 News release: Brighton Beach Power Completes Largest Independent Power Project Financing in Canadian History, October 1, 2002.

18 Ontario Power Generation, 'Industry LUECs', part of a presentation entitled *Nuclear Fleet Life Management Outlook,* September 12, 2003.

19 Presentation at the BMO Nesbitt Burns Pipelines and Energy Utility Conference, November 12, 2003.

B.1. Scrubbed Coal-Fired Generation

Table B.1 presents cost and performance data collected from various sources for coal-fired generation.

Table B.1: Cost and Performance Characteristics of Coal-Fired Generation

Variable	Units	Currency Type (if applicable)	Source of Data	Originally Reported as (if applicable)[1]	
Station Capacity	600 MW	EIA (AEO 2003)[2]			
	1000 MW	MIT[3]			
	500 MW	OPG Clean Coal FGD/SCR[4]			
	450 MW	EPCOR Presentation Nov. 12, 2003[5]			
Plant Cost	$1,737/kW *($1,042 million)*	C$2003	EIA (AEO 2003)	$1,154/kW	US$2001
	$1,904/kW *($1,904 million)*	C$2003	MIT	$1,300/kW	US$2002
	$1,760/kW *($880 million)*	C$2003	OPG	$1,720/kW	C$2002
	$1,545/kW *($695 million)*	C$2003	EPCOR	$1,545/kW	C2003$
Project Schedule	4 years	EIA (AEO 2003)			
	4 years	MIT			
	4 years	DOE			
	5 years	IEA 1998[6]			
	4 years	EPCOR			
Project Cash Flow	Yr 1: 65% Yr 2: 20.0% Yr 3: 10.0% Yr 4: 5.0%				EIA
	Yr 1: 3.1% Yr 2: 16.1% Yr 3: 30.8% Yr 4: 34.1% Yr 5: 15.9%				IEA 1998
Production Costs					
Fixed O&M	$36.91/kW/yr	C$2003	EIA (AEO 2003)	$24.52/kW/yr	US$2001
	$33.68/kW	C$2003	MIT	$23.00/kW/yr	US$2002
	$6 - 7/MW.h	C$2003	EPCOR	$6 to $7/MW.h	C$2003
Variable	$4.62/MW.h/yr	C$2003	EIA (AEO 2003)	$3.07/MW.h/yr	US$2001
	$4.95/MW.h/yr	C$2003	MIT	$3.38/MW.h/yr	US$2002
Total O&M Costs	$37.16 million/yr	C$2003	EIA (AEO 2003)	(assume 80% capacity factor)	
	$61.66 million/yr	C$2003	MIT	(assume 80% capacity factor)	
Other O&M notes	0%/yr real escalation of O&M costs			EIA (AEO 2003)	
	1.096%/yr real escalation of O&M costs			MIT	
Ongoing Capital Expenditure	$0/kW/yr	$C2003	EIA		
	The EIA / DOE assume no additional capital costs, just recovery of initial capex.				
	$21.96/kW/yr	C$2003	MIT	$15/kW/yr	US$2002
	($1.76 million/yr for an 80% capacity factor)				
Decommissioning Cost	$0	DOE assumes no annual decommissioning costs			
	$0	MIT assumes no decommissioning costs for coal-fired units			
Heat Rate	9000 Btu/kW.h for first units 8600 Btu/kW.h for nth of a kind or by 2010			EIA (AEO 2003)	
	9300 Btu/kW.h			MIT	
	8500 - 9500 Btu/kW.h			EPCOR	

1. Assumed U.S. to Canadian dollar exchange rate and for inflation rates to 2003 Canadian dollars specified in Appendix C.
2. Email correspondence from U.S. Department of Energy, Energy Information Administration, January 30, 2004 and February 12, 2004, expanding on Table 40, Cost and Performance Characteristics of New Electricity Generating Technologies, Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003 with Projections to 2025,* DOE/EIA-0554(2003), January 2003, page 73.
3. Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study,* July 29, 2003, pages 43 and 135.
4. Ontario Power Generation, 'Industry LUECs', part of a presentation entitled *Nuclear Fleet Life Management Outlook* by P. Charlebois, Chief Nuclear Engineer to the Supply Task Force, September 12, 2003.
5. Brian Vaasjo, Executive Vice President, EPCOR, *Coal-Fired Generation.* presentation at the BMO Nesbitt Burns Pipelines and Enertgy Utility Conference, November 12, 2003.
6. Nuclear Energy Agency, International Energy Agency, *Projected Costs of Generating Electricity: Update 1998,* Paris, 1998.

B.1.1. Station Capacity

Based on the information provided in Table B.1, typical new coal-fired plant has a net capacity from 450 to 600 MW. Since most other cost assumptions are input on a per kW basis, the assumed station capacity does not directly affect the levelised unit cost. For example, the MIT analysis assumes a station capacity of 1000 MW for all new electric generating options – coal, gas and nuclear – for its LUEC comparison. For our analysis, we assume a station capacity of 500 MW based on the typical size of new coal-fired plant.

B.1.2. Plant Cost

The base case assumes a coal plant cost of Cdn$1600/kW (2003). This represents the lower end of the range of cost data presented for new coal-fired generating plants. It is consistent with a recent analysis by EPCOR and is roughly halfway between the cost estimates presented in Table B.1 for OPG and EPCOR.[20] To account for the installed cost of a new coal plant being somewhat lower or somewhat higher than this, sensitivity cases will be assessed for a cost of Cdn$1500/kW and Cdn$1700/kW (2003).

B.1.3. Project Schedule and Cash Flow Expenditure

Data from the EIA's *Annual Energy Outlook Assumptions* for 2003 indicate a four-year project schedule with 65 percent of costs incurred in the first year. This differs significantly from the five-year profile presented by the International Energy Agency (IEA). The EIA has confirmed with us

20 Brian Vaasjo, Executive Vice President, EPCOR, 'Coal-Fired Generation', presentation at the BMO Nesbitt Burns Pipelines and Enertgy Utility Conference, November 12, 2003.

that a five-year profile is most appropriate and the four-year profile used in their analysis was due to limitations in their modelling framework.

For this reason, we have used a project schedule of five years and a construction cash flow profile based on information from the IEA[21] (as reported in Table B.1).

B.1.4. Fixed and Variable O& M Costs

We assume the Energy Information Administration AEO 2003 assumptions for fixed O&M and variable O&M of $36.91/kW/yr and $4.62/MW.h/yr and also accept their assumption of no real O&M cost escalation.

B.1.5. Ongoing Capital Expenditures

We acknowledge that, especially with a long operating life, there would likely be costs associated with refurbishment. However, we can find no reliable estimates of these costs. The impact on overall LUEC of refurbishment costs is likely to be small in present value terms. Consistent with the EIA, we assume no additional capital costs, simply recovery of the initial capital.

B.1.6. Decommissioning Cost

All power plants require some decommissioning. However, we are unable to find estimates of the likely cost for decommissioning new coal-fired generation. Given that decommissioning occurs at the end of the plant's life, costs may be small in present value terms. Consistent with the EIA assumptions, we assume no decommissioning costs for coal-fired generating capacity.

B.1.7. Heat Rate

We assume the EIA heat rate of 9000 Btu/kW.h for new coal generating stations and also consider, as a sensitivity case, the EIA's projection of an 8600 Btu/kW.h heat rate for future plants.

B.2. Combined Cycle Gas Turbine (CCGT)

Table B.2 summarizes the cost and performance data we collected from various sources for new gas-fired generation.

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21 Nuclear Energy Agency, International Energy Agency. *Projected Costs of Generating Electricity: Update 1998.* Paris, 1998.

Table B.2: Cost and Performance Characteristics of Gas-Fired Generation

Variable	Units	Currency Type (if applicable)	Source of Data	Originally Reported as (if applicable)[1]	
Station Capacity	400 MW		AEO 2003[2]		
	1000 MW		MIT[3]		
	375 MW		Charles - River[7]		
	580 MW		Atco Power & OPGI's Brighton Beach[8]		
	500 MW		OPG[4]		
Plant Cost	$915/kW *($366 million)*	C$2003	AEO 2003	$608/kW	US$2001
	$732/kW *($732 million)*	C$2003	MIT	$500/kW	US$2002
	$780/kW *($293 million)*	C$2003	Charles - River	$742/kW	C$2001
	$711/kW *($412 million)*	C$2003	Brighton Beach	$695/kW	C$2002
	$767/kW *($384 million)*	C$2003	OPG	$375 million	C$2002
Project Schedule	3 years		EIA (AEO 2003)		
	2 years		MIT		
	2 years		Charles - River		
Project Cash Flow	Yr 1: 10% Yr 2: 20% Yr 3: 70%		EIA (AEO 2003)		
	Yr 1: 50% Yr 2: 50%		MIT		
	Yr 1: 12% Yr 2: 50% Yr 3: 38%		IEA 1998[6]		
Production Costs					
Fixed O&M	$15.38/kW/yr	C$2003	EIA (AEO 2003)	$10.22/kW/yr	US$2001
	$23.43/kW	C$2003	MIT	$16.00/kW/yr	US$2002
	$24.70/kW/yr	C$2003	Charles - River	$23.49/kW/yr	C$2001
Variable	$3.07/MW.h/yr	C$2003	EIA (AEO 2003)	$2.04/MW.h/yr	US$2001
	$0.76/MW.h/yr	C$2003	MIT	$0.52/MW.h/yr	US$2002
	$2.37/MW.h/yr	C$2003	Charles - River	$2.25/MW.h/yr	C$2001
Total O&M Costs	$13.53 million/yr	C$2003	EIA (AEO 2003)	(assume 80% capacity factor)	
	$24.07 million/yr	C$2003	MIT	(assume 80% capacity factor)	
	$13.62 million/yr	C$2003	Charles - River	(assume 80% capacity factor)	
Other O&M notes	0%/yr real escalation of O&M costs			EIA (AEO 2003)	
	1.096%/yr real escalation of O&M costs			MIT	
Ongoing Capital Expenditure	$0/kW/yr	$C2003	Charles - River		
	$0/kW/yr	$C2003	EIA (AEO 2003)		
	The EIA assumes no additional capital costs, just recovery of initial capex.				
	$8.79/kW/yr	C$2003	MIT	$6/kW/yr	US$2002
	($7.03 million/yr for an 80% capacity factor)				
Decommissioning Cost	$0	EIA assumes no annual decommissioning costs			
	$0	MIT assumes no decommissioning costs for gas-fired units			

Heat Rate	7000 Btu/kW.h for first units 6350 Btu/kW.h by 2010	EIA (AEO 2003)
	7200 GJ/GW.h 6400 GJ/GW.h for advanced	MIT
	6600 - 6900 Btu/kW.h	Charles - River

1. Assumed U.S. to Canadian dollar exchange rate and for inflation rates to 2003 Canadian dollars specified in Appendix C.
2. Email correspondence from U.S. Department of Energy, Energy Information Administration, January 30, 2004 and February 12, 2004, expanding on Table 40, Cost and Performance Characteristics of New Electricity Generating Technologies, contained in Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003 with Projections to 2025,* DOE/EIA-0554(2003), January 2003, page 73.
3. Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study.* July 29, 2003, pages 43 and 135.
4. Ontario Power Generation, 'Industry LUECs', part of a presentation entitled *Nuclear Fleet Life Management Outlook* by P. Charlebois, Chief Nuclear Engineer to the Supply Task Force, September 12, 2003.
5. Brian Vaasjo, Executive Vice President, EPCOR, *Coal-Fired Generation,* presentation at the BMO Nesbitt Burns Pipelines and Enertgy Utility Conference, November 12, 2003.
6. Nuclear Energy Agency, International Energy Agency, *Projected Costs of Generating Electricity: Update 1998,* Paris, 1998.
7. Charles River Associates, *A Revised Basis for Estimating the Standard Supply Service Reference Price Upon Opening of the Retail Electricity Market in Ontario, Canada,* report prepared for the Ontario Energy Board, July 24, 2001, page 18.
8. ATCO Power and Ontario Power Generation, news release: *Brighton Beach Power Completes Largest Independent Power Project Financing in Canadian History,* October 1, 2002.

B.2.1. Station Capacity

As shown in Table B.2, new CCGT plant size typically ranges from 375 MW to 580 MW. For our analysis, we assume a station capacity of 580 MW consistent with the Brighton Beach CCGT plant currently under construction in Windsor, Ontario.[22]

B.2.2. Plant Cost

As shown in Table B.2, the cost of a new CCGT ranges from $711/kW to $915/kW. For our base case, we assume the figure of $711/kW based on the Brighton Beach plant. Given the relatively large range of per kW plant costs, we also consider a sensitivity case of $915/kW based on data from the EIA (2003).

22 ATCO Power and Ontario Power Generation, news release: *Brighton Beach Power Completes Largest Independent Power Project Financing in Canadian History,* October 1, 2002.

B.2.3. Project Schedule and Cash Flow Expenditure

As shown in Table B.2, both the MIT and the Charles River studies indicate a project schedule of two years. A two-year schedule is also consistent with the planned construction of the Brighton Beach plant. We have assumed equal cash flow is required in each year of the construction period. This is consistent with the project cash flow profile, shown in Table B.2, used in the MIT study.

B.2.4. Fixed and Variable O&M Costs

We assume the fixed and variable O&M costs of $15.38/kW/yr and $3.07/MW.h/yr, respectively, based on data from the EIA's *Annual Energy Outlook* 2003. These values are similar to those assumed in the 2001 Charles River study for the Ontario Energy Board.

B.2.5. Ongoing Capital Expenditures

We acknowledge that, especially with a long operating life, there would likely be costs associated with refurbishment. However, we can find no reliable estimates of these costs. The impact on the overall LUEC of refurbishment costs is likely to be small in present value terms. Consistent with the EIA, we assume no additional capital costs, simply recovery of the initial capital.

B.2.6. Decommissioning Cost

All power plants require some decommissioning. However, we are unable to find estimates of the likely cost for decommissioning new coal-fired generation. Given that decommissioning occurs at the end of the plant's life, costs may be small in present value terms. Consistent with the EIA assumptions, we assume no decommissioning costs for coal-fired generating capacity.

B.2.7. Heat Rate

In our base case, we assume a heat rate in 2002 of 7000 Btu/kW.h and we also assume a sensitivity case where technology is available such that the heat rate declines to 6350 Btu/kW.h. Both assumptions are consistent with data from the EIA.

B.3. Twin ACR-700 and Twin CANDU 6 Nuclear Reactors

Data for the twin ACR-700 and CANDU 6 reactors contained in this section were supplied by AECL.

B.3.1. Station Capacity

In Table B.3 below we summarize the capacity for each unit of the ACR-700 and CANDU 6 designs. We have assumed both would operate as twin units, giving a net output of 1406 and 1346 MWe, respectively. The design life for reactors is 60 years for the ACR-700 and 40 years for the CANDU 6.

Table B.3: Station Capacity

	ACR- 700	CANDU 6
Gross Output per Unit (MWe)	753	728
Net Output per Unit (MWe)	703	673

B.3.2. Plant Cost

In Table B.4 we summarize the overnight capital cost and owners' cost of both types of reactor. These costs assume the plant is built on an existing site with a 'once through cooling water system' (i.e. no cooling towers). Given that the ACR-700 represents new technology, it is expected that the cost for reactors will decline as more units are constructed. Table B.4 contains estimates of the costs associated with first (units 1 & 2) and subsequent builds.

Table B.4: Plant Costs for Twin ACR-700 and CANDU 6

	ACR-700			CANDU 6
	Unit 1/2	**Unit 3/4**	**Unit 5/6**	**Twin unit**
Overnight Capital Cost	3000	2800	2600	3700
Owners' Cost	300	300	300	300
Total Plant Cost	**3300**	**3100**	**2900**	**4000**

The 'overnight capital cost' includes costs of engineering design and safety analysis, procurement, equipment supply, module fabrication, construction/installation, project management, commissioning start-up, heavy water and initial fuel load, and licensing support but excludes financing costs. The 'owners' cost' includes costs of project approvals, permits and licences, owners' project management, site preparation (including site services and access roads), construction indirects (water, electricity during construction), owners' facilities (switchyard, intake and discharge, guard house, administration building), training of owners' staff and participation in start-up and security.

B.3.3. Project Schedule and Cash Flow Expenditure

In Table B.5 we show the project schedule and the proportion of total plant cost incurred in each year of construction. For the first pair of ACR-700 and CANDU 6 units, the first unit is assumed to be in operation after approximately 60 months with the second unit in operation nine to twelve months later. Also shown in the table is the project schedule for the third pair of ACR-700 units constructed (units 5 & 6). Note that in addition to the lower capital cost (see Table B.4 above), the construction time is also expected to be lower for repeat builds.

Table B.5: Project Cash Flow

Months	0	12	24	36	48	60	72
ACR-700 Units 1 & 2	8.0%	21.0%	27.1%	19.6%	12.0%	7.2%	5.1%
ACR-700 Units 5 & 6	8.0%	22.3%	28.7%	20.7%	12.7%	7.6%	
CANDU 6	8.0%	21.0	27.1%	19.6%	12.0%	7.2%	5.1%

B.3.4. Fixed and Variable O&M Costs

Operation and maintenance (O&M) for the ACR-700 are estimated to be $10.85/MWh and for the CANDU 6 estimated to be $12.90/MWh. For the twin ACR-700 this is equivalent to a total cost of $108 million per year with an outage cost per unit of $33.5 million every three years. The annual cost for the twin CANDU 6 for O&M is a total of $136 million.

O&M costs for the nuclear units include: core costs (materials and labour), support costs (head office, external services), outage costs (labour, materials and services), regulatory fees, insurance, local taxes and other expenses such as memberships.

B.3.5. Ongoing Capital Expenditures

For both ACR-700 and CANDU units we understand there is an ongoing annual capital expenditure of $5 million per unit.

B.3.6. Pressure Tube Replacement

After 30 years of operation each unit of the ACR and CANDU 6 reactors would likely undergo pressure tube replacement at a respective cost of $200 and $270 million. In scenarios where we have assumed an economic life of 30 years or less, we have not included these costs.

B.3.7. Decommissioning Costs

Decommissioning for both types of reactor is expected to take 43 years and comprises three phases:

- Phase I – Reactor Shutdown, Decommissioning and Decontamination;
- Phase II – Dormancy Period (under continuous surveillance); and
- Phase III – Final Decommissioning to Unrestricted Use (includes transfer of waste to permanent repository.

The estimated cost for decommissioning the twin CANDU 6 reactor is $760 million. Preliminary estimates by AECL of the cost of decommissioning the ACR-700 reactor indicate a lower decommissioning cost due to its simplified design. In Table B.6 below we show the estimated annual provision under different assumptions regarding the economic life of the plant.

Table B.6: Decommissioning Costs (Annual Provision, millions of dollars)

Economic Life	20 years	30 years	40 years
Annual Provision	11	8	5

B.4. Summary of Base Case Information and Sensitivity Cases

Based on the information noted above, we summarize in Table B.7 below the various assumptions we selected for the base case LUEC model runs as well as the sensitivity cases.

Table B.7: Base Case Summaries

Variable	Coal	Natural Gas	Nuclear Twin ACR-700	Nuclear Twin CANDU 6
Station Capacity Gross			1506 MW	1456 MW
Net	500 MW	580 MW	1406 MW	1346 MW
Plant Cost	$1,600/kW net *($800 million)*	$711/kW net *($412 million)*	$2,347/kWnet *($3,300 million)*	$2,972/kW net *($4,000 million)*
Operating Life	30 years	30 years	30 years	30 years
Project Schedule	4 years	2 years	6 years	6 years
Project Cash Flow				
(down payment) Year 0	3.1%	0.0%	8.0%	8.0%
Year 1	16.1%	50.0%	21.0%	21.0%
Year 2	30.8%	50.0%	27.1%	27.1%
Year 3	34.1%		19.6%	19.6%
Year 4	15.9%		12.0%	12.0%
Year 5			7.2%	7.2%
Year 6			5.1% (in op'n)	5.1% (in op'n)
Production Costs				
Fixed O&M	$36.91/kW/yr	$15.38/kW/yr	$10.85/net MW.h/yr	$12.90/net MW.h/yr
Variable	$4.62/MW.h/yr	$3.07/MW.h/yr	$0/MW.h/yr	$0/MW.h/yr
On-going Capital Expenditure	$0	$0	$10M per year	$10M per year
Decommissioning Cost	$0	$0	$8M per year	$8M per year
Heat Rate	9000 Btu/kW.h	7000 Btu/kW.h		
Capacity Factor	90%	90%	90%	90%
Fuel Costs	$1.90/GJ level level from yr-to-yr	$6.47/Mcf (in 2005) + 1.8% real / yr	$4.00 / net MW.h level	$2.30/ net MW.h level
Spent Fuel Cost	$0	$0	$1.45 / net MW.h	$1.45 / net MW.h
Sensitivities				
Capacity Factor	85% 95%	85% 95%	85% 95%	85% 95%
Plant Cost	$1,500/kW $1,700/kW	$915/kW	Plant Cost +20% Nth of a kind	
Heat Rate	8,500 Btu/kW.h	6,350 Btu/kW.h		
Fuel Costs	+0.5% real / year -0.5% real / year	+0.8% real / year	+$0.50 level -$0.50 level	+$0.50 level -$0.50 level
Operating Life	20, 40 years	20, 40 years	20, 40 years	20,40 years
CO_2 Emission Costs	$15/t	$15/t		

APPENDIX C: ECONOMIC AND FINANCIAL ASSUMPTIONS

To undertake the LUEC assessment of merchant and public sector financing of coal, natural gas and nuclear electric power generating options, various assumptions have to be made with respect to the split between debt and equity financing, the costs of debt and equity, and other factors. Outlined below are some economic and financial assumptions presented by various organizations, together with the assumptions for these factors we found appropriate to the LUEC analysis.

C.1. Economic Assumptions

C.1.1. Forecast Exchange Rate

As shown in Appendix B above, much of the costing information we relied upon for our LUEC comparative analysis was taken from sources published by the U.S. Energy Information Administration and then converted into 2003 Canadian dollars. To make the forecasts appropriate for electric power plants coming on-stream in 2012, we had to make an assumption about the long-term purchasing parity between the U.S. and the Canadian dollar. We decided on a rate of US70 cents to the Canadian dollar as something that reflects the long-term exchange rate over the past 10 years and in the future. In part we based this assumption on a report by the TD Bank Financial Group (2004).

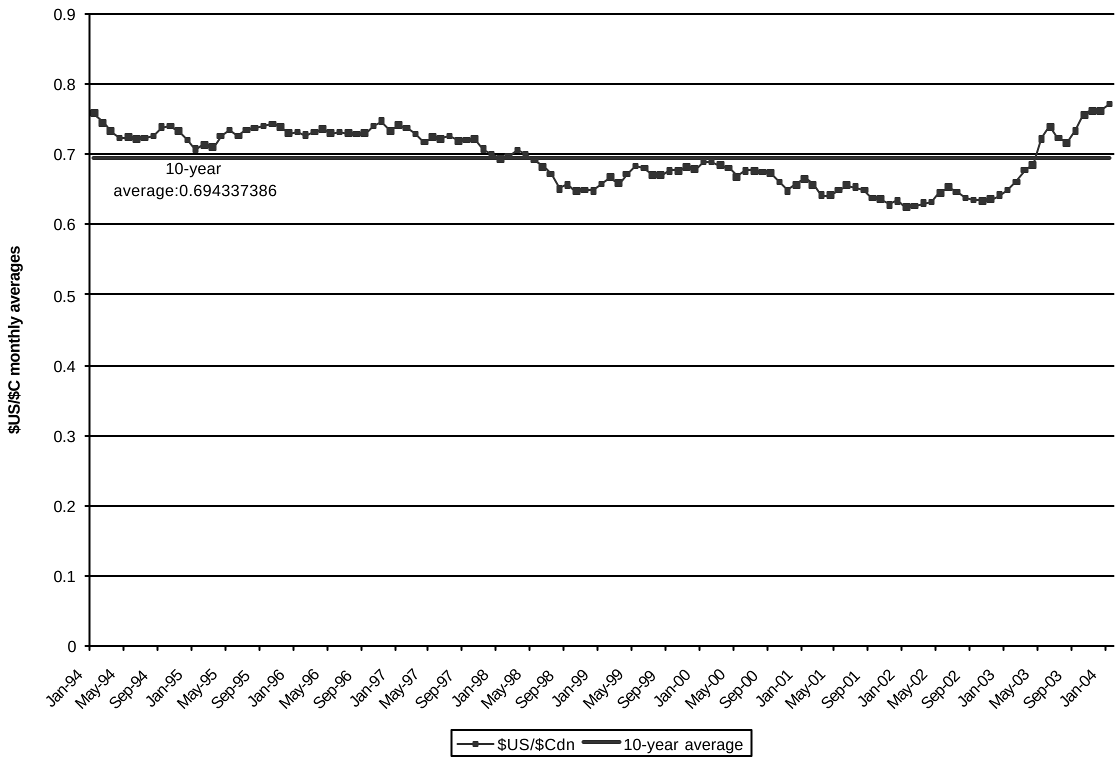
In 2003, the average exchange rate was 71.41. However, as presented in Figure C.1, the rate has varied significantly over the January 1994 to January 2004 period, with a 10-year average of 69.4.

In a recent analysis of the rally in the Canadian dollar and its consequences, the TD Bank discusses the purchasing power parity (PPP) as the most common and popular measure of a currency's fair value. The idea behind PPP is that a currency's value relative to another currency should reflect relative price levels in the two countries involved.[23] This Bank report notes a number of sources for the purchasing parity rate ranging from a low of 72 cents to a high of 89 cents. One source cited in this study is titled Fundamental Equilibrium Exchange Rate, Bank of Canada Equation, which gives a PPP of 68 to 72 cents.

Given the exchange rate range exhibited in Figure C.1 and the Bank of Canada PPP rate of 68 to 72 cents noted above, we have chosen to use a purchasing parity rate of US70 cents to the Canadian dollar.

23 TD Bank Financial Group, *Loonie Tunes – Understanding the Rally in the Canadian Dollar and Its Consequences,* TD Economics Special Report, February 10, 2004, pages 4-5.

Figure C.1: US/Cdn Dollar Exchange Rate 1994-2004



Source: Bank of Canada web site, http://www.bankof canada.ca accessed February 18, 2004.

C.1.2. Conversion to 2003 Canadian Dollars

In converting cost data to 2003 dollars we have used the inflation factors given in Table C.1 below:

Table C.2: Historical Inflation, 2000-2003

Year	US Inflation (percent)	Canadian Inflation (percent)
2000	2.40	2.73
2001	1.40	2.50
2002	2.80	2.80
2003	2.50	2.30

Source: Bank of Canada.

In case it was necessary to convert data reported in U.S. dollars, we have first inflated the number to U.S. 2003 dollars and assumed an exchange rate of $0.70 US/Cdn to convert the number into 2003 Canadian dollars.

C.2. Future Inflation Rate

The National Energy Board (NEB, 2003)[24] shows a forecast range of 1.9 to 2.1 percent until 2025 under the *Supply Push* scenario. Under the *Techno-Vert V* scenario the same range is assumed until 2020, increasing to 2.4 percent thereafter. We also note that the Bank of Canada's target for core inflation is 2.0 percent and that most forecasts for the medium and long term appear to assume inflation will remain close to this target.

For comparison, the EIA (2003) assumes average U.S. inflation in the long term will be 2.5 percent, and the study by MIT (2003) assumes an average of 3 percent.

Based on the information above and in the interest of simplicity, we assume a constant inflation rate of 2 percent per year.

C.3. Public Sector Financing

For the public sector financing scenario, we adopted the common assumptions used to evaluate projects by provincially owned electric generating monopolies across Canada. No income taxes are included. The real discount rate is used to determine the LUEC that matches the costs of generating electricity and the revenues attributed to this generation. Given these assumptions, this scenario can also be interpreted as one based on the fundamental economics rather than incorporating any distortions implied by income taxes,[25] the tax treatment of depreciation or specific financing assumptions regarding the cost of debt and equity.

In the evaluation of public projects, the Treasury Board of Canada recommendation is that a 'social discount rate' should be roughly the opportunity cost of capital, weighted according to the source of investment capital.[26] The Treasury Board has concluded for risk analysis that a useful range for the consideration of the real social discount rate is 8-12 percent per annum with a most likely value of 10 percent real per annum. This recommendation dates from the Treasury Board's 1976 *Benefit Cost Analysis Guide.* Other sources have suggested a lower discount rate may be justifiable for long-lived projects and that the current opportunity cost of capital may be below this level.

Consequently, we have considered as a base case a real discount rate of 8 percent. Our selected discount rate is also approximately the same as the EIA's assumed long-term real cost of debt for the 2000-2025 period (8.6 percent).

24 NEB 2003, page 19.

25 Ontario Power Generation has been required to pay 'proxy taxes'. We do not include any such payments in our analysis.

26 Treasury Board of Canada (1998), *Benefit Cost Analysis Guide.*

C.4. Merchant (Private Sector) Financing

For private sector financed LUEC evaluation of generating options, there is a need to make various assumptions that have a bearing on income taxes and the cost of raising debt and equity capital to finance the project. Assumptions are needed for each type of generation technology for the following:

- Income tax rates;
- Debt/equity ratios;
- Cost of debt and equity; and
- Debt life.

In the sections below, we consider some of the assumptions made in other LUEC studies and present our rationale for deciding on specific assumptions for our assessment.

C.4.1. Income Tax Rate

- Ontario Power Generation's *2002 Annual Report*[27] notes that the effective income tax rate for 2001 was 30.3 percent.

- Charles River Associates (2001)[28] assumed an effective income tax (combined federal and provincial) of 30.12 percent for 2006 and onwards.

Based on these reports, we assume an effective income tax rate of 30 percent for the LUEC comparison of coal, natural gas and nuclear power generating options.

C.4.2. Debt/Equity Ratio

- The MIT (2003) study assumes equity of 40 percent and debt of 60 percent for the coal and gas-fired generation options scenarios. But nuclear is assumed to have a 50/50 debt/equity split, reflecting the higher regulatory risks and commercial risks associated with uncertainties about construction and operating costs that presently burden nuclear compared to fossil-fuelled alternatives.

- EIA (2003) assumes a debt fraction of 55 percent for all three options, and the debt and equity rates vary over time.

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27 Ontario Power Generation, 2002 Annual Report, page 18.

28 Charles River Associates (2001), *A Revised Basis for Estimating the Standard Supply Service Price Upon Opening of the Retail Electricity Market in Ontario*, Revision 1, prepared for the Ontario Energy Board, July 24, 2001, page 18.

Based on the information above, we assume a 50/50 debt/equity split for the LUEC analyses of the three generating options. We also consider a sensitivity analysis showing the impact of moving to a 70/30 debt/equity ratio for each generating technology..

C.4.3. Cost of Equity

- The EIA[29] estimates the cost of equity on outputs from their National Energy Modeling System (NEMS) model. For the period from 2000 to 2025, they estimate an average *real* rate of 14.7 percent for equity.

- The MIT (2003) study assumes a *nominal* return to equity of 15 percent for nuclear and 12 percent for coal and natural gas plants. The study assumes an inflation rate of 3 percent. This yields real rates of 12 and 9 percent for the cost of equity for nuclear and coal plant, respectively.

- Charles River Associates (2001, page 18) assumes a real required rate of return on equity of 11.3 percent.

Based on the information presented above, we evaluate a base case assuming a real return on equity of 12 percent is required. We also consider a sensitivity analysis illustrating the impact of assumed real return on equity of between 12 and 20 percent.

C.4.4. Cost of Debt

- Charles River Associates (2001)[30] assumed a long-term nominal debt cost of 8.1 percent for new CCGT (inflation rate assumed to be 2.2 percent).

- The EIA[31] average estimate of the real cost of debt on outputs from the NEMS model for the period from 2000 to 2025 is 8.6 percent.

- MIT (2003) assumes a cost of debt of 8 percent nominal, with inflation of 3 percent.

Based on the above information, we assume a real rate of 8 percent for the cost of debt. As a sensitivity we also consider the impact of a lower cost of debt (6 percent).

C.4.5. Debt Life

- MIT assumes a debt life of 10 years for all three options – nuclear, gas and coal.

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29 Based on an email from the EIA dated January 30, 2004.

30 Charles River Associates (2001), *A Revised Basis for Estimating the Standard Supply Service Price Upon Opening of the Retail Electricity Market in Ontario*, Revision 1, prepared for the Ontario Energy Board, July 24, 2001, page 18.

31 Based on an email from the EIA dated January 30, 2004.

- EIA (2004)[32] assumes debt life of 20 years.

- Charles River (2001) assumes debt life of 20 years.

Consistent with the EIA Annual Energy Outlook and Charles River analysis, we assume a debt life of 20 years for all three generating options, nuclear, gas and coal.

C.4.6. Depreciation

We take a simple approach to dealing with depreciation, assuming straight-line depreciation on all assets. In practice, different depreciation rules may be applicable to different classes of asset. Rules for depreciation for particular assets may also be subject to change. We note approaches taken in other reports:

- Ontario Power Generation has in the past assumed straight-line depreciation in its calculation of proxy income taxes payable to the Province of Ontario.

- Charles River in its 2001 assessment of the economics of a new CCGT assumed a 30 percent declining balance in its analysis of capital cost allowance (page 18).

Based on the above, we assume a straight-line depreciation schedule over the life of the plant.

32 Based on an email from the EIA dated January 30, 2004.

C.5. Summary of Financing Scenarios

Based on the information noted above, we summarize in Table C.2 the assumptions made in each financing scenario.

Table C.2: Financing Scenarios

Variable	Public Financing	Merchant Financing
Income Tax Rate	0%	30%
Discount Rate	8% real	weighted average
Debt Rate	N/A	8% real
Equity Rate	N/A	12% real
Debt/Equity Ratio	N/A	50/50
Debt Life	N/A	20 years
Depreciation	N/A	straight-line over lifetime
Exchange Rate	$0.70US/Cdn	$0.70US/Cdn
Inflation Rate	2% per year	2% per year
Sensitivities		
All combinations of Debt Rate, Equity Rate, and Debt/Equity Ratio	6-12% real discount rate	50/50 and 70/30 d/e ratio 6% and 8% debt rates 12-20% equity rates

APPENDIX D: CERI LUEC MODEL DESCRIPTION

CERI's LUEC model calculates the levelised cost of generating a unit of power, under certain assumptions, for a specific project. The model is set up to calculate a LUEC for a nuclear, natural gas-fired or coal-fired generating project. The general assumption in the model is that any generating unit under consideration is owned and operated by an enterprise whose sole asset would be the generating unit. The construction duration and lifetime of a project are variable, and can last up to 128 years combined. For this report, the operating lifetimes will range from 20 to 60 years, with construction duration ranging from two to eight years.

The levelised cost in this model is the same as a supply cost, whereas the unit cost is the price needed to set the sum of all future discounted cash flows (net present value, in real dollars) to zero. Cash flows are made up of costs and revenues. Costs include capital expenditures, operating and maintenance costs, fuel costs, and any taxes and decommissioning costs. The revenue stream comes from the sale of electricity, at the calculated unit supply cost (LUEC). The discount rate (rate of return) is a weighted average of the cost of debt (if any) and the cost of equity.

The model was created in a Microsoft Excel® environment, with Visual Basic code for automation. There is an input sheet, several calculation sheets, and a summary sheet with the resulting LUEC and entered inputs.

D.1. Inputs

Model inputs included financial and technical data specific to the project. Any inputs irrelevant to the project, like working capital, cost escalations, decommissioning costs, tax rates for a publicly funded project, etc., are set to zero. Sensitivity cases are also tested in the same manner, by changing the input values of the variables of interest and running the model again.

- General financial inputs include:
    - Initial debt ratio
    - Debt life in years
    - Real debt rate
    - Real equity rate
    - Total income tax rate (federal and regional)
    - Working capital

- Project-specific financial and technical inputs include:
    - Base year of currency inputs
    - Start year of construction
    - Start year of operation
    - Gross capacity

- Net capacity
- Annual capacity factors
- Annual capital expenditures
- Annual delivered fuel cost
- Fixed operating and maintenance costs
- Variable operating and maintenance costs
- O&M real escalation rate
- Decommissioning costs
- Heat content and heat rate
- CO_2 emissions rate
- Cost of CO_2 emissions

D.2. Calculations

From the user-entered inputs, the model computes annual values of revenue (the LUEC multiplied by the annual energy production from the net capacity and annual capacity factors), cash outflows (capital expenditures, operating costs, taxes, debt repayments including interest), and annual cash flows available to equity holders. These annual *real dollar* cash flows (revenues minus outflows) are discounted by the weighted average of the debt and equity rates, and the electricity price needed to achieve this discount rate is computed as the LUEC.

All currency inputs are entered in constant dollars in the base year specified, and the LUEC is also computed in real dollars for that year. For this report, all currencies are in 2003 Canadian dollars.

The annual capital expenditures are inputted on a per *gross* kilowatt basis, and the dollars spent per year is the product of that year's per-kilowatt spending and the gross capacity. Operating and maintenance costs and decommissioning costs are based on *net* capacity, and fuel costs per year are based on *net* capacity and the annual capacity factors.

Computed taxes are in nominal dollars, and are converted back into real dollars using the inflation rate entered by the user. The debt ratio is held constant during the construction year(s). Straight-line depreciation is used, over the operational lifetime of the project.

Fuel costs can be entered in a number of ways – in dollars per megawatt-hour; dollars per million Btu; dollars per thousand cubic feet or dollars per gigajoule, annually, in real dollars. The heat rate is needed if fuel costs are not in dollars per megawatt-hour, which is generally the case for coal and gas-fired inputs. The fuel cost per megawatt-hour for a certain year is multiplied by the capacity factor for that year and the net capacity to get fuel costs in real dollars per annum.

CO_2 emissions are based on the emission factor (tonnes of CO_2 per terajoule of energy used) and the fuel use for each year. The cost of emissions per tonne of CO_2 is an input, and is used as a sensitivity to compare coal and gas economics to emission-free nuclear economics.

Decommissioning costs can also be entered in a number of ways. An annual cost, in dollars per megawatt-hour (mills per kilowatt-hour) can be entered; and/or a cost, in millions of real dollars, in the last year of operations can be used. It is up the user to decide if the project has an annual decommissioning cost expensed over the lifetime of the project, and/or has a cost at the end of the project's life that can be discounted significantly the longer the project lasts (for cash flow purposes).

D.3. Results

The resulting LUEC is presented in the model's summary sheet. The breakdown of the LUEC is also shown, to see how much of each component contributes to the derived supply cost. The LUEC is found using the goal seek approach – by changing the supply cost until the NPV of future cash flows is zero, given the discount rate. The cash flows used in the goal seek method are all in *real* dollars, in the base year inputted by the user.

An example of the summary sheet is presented below in Figure D.1. This sheet summarizes all user inputs and the model's calculated LUEC and its components.

Figure D.1

INPUTS - CERI LEUC Model

Basic Input Data		
Name of Project		
Base Year		
Starting Year of Construction		
First Year of Commercial Operation		
Initial Debt Ratio		
Debt Life		years
Debt Rate		%/a
Equity Rate		%/a
Total Income Tax Rate		%/a
Working Capital		% of Annual Op Cost
Average Annual Inflation		
Delivered Fuel Cost	see right table	
Technical Project Input Data		
Installed Capacity		MW
Project Life		Years
Capacity Factor		
Capital Expeditures		
Decommissioning Cost - Annual		2003/MW.h/yr (0 mills/kWh/yr)
Decommissioning Cost - last yr of oper'n		millions of 2002$
Fixed O&M Cost		2003$/kW.a
Variable O&M Cost		2003$/MW.h/yr (0.00 mills/kWh/yr)
O&M Real Excalation Rate		% per year
Heat Content		MMBtu/tcf
Conversion Factor		GJ/MMBtu
Heat Content	1.000	GJ/tcf
Heat Rate		GJ/MW.h (TJ/GW.h)
Conversion Factor	1	tcf/MW.h
CO2 Emissions:		t/TJ (0 kg/mmBTU)
Cost of CO2 Emissions		$/t
Sensitivity Analysis		
Add percent to Fuel Cost		

RESULTS:

The Levelized Electricity Cost is:	**$0.00**	(2003$/MW.h)
The IRR is:	**0.00%**	

Components of the LEUC:	2003$/MW.h
Capital Expenditures	$0.00
Total O&M	$0.00
Fuel	$0.00
Decommissioning	$0.00
CO2 Emissions	$0.00
Working Capital	$0.00
Income Tax	$0.00
Project Cash Outflow	**$0.00**

Year	Fuel Cost $/MW.h	Capacity Factor - %	Capital Exp $/kW
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
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2050			
2051			

Initial Overnight Capital Cost: ______ per kW

APPENDIX E: BASE CASE AND SENSITIVITY CASE RESULTS

Coal LUEC Results - $/MW.h

	Merchant	Public
Base Case	59.33	47.72
20 years in Operation	60.53	50.71
40 years in Operation	59.28	46.58
85% capacity factor	61.49	49.20
95% capacity factor	57.40	46.40
$15/t CO2 cost	72.81	61.20
Heat Rate - 8500 Btu/kW.h	58.33	46.72
8500 Btu/kW.h & $15/t CO2 cost	71.05	59.45
Coal Price - 0.5%/a	58.69	46.92
Coal Price + 0.5%/a	60.01	48.58
Plant Cost - $1500/kW	57.33	46.45
Plant Cost - $1700/kW	61.33	49.00

Gas LUEC Results - $/MW.h

	Merchant	Public
Base Case	75.35	72.05
20 years in Operation	75.26	72.39
40 years in Operation	75.49	71.92
85% capacity factor	76.22	72.66
95% capacity factor	74.57	71.51
$15/t CO2 cost	81.24	77.95
Heat Rate - 6350 Btu/kW.h	70.01	66.60
6350 Btu/kW.h & $15/t CO2 cost	75.35	71.95
Gas Price + 0.8%/a	66.18	64.15
Plant Cost - $915/kW	79.02	74.44

ACR-700 LUEC Results - $/MW.h

	Merchant	Public
Base Case	73.33	53.36
20 years in Operation	75.90	59.00
40 years in Operation	73.50	51.71
85% capacity factor	77.32	56.17
95% capacity factor	69.76	50.83
Fuel Price - $0.50 lower, level	72.83	52.86
Fuel Price - $0.50 higher, level	73.83	53.86
Plant Cost - 20% higher	83.94	60.09
Nth-of-a-kind build	63.28	47.42

CANDU 6 LUEC Results - $/MW.h

	Merchant	Public
Base Case	88.64	63.44
20 years in Operation	91.99	70.69
40 years in Operation	88.82	61.38
85% capacity factor	93.63	66.95
95% capacity factor	84.17	60.30
Fuel Price - $0.50 lower, level	88.14	62.94
Fuel Price - $0.50 higher, level	89.14	63.94

Merchant Financing Sensitivities

	Coal	Gas	ACR-700	CANDU 6
Debt Rate 8%, Debt/Equity Ratio 50/50				
Equity Rate at 12%	59.33	75.35	73.33	88.64
Equity Rate at 13%	61.45	75.86	77.13	93.44
Equity Rate at 14%	63.59	76.39	81.01	98.35
Equity Rate at 15%	65.77	76.93	84.98	103.37
Equity Rate at 16%	67.97	77.49	89.02	108.49
Equity Rate at 17%	70.19	78.06	93.15	113.72
Equity Rate at 18%	72.44	78.65	97.36	119.04
Equity Rate at 19%	74.71	79.25	101.65	124.47
Equity Rate at 20%	77.01	79.86	106.02	130.00
Debt Rate 8%, Debt/Equity Ratio 70/30				
Equity Rate at 12%	56.15	74.17	67.29	80.99
Equity Rate at 13%	57.63	74.47	69.77	84.13
Equity Rate at 14%	59.10	74.77	72.25	87.26
Equity Rate at 15%	60.57	75.08	74.73	90.39
Equity Rate at 16%	62.04	75.39	77.20	93.53
Equity Rate at 17%	63.49	75.72	79.67	96.65
Equity Rate at 18%	64.95	76.05	82.15	99.78
Equity Rate at 19%	66.40	76.38	84.62	102.91
Equity Rate at 20%	67.84	76.73	87.10	106.04
Debt Rate 6%, Debt/Equity Ratio 50/50				
Equity Rate at 12%	57.45	74.72	69.27	83.49
Equity Rate at 13%	59.49	75.21	72.85	88.02
Equity Rate at 14%	61.55	75.72	76.51	92.66
Equity Rate at 15%	63.64	76.24	80.26	97.40
Equity Rate at 16%	65.76	76.78	84.09	102.25
Equity Rate at 17%	67.91	77.34	88.00	107.19
Equity Rate at 18%	70.08	77.91	91.99	112.24
Equity Rate at 19%	72.28	78.49	96.06	117.40
Equity Rate at 20%	74.51	79.08	100.21	122.65
Debt Rate 6%, Debt/Equity Ratio 70/30				
Equity Rate at 12%	53.63	73.31	62.02	74.32
Equity Rate at 13%	55.01	73.58	64.28	77.18
Equity Rate at 14%	56.39	73.85	66.55	80.04
Equity Rate at 15%	57.77	74.13	68.82	82.91
Equity Rate at 16%	59.14	74.43	71.09	85.79
Equity Rate at 17%	60.51	74.73	73.36	88.66
Equity Rate at 18%	61.89	75.04	75.64	91.54
Equity Rate at 19%	63.25	75.35	77.92	94.43
Equity Rate at 20%	64.62	75.68	80.21	97.33

Public Financing Sensitivities

	Coal	Gas	ACR-700	CANDU 6
Equity Rate at 6%	43.51	71.14	45.60	53.62
Equity Rate at 7%	45.55	71.57	49.32	58.34
Equity Rate at 8%	47.72	72.05	53.36	63.44
Equity Rate at 9%	50.02	72.58	57.70	68.94
Equity Rate at 10%	52.43	73.14	62.37	74.85
Equity Rate at 11%	54.97	73.75	67.35	81.15
Equity Rate at 12%	57.61	74.39	72.66	87.87

APPENDIX F: GLOSSARY OF KEY TERMS

Acid Rain: Precipitation containing harmful amounts of nitric and sulphuric acids formed primarily by nitrogen oxides and sulphur oxides released into the atmosphere when fossil fuels are burned.

AECL – Atomic Energy of Canada Limited: A nuclear technology and engineering company that designs and develops the CANDU nuclear power reactor, as well as other advanced energy products and services.

Allowance for Funds Used During Construction (AFUDC): (see Carrying Costs).

Annual Cash Flow: A series of annual net revenues (gross revenues minus direct costs), before depreciation and income taxes, accruing from the development and operation of a generating unit or plant.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter.

Ash: Impurities consisting of silica, iron, alumina, and other non-combustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, affects the burning characteristics of the coal, and lowers its calorific value. The disposal of ash from coal-fired generating plants after combustion is costly.

Baseload: The minimum amount of electric power delivered or required at a steady rate over a given period of time.

Baseload Capacity: The generating equipment normally operated to serve electricity demand on an around-the-clock basis.

Baseload Plant (or Unit): A generating plant or unit that is normally operated to take all or part of the minimum load of a power system, and which consequently produces electricity at an essentially constant rate and runs continuously.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent.

Boiler: A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature and quality.

British Thermal Unit: The standard unit of energy used in the United States. It equals 1.05506 kilojoules.

Calorific Value (Heat Content): The sum of latent heat and sensible heat contained in a combustible substance, above the heat contained at a specified temperature and pressure; expressed as joules per unit of volume or weight.

CANDU: Canadian Deuterium Uranium Reactor. A standardized design for nuclear generating stations developed in Canada. All nuclear generating units in Canada use the CANDU design.

Capability: The maximum load, in kilowatts or megawatts, that a generating unit, generating plant or other electrical equipment can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The maximum power capability of a generating unit in kilowatts or megawatts.

Capacity Factor: The ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period.

Capital Expenditures: The amount of capital used during a particular period to acquire or improve long-term assets such as a generating unit or plant or piece of equipment.

Carrying Costs: Allowance for funds used during construction (AFUDC) of a generating unit or plant. These are incurred from the time investment begins to the time the unit or plant goes into commercial operation.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, sub-bituminous coal and lignite, is based on fixed carbon, volatile matter and calorific value.

Cogeneration: The simultaneous generation of electricity and another form of useful thermal energy (e.g. heat or steam) from a single energy source (e.g. natural gas, biomass) used for industrial, commercial, heating or cooling purposes.

Combined Cycle Block: Electricity generating equipment that consists of one or more gas (combustion) turbines producing electricity and a heat recovery steam generator HRSG (or boiler), feeding a steam turbine-generator producing additional electricity. A portion of the required energy input to the HRSG is provided by the heat of the exhaust gas from the gas turbine(s).

Construction Period: The time, usually expressed in years, required to build a long-term asset such as an electric generation unit or plant. It is also the period over which carrying costs (or AFUDC) are incurred.

Conventional Generation: Electricity that is produced at a generating unit or plant where the prime movers are driven by a contained nuclear reaction or by the gases or steam produced by burning fossil fuels.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, and labour and other services.

Cost of Capital: The rate of return that a firm could earn from investments, other than a generating facility in question, with equivalent risks. It can also be stated as the *opportunity cost* of the funds used due to the investment decision.

Cost of Debt: The interest rate associated with borrowing money for investment.

Cost of Spent Fuel Storage and/or Disposal: The cost of storing and/or disposing of nuclear fuel that has been used in a nuclear reactor to the point where it can no longer produce economic power.

Debt/Equity Ratio: A measure of the risk of the firm's capital structure in terms of amounts of debt contributed by creditors and the amount of equity contributed by owners (shareholders). It expresses the protection provided by owners to the creditors. A low debt/equity ratio implies an ability to borrow. While using debt implies risk (required interest payments must be paid), it also offers the potential for increased returns to the firm's owners. When debt is used successfully (operating earnings exceed interest charges), the returns to shareholders are magnified through financial leverage.

Decommissioning: The act of taking a generating unit or plant out of service permanently. In the case of a nuclear plant this includes safely closing, and possibly dismantling (or otherwise disposing of), the existing facilities at the end of their service life.

Decommissioning Cost: The cost of the retirement of a nuclear unit or plant, including decontamination and/or dismantlement.

Depreciation or Amortization: The depreciation, depletion or charge-off to expense of intangible and tangible assets over a period of time.

Discounted Cash Flow: A calculation of the present value of a projected annual cash flow based on an assumed annual discounting rate, or rate of interest.

Economic Life: The time period of commercial operation of an asset that is assumed for the purpose of economic and/or financial evaluation of the asset.

Efficiency: The efficiency of a generating unit in converting the thermal energy contained in a fuel source to electrical energy. It is expressed as a percentage and equals 3.6 divided by the heat rate of the unit (in GJ/MW.h).

Electrical Energy: The quantity of electricity produced over a period of time. The commonly used units of electrical energy are the kilowatt-hour (kW.h), megawatt-hour (MW.h) and gigawatt-hour (GW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The typical basic units of electrical power are the kilowatt (kW) and megawatt (MW).

Emission: The release or discharge of a substance into the environment. It generally refers to the release of gases or particulates into the air.

Emission Cap: An upper limit placed on the emissions (usually airborne) from a polluting facility or from a group of all such facilities within a defined region.

Emissions Cost: The cost associated with the release or discharge of a substance into the environment; generally refers to the cost associated with the release of gases or particulates into the air.

Energy: The capability for doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks.

Equity: The sum of capital from a firm's retained earnings and the issuance of stocks.

Expenditure: The incurrence of a liability to obtain an asset or service.

External Benefits: Benefits that individuals, firms and society as a whole acquire, that they do not pay for directly in monetary terms, are said to be external benefits.

External Costs: Costs that individuals, firms and society as a whole bear, that are not paid or compensated for directly in monetary terms, are said to be external costs.

Externalities: Benefits or costs generated as a by-product of an economic activity, that do not accrue to the parties directly involved in the activity. Environmental externalities are benefits or costs that manifest themselves through changes in the physical or biological environment.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical and/or nuclear energy into electric energy are, or will be, situated. A facility may contain generating units of either the same or different prime mover types.

Fixed Operating Cost: The fixed portion of the cost associated with the annual operation and maintenance of a generating unit or plant. It is independent of the electrical energy produced. It is expressed in dollars per kilowatt per annum ($/kW.a).

Flue Gas: Gas resulting from the combustion of fuel, the calorific value of which has been substantially spent and discarded to the flue.

Flue Gas Desulphurization Unit (Scrubber): Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals (e.g. lime) are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, fabric filters (baghouses), mechanical collectors (cyclones) and wet scrubbers.

Fly Ash: Particle matter remaining after the combustion of coal, in which the particle diameter is less than 1×10^{-4} metre. It is substantially removed from the flue gas using particulate collectors such as electrostatic precipitators and fabric filters.

Forced Outage: The shutdown of a generating unit for emergency reasons, or a condition in which a generating unit is unavailable to supply electrical load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as coal, oil and natural gas.

Fossil-fuel Unit: A generating unit using coal, oil, gas or another fossil fuel as its source of energy.

Fuel: Any substance that can be burned to produce heat. It is also a material that can be fissioned in a nuclear reaction to produce heat.

Fuel Cost: That portion of the total variable cost of operating a generating plant or unit that is associated with the purchase and delivery of fuel used in the production of steam or driving another prime mover for the generation of electricity. It is usually expressed in dollars per megawatt-hour ($/MW.h).

Fuel Price: The price of fuel used in a generating unit, at the point of purchase. It is expressed here in dollars per gigajoule ($/GJ). In some cases, it is derived from the price of fuel expressed in dollars per unit of weight or volume (e.g. $/tonne of coal) and the corresponding calorific value (e.g. GJ/tonne).

Gas (or Combustion) Turbine: A generating unit in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to a turbine where the hot gases expand to drive a generator to produce electricity.

Generating Plant: A facility containing one or more generating units.

Generating Unit: Any combination of physically connected reactor(s), boiler(s), combustion turbine(s) or other prime mover(s), generator(s) and auxiliary equipment operated together to produce electricity.

Generation: The process of producing electrical energy by transforming other forms of energy.

Generator: A machine that converts mechanical energy into electrical energy.

Gigajoule (GJ): One billion joules.

Gigawatt (GW): One billion watts.

Gigawatt-hour (GW.h): One billion watt-hours.

Global Warming: The theoretical escalation of global temperatures caused by the increase of greenhouse gas concentrations in the lower atmosphere.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical transmission and/or distribution system.

Gross Generation: The electrical energy production of a generating plant or unit before subtracting station service, expressed in megawatt-hours (MW.h) or gigawatt-hours (GW.h).

Heat Content: (see Calorific Value).

Heat Rate: A measure of the efficiency of energy conversion of a generating unit or plant. It is the ratio of the heat content of the fuel used (expressed in kJ or Btu) in the unit or plant per kW.h of net electrical energy produced.

Income Tax Rate: A government levy on individuals as personal income tax and on the earnings of corporations as corporate income tax.

Inflation Rate: The annual rate at which the general level of prices for goods and services rises.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a plant, before deducting power requirements for station service.

Intermediate Load: The range of power system loads between baseload and peak load.

Intermittent Power Source: A generator, such as a wind turbine, whose output may vary considerably over short periods due to the variability and unpredictability of its external energy source.

Joule: The international unit of energy. It is the energy produced by the power of one watt operating for one second. At 100% efficiency, there are 3.6 megajoules in a kilowatt-hour (or 3.6 gigajoules in a megawatt-hour).

Kilowatt (kW): A standard unit used to measure electric power, equal to one thousand watts. A kilowatt can be visualized as the total amount of power required to light ten 100-watt bulbs.

Kilowatt-hour (kW.h): A standard unit for measuring electrical energy.

Least-cost Dispatch: The scheduling of power production as demand for electricity varies, according to the lowest-cost generation sources available to the operator of a power system, given transmission limits and other constraints.

Levelised Cost: The present value of the total cost of developing and operating a generating plant or unit over its economic life, converted to equal dollars per megawatt-hours of generation ($/MW.h).

Light Fuel Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum products used in internal combustion and gas turbines are light fuel oil.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter content

Load: The amount of electricity demand at any specific point or points on a power system. The amount originates at the energy-using equipment of consumers.

Load Factor: The ratio of the average electricity demand over a designated period of time to the peak demand occurring during the same period.

Load Following: An ancillary service that adjusts generation to meet the hour-to-hour and daily load variations between generators and demands.

Long-run Marginal Cost (LRMC): The total cost of developing and operating facilities including both total fixed and total variable costs. Here, it is the same as Levelised Cost.

Megawatt (MW): One million watts.

Megawatt-hour (MW.h): One million watt-hours.

Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment, under specific conditions as designated by the manufacturer. Installed nameplate rating is usually indicated on a nameplate physically attached to the piece of equipment.

Natural Gas: A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane. It is used as a fuel in boilers and gas turbines for electricity generation.

Net Capability: The maximum ability of a generating unit or plant, under specified conditions, to meet electricity demand. It is the capability of the generating equipment minus station service. It is usually expressed in megawatts (MW).

Net Generation: Gross generation of a generating unit or plant minus station service, expressed in megawatt-hours (MW.h) or gigawatt-hours (GW.h).

Net Present Value (NPV): A method used to evaluate an investment, whereby the *present value* of all revenues less the *present value* all expenditures, including capital cost, fixed and variable operating costs, and fuel costs, associated with the investment, are calculated using a given discount rate. The investment is acceptable if the NPV is positive.

Nominal Dollars: Value of currency expressed as dollars of the day, i.e. not inflation adjusted. Also referred to as 'current' dollars.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A generating plant in which heat produced in a nuclear reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Nuclear Reactor: A device in which a fission chain reaction can be initiated, maintained and controlled. Nuclear reactors are used in the power industry to produce steam used for the generation of electricity.

Overnight Capital Cost: The total capital expenditures required to develop a generating plant or unit, before adding carrying charges.

Peak Load Plant (or Unit): A generating plant (or unit) that normally operates intermittently during the hours of highest (peak) daily, weekly or seasonal power system loads.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during peak load periods.

Planned Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Power: The rate at which energy is produced. Electrical energy is usually measured in watts.

Power System: All the physically interconnected facilities of an electrical utility, or a number of interconnected utilities. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to consumers.

Present Value: The value of a revenue acquired or an expenditure incurred in the future, expressed in terms of its current value, taking into consideration the time value of money. Present value equals future value divided by one plus interest rate, all raised to the power of the number of years into the future. Here, the interest rate used represents the return on investment.

Price: The amount of money or consideration-in-kind for which a good or service is bought, sold or offered for sale.

Prime Mover: The engine, turbine, water wheel or similar machine that drives an electric generator.

Profit: The income remaining after all business expenses are paid.

Rate of Return: The gain or loss for a security in a particular period, consisting of income plus capital gains relative to investment, usually quoted as a percentage. The real rate of return is the annual return realized on that investment, adjusted for changes in price due to inflation.

Real Dollars: Value of a currency expressed in inflation-adjusted terms and referenced to a base year. Also known as 'constant' dollars.

Return on Equity (ROE): Measures the overall efficiency of the firm in managing its total investments in assets and in generating a return to stockholders. It is the primary measure of how well management is running the company.

Return on Investment (ROI): ROI can be calculated in various ways. The most common method is Net Income as a percentage of Net Book Value (total assets minus intangible assets and liabilities).

Revenue: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owners' equity except those arising from capital adjustments.

Scrubber: (See Flue Gas Desulphurization Unit).

Separate Work Unit (SWU): A standard measure of uranium enrichment services.

Short-run Marginal Cost (SRMC): Variable cost of production that does not carry long-term or capital implications. Here it equals variable operating cost plus fuel cost. It is the same as total variable cost.

Spent Fuel: Nuclear fuel removed from a reactor following irradiation, which is no longer usable in its current form because of depletion of fissile material, poison build-up or radiation damage.

Station Service: The electric energy used in the operation of a generating plant or unit. This energy is subtracted from the gross generation to obtain net generation.

Steam-electric Unit: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is generated in a boiler where fossil fuels are burned, or by heat produced in a nuclear reactor by the fissioning of nuclear fuel.

Sub-bituminous Coal: Sub-bituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture.

Sunk Cost: A cost that was incurred in the past and cannot be altered by any current or future decision.

Thermal Efficiency: The percentage of total energy content of a fuel that is converted to useful output. The ratio of useful work (or energy output) to total work (or energy input).

Total Fixed Cost: Expenses that are incurred to provide facilities and organization that are kept in readiness to do business without regard to actual volumes of production and sales. Here, total fixed costs comprise the capital charges and fixed operating costs of a generating plant or unit. They are incurred regardless of the amount of electrical energy produced. They are expressed in dollars per kilowatt per annum ($/kW.a).

Total Variable Costs: Expenses incurred in the operation of a generating plant or unit that depend on the amount of electrical energy produced. Here, total variable costs comprise variable operating costs plus fuel costs. They are expressed in dollars per megawatt-hour ($/MW.h).

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse or reaction, or a mixture of the two.

Unit (or Plant) Availability: The number of hours a generating unit is available to produce power (regardless of the amount of power) in a given period, compared to the number of hours in the period.

Variable Operating Cost: The variable portion of the cost associated with the operation and maintenance of a generating unit or plant. It is dependent on the amount of electrical energy produced. It is expressed in dollars per kilowatt per annum ($/MW.h).

Watt: The standard unit of electrical power. One watt is equal to one joule per second. It also equals one ampere flowing under a pressure of one volt at unit power factor.

Watt-hour (W.h): The standard unit of electrical energy. It is equal to one watt of power operating steadily for one hour.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain security of service and power quality at the transmission level.

Wholesale Price: The price of energy supplied to electric utilities and other power producers.

Wind Generator: A generator that obtains its power from wind turning a wind turbine.

Acronyms and Abbreviations

ACR	Advanced CANDU reactor
AECL	Atomic Energy of Canada Limited
Btu	British thermal unit
CANDU	Canada Deuterium Uranium
CC	Combined cycle
CCGT	Combined cycle gas turbine
CNA	Canadian Nuclear Agency
CO_2	Carbon dioxide
DCF	Discounted cash flow
EIA	Energy Information Administration of the U.S. Department of Energy
FGD	Flue gas desulphurization
G	Billion
GJ	Gigajoule
GT	Gas (combustion) turbine
GW	Gigawatt
GW.h	Gigawatt-hour
HRSG	Heat recovery steam generator
IEA	International Energy Agency of the Organization for Economic Cooperation and Development (OECD)
IGCC	Integrated gasification combined cycle
k	Thousand
kW	Kilowatt
kW.h	Kilowatt-hour
LRMC	Long-run marginal cost
LUEC	Levelised unit cost of electricity
M	Million
MIT	Massachusetts Institute of Technology
MW	Megawatt
MWe	Megawatts electric
MW.h	Megawatt-hour
NEA	Nuclear Energy Agency of the Organization for Economic Cooperation and Development (OECD)
NO_x	Oxides of nitrogen
NPV	Net present value
NRC	Nuclear Regulatory Commission (US)
O&M	Operation and maintenance
PV	Present value
ROE	Return on equity
ROI	Return on investment
SO_x	Oxides of sulphur

ST	Steam turbine
SWU	Separate work unit
U	Uranium
USDOE	United States Department of Energy

International System of Units (SI) Prefixes

Prefix	Multiplication Factor
kilo (k)	10^3
Mega (M)	10^6
Giga (G)	10^9
Tera (G)	10^{12}

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