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Report: NGD-10 (1983)
Class: Unclassified
Date: March 1984

Authors: H.A. Jackson
L.W. Woodhead
G.R. Fanjoy
CNS/RMEP Staff

Nuclear Generation Division

ECONOMICS OF CANDU-PHW

ontario hydro

March 1984

NGD--10(1983).

ECONOMICS OF CANDU-PHW

BY

H.A. JACKSON

L.W. WOODHEAD

G.R. FANJOY

ONTARIO HYDRO*

Abstract

The CANDU-Pressurized Heavy Water (CANDU-PHW) type of nuclear-electric generating station has been developed jointly by Atomic Energy of Canada Limited and Ontario Hydro. This paper discusses the cost of producing electricity from CANDU, presents actual cost experience of CANDU and coal in Ontario, presents projected CANDU and coal costs in Ontario and compares CANDU and Light Water Reactor cost estimates in Ontario.

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*Staff contact for all enquiries - I. Jumis.

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0.0 INTRODUCTION

The purpose of this paper is to:

- Discuss the cost of producing electricity from CANDU-Pressurized Heavy Water (PHW) nuclear generating units.
- Present actual cost experience of CANDU units in Ontario Hydro.
- Compare CANDU cost experience with fossil (coal) experience in Ontario Hydro.
- Present projected CANDU and fossil cost data in Ontario Hydro.
- Present cost estimate comparisons of CANDU and Light Water Reactors (LWR) in Ontario Hydro.

1.0 COST CRITERIA

The Cost Objective of Ontario Hydro is to produce and deliver electricity at the lowest long-term cost to Ontario customers, while satisfying the other rudimentary objectives:

- Worker Safety
- Public Safety
- Environmental Protection
- Reliability

If a comparison is made between two alternative types of generation, the degree to which all of those objectives are satisfied should be considered.

A comprehensive discussion of the CANDU-PHW type nuclear unit, including Worker Safety Experience, Public Safety Experience, Environmental Protection Experience and Reliability Experience, has been reported by the authors in a companion paper, Ontario Hydro CANDU OPERATING EXPERIENCE (NGD-9-1983).

The load of Ontario Hydro (as with most electrical utilities) varies with time. Loads peak in the daytime, Monday to Friday when factories are busy and society is active. In Ontario, the loads are higher during the winter when temperatures are low.

The most economical generating system for Ontario Hydro is a mix of hydraulic generation, fossil generation and nuclear generation.

The majority of available economic hydraulic resources in Ontario have been developed. New loads must be met by alternative resources of which nuclear and coal are the primary options for the balance of this century.

The Ontario Hydro system Load Factor is typically 64.6% (the ratio of average annual power to peak annual power). Fossil-fired generation is most economical for peak load requirements because of its lower Capital and Operating, Maintenance and Administrative (OM&A) Costs. Nuclear generation is most economical for base load application because its higher Capital and OM&A Costs are more than offset by the very low Fueling Costs.

This paper is limited to a cost discussion for base load generation in Ontario Hydro.

Cost evaluations for generation commitment decisions of Ontario Hydro are very complex, utilizing present value techniques, uncertainty analyses, load forecasts, reliability assessments, environmental impacts, etc, that are beyond the scope of this paper.

The Total Unit Energy Cost (TUEC) method is a simple and accurate indicator of the relative economics for base load application and is used in this paper. The production reliability and Total Unit Energy Cost information presented in this paper are based on the sum of electrical energy plus electrical equivalent steam production.

Total Unit Energy Cost (TUEC)

The cost of producing energy from generating stations involves the following cost classifications:

- The research and development of generation concepts.
- The cost of building the stations.
- The cost of operating and maintaining the stations.
- The cost of fueling the stations.
- The cost of in service modifications.

- The cost and benefits associated with disposal of the stations at the end of their useful life.

- Overhead costs to support the above cost classifications.

In addition, the cost of producing energy must also consider:

- The method employed for financing and amortizing the investments.

- The interest rates applicable to the above classifications.

- The lifetime assumed for the facilities.

- The reliability of the stations to produce energy.

- The policies that are adopted concerning source of supply, taxes, regulations, etc.

The Total Unit Energy Cost (TUEC) is defined as the total annual cost of producing energy (dollars) divided by the total annual energy produced (kilowatt-hours electrical equivalent).

$$\text{TUEC} = \frac{\text{Total Annual Cost}}{\text{Total Annual Energy Produced}}$$

In this paper, the research required to develop the generation concepts is excluded. In the opinion of the authors, this exclusion does not have a serious effect on the absolute costs and relative costs of the generation alternatives, in the long-term, for a major program.

The four cost components for the CANDU-PHW concept are:

1. Annual Interest, Depreciation and Decommissioning Cost
2. Annual Operation, Maintenance and Administration Cost
3. Annual Fueling Cost
4. Annual Heavy Water Upkeep Cost

The three cost components for the Light Water Reactor (LWR) concept and coal-fired stations are:

1. Annual Interest, Depreciation and Decommissioning* Cost
2. Annual Operation, Maintenance and Administration Cost
3. Annual Fueling Cost

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* Nuclear Only

The computation of the Annual Interest, Depreciation and Decommissioning Cost depends upon five factors:

1. The Initial Capital Cost and the Capital Modifications Cost
2. The Interest Rate
3. The Lifetime of the Station
4. The Method of Amortization of the Initial Capital Cost and the Capital Modifications Cost
5. The Provision for Future Decommissioning Cost

The Initial Capital Cost includes:

1. The Design and Engineering Cost
2. The Construction Cost
3. The Commissioning Cost
4. The Permanent In-Reactor Fuel Charge
5. The Heavy Water Inventory
6. Overheads
7. Accumulated Compound Interest During Construction
8. Capitalized Training Cost

The Initial Capital Cost includes the Permanent In-Reactor Fuel Charge (one-half of the Initial Fuel Charge) and the Heavy Water Inventory. The Initial "Dry" Capital Cost is identical to the Initial Capital Cost except that the Permanent In-Reactor Fuel Charge, the Heavy Water Inventory, Commissioning and Capitalized Training are excluded.

The Provision for future Decommissioning Cost is not a cost of production that has been incurred to date. It is a provision for the estimated future cost of decommissioning a station at the end of its useful life. The provision is determined using the sinking fund approach which matches the accumulated annual provisions together with compound interest to the forecast future cost of decommissioning.

The Annual Operation, Maintenance and Administration Cost includes:

1. Labour
2. Materials
3. Purchased Services
4. Interest on Operating and Maintenance Inventories
5. Overheads (including taxes)

The Annual Fueling Cost includes:

1. Fuel (quantity and price)
2. Interest on Inventory
3. Transportation
4. Overheads
5. Provision for Future Irradiated Fuel Transportation, Storage, and Disposal

The Provision for Future Irradiated Fuel Transportation, Storage, and Disposal is not a cost of production that has been incurred to date. It is a provision for the estimated future costs of transportation, storage, and disposal of irradiated nuclear fuel. The provision is determined using the sinking fund approach which matches the accumulated annual provision together with compound interest to the future cost of fuel transportation, storage, and disposal. The current forecast includes no credit for the potentially valuable contained isotopes (eg, plutonium).

The Annual Heavy Water Upkeep Cost is comprised of two basic factors:

1. The cost of replacing any heavy water lost during operation.

2. The cost of upgrading any heavy water which becomes downgraded during operation (diluted with ordinary water).

The Total Unit Energy Cost (TUEC) is the sum of the Unit Energy Cost (UEC) for each of the cost components. As an example, the Fueling Unit Energy Cost (FUEC) is as follows:

$$FUEC = \frac{\text{Fueling Annual Cost}}{\text{Total Annual Energy Produced}}$$

The Total Unit Energy Cost (TUEC) is very dependent on the Capacity Factor* achieved.

The Total Annual Energy used to determine TUEC may be either the gross or net energy produced. Ontario Hydro prefers to use net energy - TUEC (net). However, for some utilities, only the gross production is published and TUEC (gross) is determined.

The Specific Capital Cost is the Total Initial Capital Cost ($) divided by the Net Capacity (kW) and is expressed in dollars per kilowatt.

All costs expressed in this paper are in Canadian dollars.

The intent of this report is to present and compare cost information for energy generation types on a consistent and comparable basis (ie, the same cost definitions are used for coal, CANDU, and LWR). Therefore the treatment of capital costs differs to some extent from that used to allocate costs to Ontario Hydro customers. These differences do not affect the judgment or conclusions made.

$$\text{*Capacity Factor} = \frac{\text{Actual Energy Produced}}{\text{Perfect Production}}$$

for any specified period.

2.0 ONTARIO HYDRO COST COMPARISON
CANDU-PHW VERSUS FOSSIL (COAL)

The cost comparison between CANDU-PHW units and alternative sources of generation will depend upon many factors which are particular to the electrical utility making the comparison.

Nuclear fuel cost tends to be independent of the distance between the uranium source and the generating station because transport cost of nuclear fuel is small. In the case of coal, the transport cost is low if the generating unit is near the coal mine, but can be very high if the coal has to be transported a great distance.

The following data illustrates that the CANDU-PHW is very competitive within Ontario Hydro where economic hydro-electric resources have been almost fully developed and where coal must be transported a minimum of 800 kilometres. There are other locations in Canada in which coal-fired generation is cheaper than CANDU-PHW where the generating unit is near the mine. The high current and projected cost of oil and gas makes their use uneconomical for base load generation in Ontario Hydro.

More specifically, the following presentation compares the Ontario Hydro Pickering Nuclear Generating Station-A (PNGS-A) with the Ontario Hydro Lambton Thermal Generating Station (TGS). The Pickering NGS-A comprises four 515 MWe (net) nuclear units of the CANDU-PHW type. The Lambton TGS comprises four 495 MWe (net) units which burn coal. Both stations were built at the same time, both are of modern design and both stations are fully operational with good performance records.

For the year 1983, Pickering NGS-A had a Net Capacity Factor of 75.9%. Table 1 illustrates the Unit Energy Costs (UEC) of these two stations.

The following should be noted from Table 1:

- The coal-fired Capital Cost is much lower than the nuclear Capital Cost.

- The coal-fired OM&A Cost is lower than the nuclear OM&A Cost.

- The nuclear Fueling Cost is very much lower than the coal-fired Fueling Cost.

- The Heavy Water Upkeep Cost, which applies only to the nuclear, is only a small percentage (about 4%) of the Total Unit Energy Cost.

Table 1

Pickering NGS-A/Lambton TGS Cost Comparison - 1983

Pickering NGS-A and Lambton TGS Net Capacity Factor: 75.9%*

	UEC [m$/kW.he (net)]	
	Pickering NGS-A	Lambton TGS
Interest, Depreciation and Decommissioning	7.72	1.99
Operation, Maintenance, and Administration	6.15	2.23
Fueling	3.79	21.80
Heavy Water Upkeep	0.78	
Total Unit Energy Cost (Net)	18.44	26.02

Station Data

	Pickering NGS-A	Lambton TGS
Capacity (Maximum Continuous Rating) MWe net	4 x 515	4 x 495
In Service	1971 - 1973	1969 - 1970
Initial Capital Cost (M$ Canadian escalated)	746.5	257.0
Specific Capital Cost ($/kWe)	362.4	129.8
Economic Lifetime (years)	40	35
Depreciation Method	Straight Line	Straight Line
Interest Rate (%)	11.9	11.9

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*Assumes Lambton TGS also operated at base load with Net Capacity Factor of 75.9%. Lambton TGS actual 1983 Net Capacity Factor was 63.6%.

- For base load application, Pickering NGS-A had less than 3/4 the Total Unit Energy Cost of Lambton TGS in 1983.

During the period up to 1983, in service capital modifications have been made to both Pickering NGS-A and Lambton TGS. These modifications are amortized on a remaining lifetime basis and are included in the comparison.

It is expected that further capital modifications will be required from time to time to replace major components and meet new requirements.

For example, Lambton TGS may have to be retrofitted with SO_2 scrubbers to meet acid rain requirements, and the pressure tubes at Pickering Units 1 and 2 will be replaced.

Figure 1 presents the Pickering NGS-A versus Lambton TGS Unit Energy Costs (assuming Lambton TGS operated at the same high Capacity Factors as Pickering NGS-A) for each year from 1975 to 1983 inclusive.

Ontario Hydro started making provision for future decommissioning and future irradiated fuel transportation, storage, and disposal costs for nuclear stations in January 1982. Consequently, these costs are only in the 1982 and 1983 nuclear data. Such costs are not included explicitly for nuclear prior to 1982, nor for coal stations for any year.

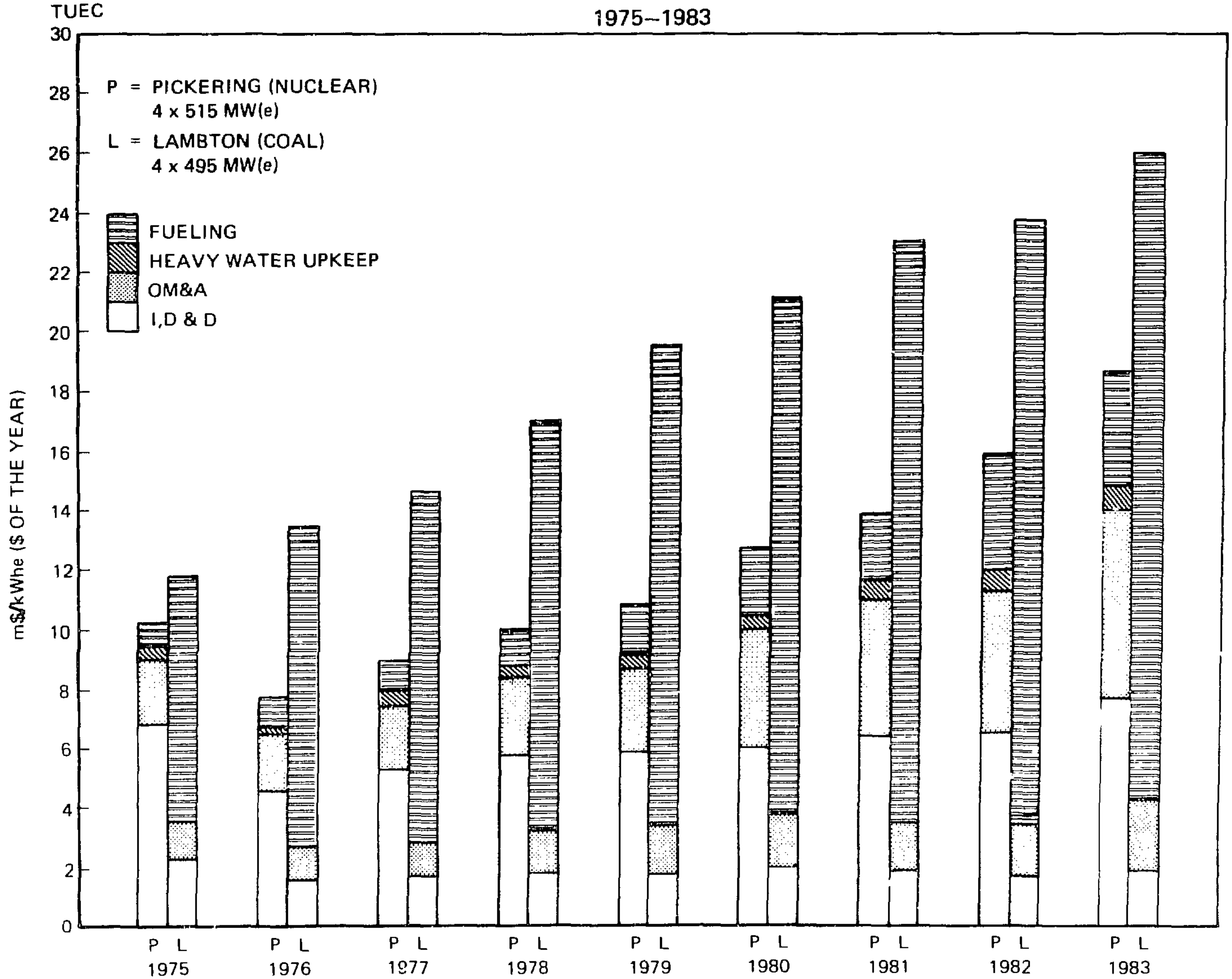
The actual costs included in the 1983 Pickering NGS data are:

	Unit Energy Cost (m$/kW.he)
Provision for Future Decommissioning	.40
Provision for Future Irradiated Fuel Transportation, Storage, and Disposal	1.16

This graph clearly shows the cost advantage of the nuclear plant. This is an example of the "inflation-proof" characteristics of the CANDU-PHW.

This graph also shows that the cost of Heavy Water Upkeep is only a small component (about 4%) of the Total Unit Energy Cost.

FIGURE 1
TOTAL UNIT ENERGY COST COMPONENTS
THERMAL VERSUS NUCLEAR
1975–1983



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Highlight

The base load cost (TUEC) of the Pickering NGS-A has been consistently well below the cost of the Lambton TGS (coal-fired) since 1975.

This cost advantage is expected to increase as fossil fuels become more expensive.

3.0 CANDU COSTS VERSUS TIME

The actual or estimated TUEC for in service stations and stations under construction will vary with time due to a variety of reasons including:

- Escalation of labour and material costs.
- Changes in interest rates.
- Escalation of fuel costs.
- Changes in design and operating requirements.
- Changes in operating performance.
- Competence and maturity of workforces (design, manufacturing, construction, operation).

The Pickering NGS-A and the Lambton TGS were built in the late 1960s and placed in service in the early 1970s.

During the 1970s, high inflation caused Capital, OM&A and Fueling Costs to be driven rapidly upwards.

As a result, new coal-fired generating stations such as Nanticoke TGS (8 x 490 MWe net) and new nuclear stations such as Bruce NGS-A (4 x 775 MW ee* net) have higher Capital Costs.

In addition, the TUEC of the in service coal-fired station, Lambton TGS (4 x 495 MWe) and the in service nuclear station, Pickering NGS-A (4 x 515 MWe), are rising due to inflation in OM&A and Fueling Costs.

The Specific Capital Cost of Bruce NGS-A compared with the Specific Capital Cost of Pickering NGS-A is affected by three major factors:

- Bruce NGS-A has lower costs due to larger unit size.
- Bruce NGS-A has higher costs due to new regulatory requirements.
- Bruce NGS-A has much higher costs due to inflation of labour and materials.

The result is that the Pickering NGS-A Specific Capital Cost was 362.4$/kWe (net) and Bruce NGS-A was 632.6$/kWee (net).

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*Electrical equivalent energy including steam and electrical generation.

Pickering NGS-A came into service between 1971 and 1973, while Bruce NGS-A came into service between 1977 and 1979.

Table 2 compares Bruce NGS-A Unit Energy Costs with Nanticoke TGS Unit Energy Costs in 1983, assuming Nanticoke operated with the same high Capacity Factors as Bruce NGS-A.

Figure 2 presents the Bruce NGS-A versus Nanticoke TGS Unit Energy Costs (assuming Nanticoke operated at the same high Capacity Factors as Bruce NGS-A) for each year from 1977 to 1983.

Ontario Hydro started making provision for future decommissioning and future irradiated fuel transportation, storage, and disposal costs for nuclear stations in January 1982. Consequently, these costs are only in the 1982 and 1983 nuclear data. Such costs are not included explicitly for nuclear prior to 1982, nor for coal stations for any year.

The actual costs included in the 1983 Bruce NGS-A data are:

	Unit Energy Cost (m$/kW.hee)
Provision for Future Decommissioning Cost	0.22
Provision for Future Irradiated Fuel Transportation, Storage, and Disposal	0.85

Figure 2 shows that while the Total Unit Energy Cost for Nanticoke (coal) was close to Bruce NGS-A (nuclear) in 1977 and 1978, in each subsequent year, the nuclear station had a significant cost advantage.

Table 2

Bruce NGS-A/Nanticoke TGS Cost Comparison 1983

Bruce NGS-A and Nanticoke TGS Net Station Capacity Factor: 89.9%*

	UEC [m$/kW.hee (net)]	
	Bruce NGS-A	Nanticoke TGS
Interest, Depreciation and Decommissioning	9.92	3.38
Operation, Maintenance, and Administration	3.85	1.46
Fueling	4.18	25.83
Heavy Water Upkeep	0.42	-
Total Unit Energy Cost (Net)	18.37	30.67

Station Data

	Bruce NGS-A	Nanticoke TGS
Capacity (Maximum Continuous Rating) MWee net	4 x 775**	8 x 490
In Service	1977 - 1979	1973 - 1978
Original Capital Cost (M$ Canadian escalated)	1 961.1	872.9
Specific Capital Cost ($/kWee)	632.6	216.1
Economic Lifetime (years)	40	35
Depreciation Method	Straight Line	Straight Line
Interest Rate (%)	11.9	11.9

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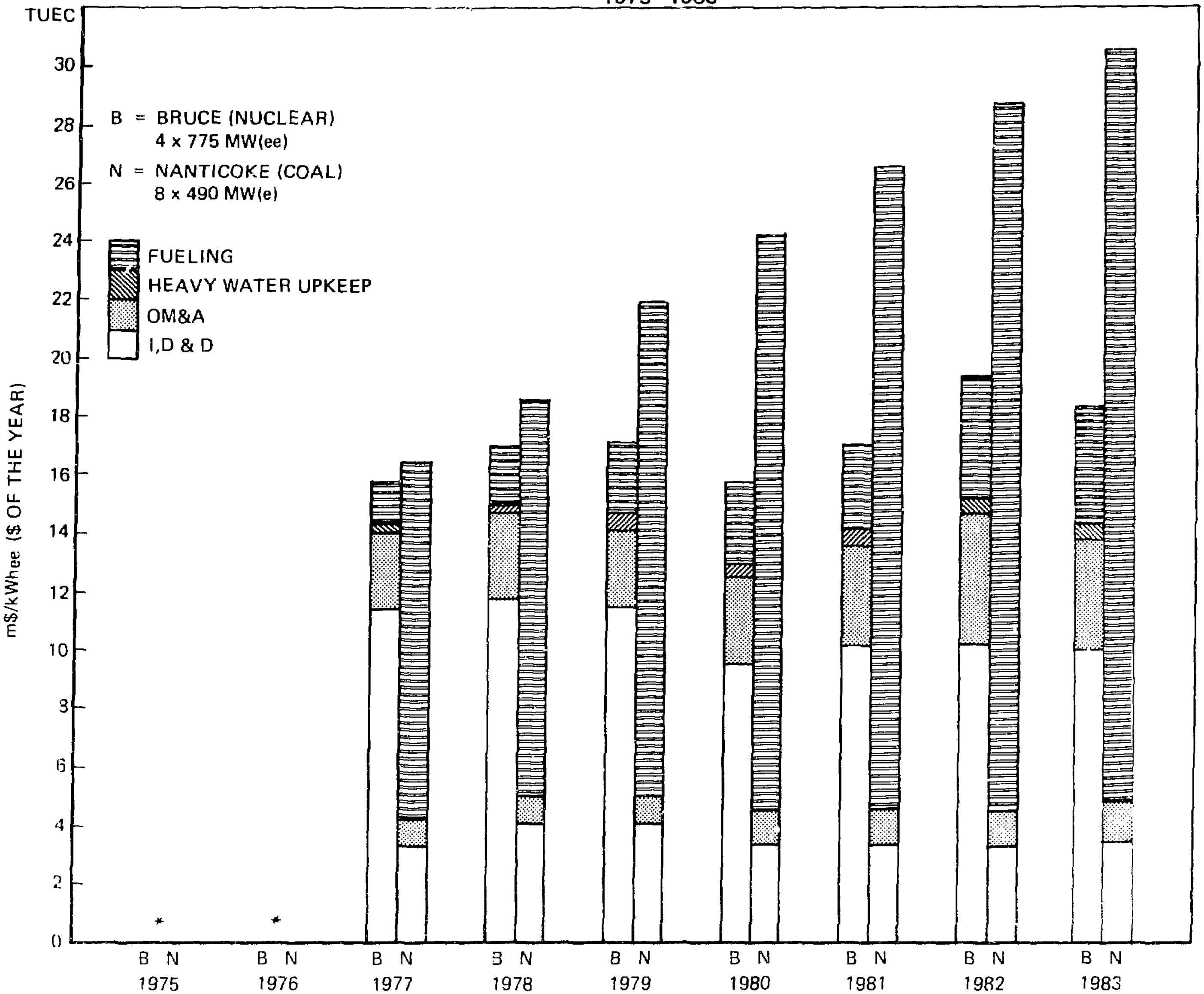
* Assumes Nanticoke TGS also operated as a base loaded station with a Net Capacity Factor of 89.9%. Nanticoke TGS actual 1983 Net Capacity Factor was 52.6%.

**Includes 35 MWee steam per unit produced over and above the turbine/generator capabilities of the unit.

FIGURE 2
TOTAL UNIT ENERGY COST COMPONENTS
THERMAL VERSUS NUCLEAR
1975–1983



*BRUCE NGS-A WENT INTO SERVICE FROM 1977 to 1979

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4.0 ONTARIO HYDRO COST PROJECTIONS

The CANDU-PHW at Pickering NGS-A and Bruce NGS-A has demonstrated a major cost advantage for base loaded application in Ontario Hydro in the 1970s. The TUEC has been projected for CANDU-PHW and coal-fired stations for the period from 1984 to 2002. These projections exclude the possible retrofit of SO_2 scrubbers in coal-fired stations and exclude possible major retrofits in nuclear stations such as pressure tube replacement. These projections also exclude the cost of replacing the pressure tubes in Pickering Units 1 and 2 as a result of the failure of the Zircaloy-2 pressure tube in Unit 2 on August 1, 1983.

Figure 3 displays the actual and forecast TUEC for base load application of four stations currently in service (assuming Ontario Hydro escalation forecasts of labour and materials).

Coal-Fired - Lambton TGS (4 x 495 MWe)
- Nanticoke TGS (8 x 490 MWe)

CANDU-PHW - Pickering NGS-A (4 x 515 MWe)
- Bruce NGS-A (4 x 775 MWee)

These projections indicate:

- That the base load advantage of CANDU-PHW is expected to continue.

- That the base load advantage of CANDU-PHW is expected to increase with time.

- The "inflation-proof" characteristic of CANDU-PHW.

Table 3 presents the actual Initial Capital Cost of Pickering NGS-A and Bruce NGS-A together with the estimated costs of three nuclear stations under construction -- Pickering NGS-B, Bruce NGS-B and Darlington NGS.

FIGURE 3
TOTAL UNIT ENERGY COST
FOR MAJOR OPERATING NUCLEAR
AND THERMAL STATIONS

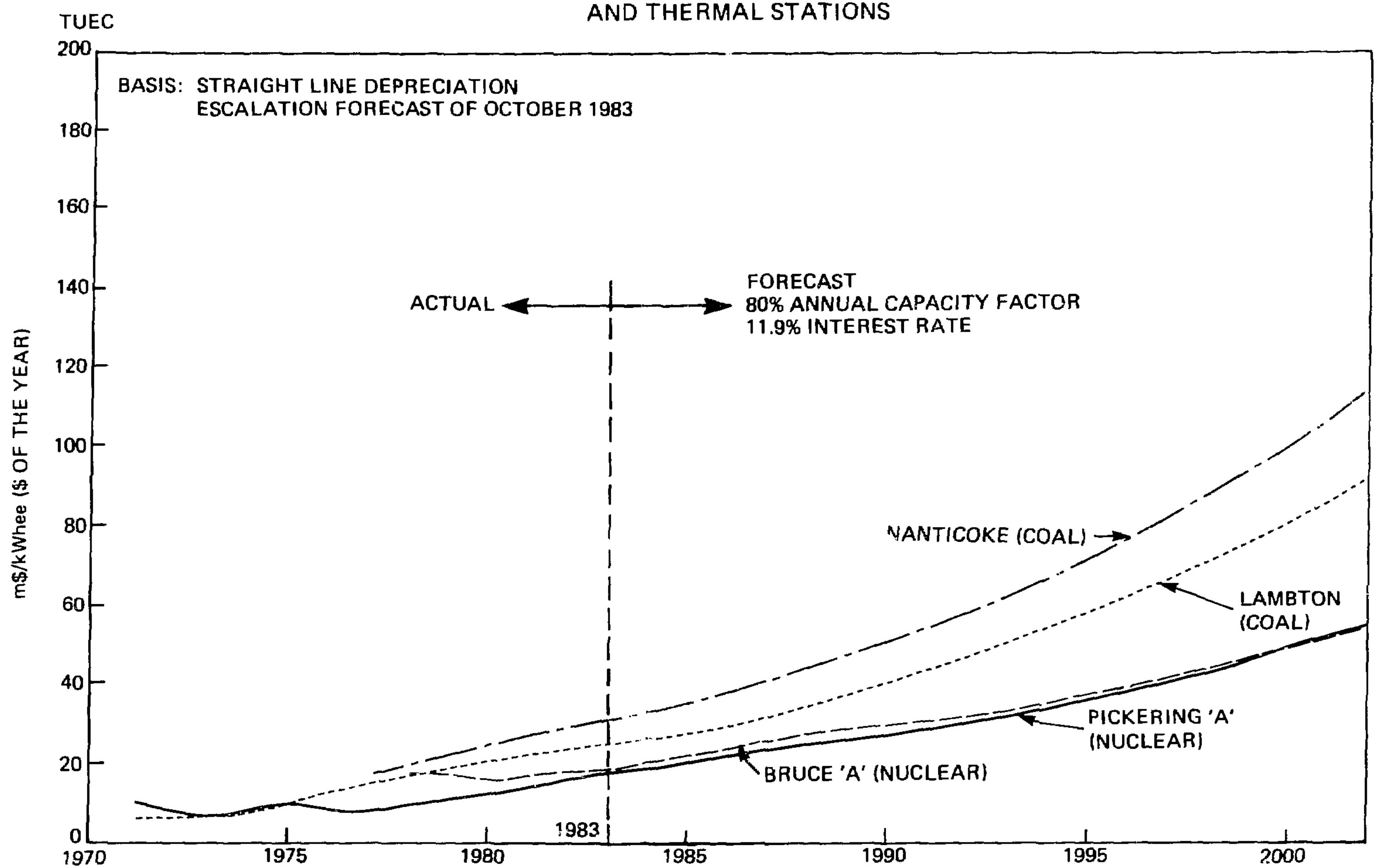

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Table 3

Nuclear Capital Cost Data
($ of the year)

Actual

Station	Net Capacity MW ee	Initial Capital Cost M$	Specific Cost $/kWee	Dry* Capital Cost M$	Specific Dry* Capital Cost $/kWee	Year In Service
Pickering NGS-A	2 060	746.5	362.4	565.7	274.6	1971-1973
Bruce NGS-A	3 100	1 961.1	632.6	1 498.9	483.5	1977-1979

Estimated (as at December 31, 1983)

Station	Net Capacity MW ee	Initial Capital Cost M$	Specific Cost $/kWee	Dry* Capital Cost M$	Specific Dry* Capital Cost $/kWee	Year In Service
Pickering NGS-B	2 064	3 806.0	1 844.0	2 874.2	1 392.5	1983-1985
Bruce NGS-B	3 000	6 187.5	2 062.5	4 519.2	1 506.4	1984-1987
Darlington NGS	3 524	11 404.0	3 236.1	8 676.2	2 462.0	1988-1992

*Dry capital costs exclude heavy water, fuel, commissioning and training.

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5.0 FACTORS TO BE CONSIDERED FOR INTER-UTILITY AND CONCEPT COST COMPARISONS

Relevant and meaningful comparisons of cost experience using data from two or more utilities demand a very objective and rigorous analysis.

The following are some of the factors which should be considered:

Unit Size

- Larger units will tend to have lower Specific Capital Costs ($/kWe) and lower Specific OM&A Costs ($/kWe).
- Larger units will tend to have lower Capacity Factor Performance for the same vintage and technology.

Units Per Station

- Increased number of identical units will tend to have lower Specific Capital Costs and lower Specific OM&A Costs.
- Increased number of identical units will tend to have higher Capacity Factor Performance.

Schedule Upsets

- Generating stations that suffer schedule delay because of program changes or because of major problems in executing the project will tend to have higher Specific Capital Costs due to higher interest during construction and re-scheduling costs.

Concept Maturity

- A well developed and proven concept will tend to enjoy lower costs and higher performance. Promising new concepts will require tolerance while maturing.

Utility Maturity

- Independent of concept maturity, each utility adopting the concept must go through a learning process during which costs and performance will suffer.

Designer Maturity

- Independent of concept maturity and utility maturity, the cost and performance will depend upon the maturity of the designers.

Supply Industry Maturity

- The cost and performance will depend, in part, on the composite capability of the many suppliers of station components.

Supply Industry Volume

- The cost of a station will depend, in part, on the throughput volume of supply industries.

Project Management Efficiency

- Nuclear station costs depend not only on the maturity of the individual project members, but also on the overall efficiency of the project members working as a team. New teams will tend to have higher costs.

Industry Management Efficiency

- The cost of designing and manufacturing components in a given nation will depend, in part, on the general industrial capability and labour stability of that nation.

Labour Costs

- Nations with lower labour costs will tend to have lower costs assuming similar industrial efficiency.

Operating Staff Maturity

- A rapidly expanding nuclear program increases costs and reduces performance due to less than optimum operating experience.

Operations Management Efficiency

- Some utilities will enjoy better management systems to reduce problems and respond to problems more effectively.

Research and Development Efficiency

- The ready availability of research and development capability will enhance design and facilitate problem solving during design and operation.

Regulatory Efficiency

- A regulatory authority with good judgment and ability will enhance the achievement of objectives including schedule and cost. Immature or incompetent regulatory authorities will cause schedule delays with attendant cost penalties.

General Society Behaviour

- Where a concept has been generally endorsed by society, the cost of building and operating a nuclear station will tend to be reduced.

Foreign Exchange Rates

- Comparisons between utilities in different countries require conversion from one currency to another. The relationship between currencies can change dramatically over a period of a few years.

Supply Policies

- Costs and performance will depend, in part, on supply policies. For example, a policy to utilize domestic sources may increase cost.

In view of the above factors, precise conclusions from comparisons between nuclear concepts are difficult, if not impossible, to make. Nevertheless, the authors have attempted to recognize these factors in the following comparison applicable to Ontario. The conclusions could be quite different for alternative assumptions and conditions in another location in Canada or a different country.

6.0 ONTARIO HYDRO COST COMPARISON -- CANDU-PHW VERSUS LIGHT WATER REACTORS (LWR)

The Ontario Hydro nuclear program, to date, has been limited to experience with CANDU-PHW units. Ontario Hydro has exchanged cost information and operating performance with other utilities in the USA, Europe and Asia. In particular, this information applied to alternative nuclear types -- Light Water Reactors (LWR) and Gas-Cooled Reactors (GCR).

Ontario Hydro is continuing to observe the world progress on Fast Breeder Reactors (FBR).

At the present time, the LWR is the only viable nuclear alternative to CANDU-PHW in Ontario Hydro.

The LWR has two basic options -- the Pressurized Water Reactor (PWR) and the Boiling Water Reactor (BWR).

Inasmuch as Ontario Hydro has had no design and operating experience with LWR, the cost comparisons between CANDU-PHW and LWR must be based upon the following:

- Comparison of costs reported by other utilities for LWR with Ontario Hydro costs for CANDU-PHW.

- Estimates of CANDU-PHW and LWR assumed to be built in Ontario under Canadian licensing requirements.

The judgments expressed below are those of the authors and are based upon the following:

- The detailed insight Ontario Hydro possesses on CANDU-PHW with regard to cost.

- The detailed insight Ontario Hydro possesses on CANDU-PHW with regard to performance.

- Capital Cost information on LWR units built in the USA and extensive discussions with sister utilities in the USA.

- Detailed performance information on LWR units throughout the world.

- Interpolative judgment of the authors regarding expected LWR costs and performance of LWR in Ontario.

CANDU-PHW Costs -- Ontario Hydro

The actual cost data and projected cost data for CANDU-PHW units in Ontario have been presented above.

CANDU-PHW Operating Performance -- Ontario Hydro

The CANDU operating performance has been documented by the authors and published in a companion paper, Ontario Hydro CANDU OPERATING EXPERIENCE (NGD-9-1983).

The nine commercial CANDU units have demonstrated a Net Capacity Factor of 80% since first electricity production and 82% since the In Service Dates.

The authors use demonstrated capability for CANDU/LWR comparisons.

Capital Cost Information -- LWR -- USA

The actual or estimated initial Specific Dry Capital Costs for LWR units of 500 MWe and greater built in the USA are shown in Figure 4, based on information provided by a number of USA utilities, in USA dollars and converted to Canadian dollars at prevailing exchange rates.

The actual or estimated initial Specific Dry Capital Costs for CANDU-PHW units in Ontario Hydro are also shown in Figure 4 in Canadian dollars.

The following observations may be made:

- There is a wide scatter in the Specific Capital Cost data.
- The Pickering NGS-A and Bruce NGS-A CANDU-PHW stations have experienced a similar cost and cost trend compared to the average LWR.
- Future CANDU-PHW stations* are expected to have Capital Costs lower than or comparable to the lowest cost LWR's.

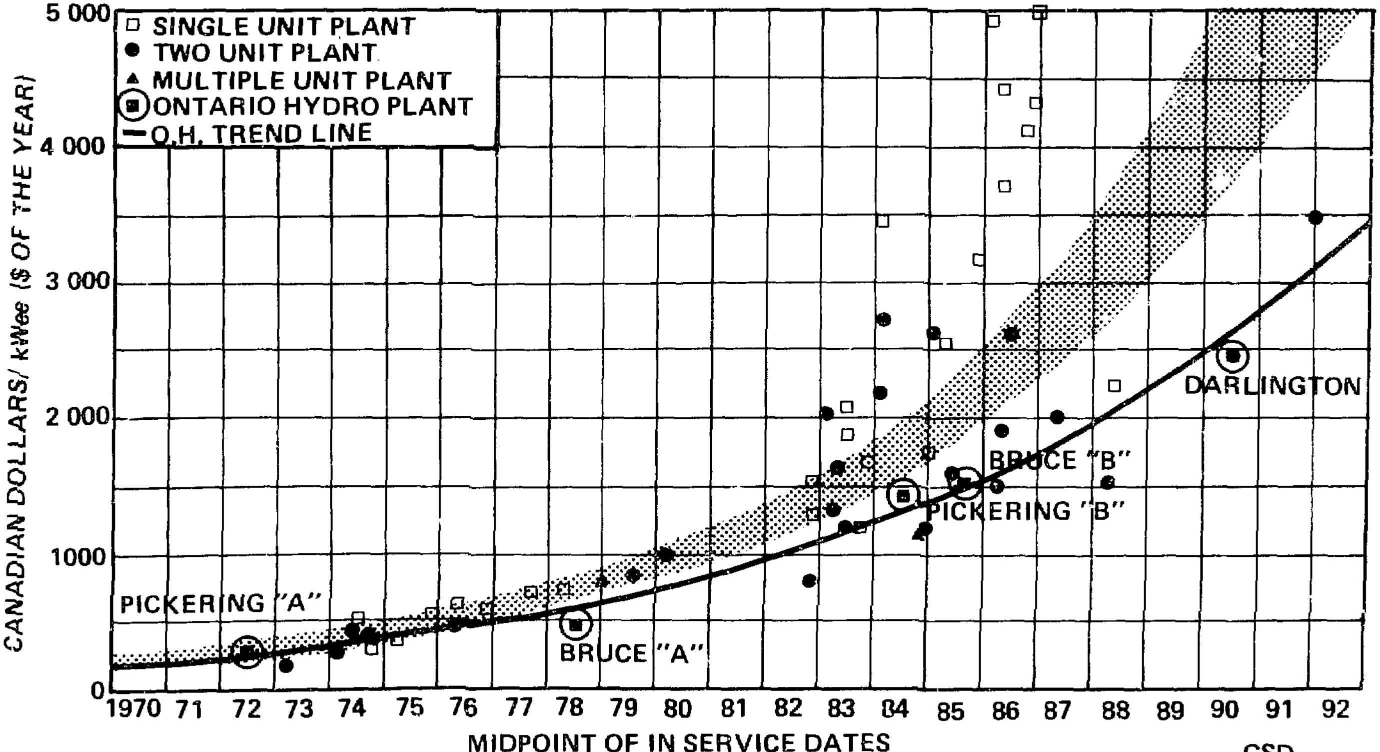
LWR Performance - Actual

The actual LWR lifetime performance has been reviewed and documented by Ontario Hydro and published in a document "World Nuclear Power Reactor Performance" (NGD-12 - 1983).

The lifetime average Capacity Factors of PWR and BWR have been 58% and 57%, respectively. In the following comparisons, the PWR performance of 58% has been used.

*Pickering NGS-B, Bruce NGS-B and Darlington NGS

FIGURE 4
INTER-UTILITY COMPARISON: NUCLEAR PLANTS
SPECIFIC DRY CAPITAL COST



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Authors' Judgment

Through examination, discussion and study of available data, the following judgments have been made by the authors:

Performance

There is a wide range of PWR performance (Capacity Factor) with a world average of 58%. The PWR Capacity Factor Performance is expected to further improve.

The available data is based upon stations which usually have only one or two units per station. Four unit stations (Ontario Hydro practice) are expected to have better performance due to improved diversity (spare parts, technical support, etc.)

The authors also feel that Ontario Hydro enjoys better than average project management and operator training.

The authors judge that if Ontario Hydro had an extensive PWR program (same number of units in service, same number of units per station and in service dates similar to the actual CANDU-PHW program), that the expected PWR performance capability in Ontario Hydro would be 70%.

This is to be compared with an average coal-fired capability of 69% in the USA and a demonstrated Ontario Hydro CANDU-PHW performance of 80% (net since first electricity production).

Both coal-fired and CANDU-PHW stations enjoy the advantages of on-power fueling.

The judged 10% Capacity Factor superiority of CANDU-PHW assumes a judged 6% Capacity Factor credit for on-power fueling and a 4% Capacity Factor credit for other concept advantages.

Ontario Hydro's lifetime performance capability of 72% for coal-fired stations is better than USA experience of 69% for 500 MWe units.

The authors judge that Ontario Hydro could achieve 80% Capacity Factors in coal-fired stations for base loaded operation if staffing levels and spare part diversity were increased. However, this is not economically justified for peak load application.

Capital Cost

The above comparison of Ontario Hydro and USA utility data (Figure 4) indicates no major Specific Dry Capital Cost difference to date between CANDU-PHW units built in Ontario and LWR units built in the USA.

Examination of the design requirements of the two concepts suggests there should be no major Dry Capital Cost differences for most facilities such as site, turbine-generator, cooling systems, instrumentation and controls, buildings and containment.

In the opinion of the authors, assuming identical supply capability and manufacturing volume, the CANDU reactor with on-power fueling should be less expensive due to the absence of enriched fuel, very demanding pressure vessel specifications as compared with pressure tubes, the need for in-core high pressure regulating and shutdown devices and the like.

However, in this paper, the cost comparisons which follow assume the Dry Capital Cost for CANDU-PHW and LWR in Ontario Hydro to be identical.

OM&A Cost

The Capacity Factor achieved by Ontario Hydro has depended, in part, on maintaining around-the-clock maintenance staff at four unit stations. This high staff level is economically warranted because of the high cost of burning coal whenever a CANDU unit is shut down. For example, in the Bruce NGS-A, a 1% Capacity Factor increment is equivalent to the wages of about 100 people

Since PWR units also have a low fueling cost compared with coal, around-the-clock maintenance would also be justified. In the opinion of the authors, there is no significant difference in optimum staff levels for four unit CANDU-PHW and four unit PWR in Ontario Hydro.

Similarly, the total OM&A Cost is expected to be the same.

Fuel

Examination of available USA data suggests that, for a large PWR program in Ontario, the Fueling Unit Energy Cost for PWR would be 7.67 m$/kW.he or higher in 1983.

This evaluation assumes the mining and refining costs of natural uranium are identical for CANDU and PWR. Enrichment cost is peculiar to the PWR units. Fabrication costs are particular to each design.

Decommissioning and Fuel Disposal

The 1982 Ontario Hydro cost experience and cost forecasts include provisions for the future costs of decommissioning and fuel disposal. In the opinion of the authors, these provisions for future costs have too much uncertainty to be meaningful in comparisons of alternative nuclear generation types. The comparison of CANDU-PHW in Ontario and PWR which follows is based on actual cost experience and excludes the provision for the future costs of decommissioning and fuel disposal. In the opinion of the authors, these exclusions do not have a significant effect on the relative costs of alternative types of nuclear generation for a major program.

Comparison -- CANDU-PHW Versus PWR -- Ontario Hydro

Table 4 is a cost comparison of CANDU-PHW and PWR in Ontario Hydro.

It is based on actual cost and performance experience of CANDU units in Ontario and the estimated performance and cost of PWR as outlined above.

Two sets of estimates are given for the PWR, corresponding to the world average Capacity Factor of 58% and the authors' judgment of 70% for a major PWR program in Ontario Hydro.

Table 4

ONTARIO HYDRO 1983 CANDU-PHW VERSUS PWR COSTS*

		PWR	
	CANDU-PHW**	High CF (Net)	Average CF (Net)
Station Size (MW e net)	2 060	2 060	2 060
Net Capacity Factor (CF Net %)	80	70	58
Interest and Depreciation UEC			
Dry Capital	5.27	6.02	7.27
Commissioning	0.21	0.24	0.29
Fuel	0.07	0.34	0.41
Heavy Water	1.39	-	-
Interest and Depreciation UEC	6.94	6.60	7.97
OM&A UEC	5.83	6.66	8.04
Fueling UEC	2.63	7.67	7.67
Heavy Water Upkeep UEC	0.74	-	-
Total UEC*	16.14	20.93	23.68

Note:

All UEC data in m$/kW.he 1983$.

*Does not include Provision for future Decommissioning or future Fuel Disposal Costs.

**Based on Pickering NGS-A costs.

This comparison indicates that:

- The TUEC for PWR operating in Ontario at the world average Capacity Factor (58%) would be approximately 47% higher than the TUEC of CANDU-PHW.
- The TUEC for PWR operating in Ontario at the authors' judgment of 70% Capacity Factor would be approximately 30% higher than the TUEC of CANDU-PHW.
- The costs of Capital Heavy Water plus Heavy Water Upkeep for CANDU are more than offset by the higher Fueling UEC of the enriched PWR fuel.

7.0 SUMMARY

1. Nuclear-Electric and Coal-Electric Generating Stations are the primary options in Ontario for new generating requirements for the period from 1984 to 2002.

2. Coal-Electric Generating Stations are the best choice to meet peaking requirements.

3. Nuclear-Electric Generating Stations are the best choice to meet base load requirements.

4. For base load applications, the CANDU-PHW has a proven lower cost than Coal-Electric. In 1983, the Total Unit Energy Cost for Pickering NGS-A was 18.44 m$/kW.he compared with the same size, same vintage Lambton TGS coal-fired station with a corresponding cost of 26.02 m$/kW.h.

5. CANDU-PHW has "inflation-proof" characteristics due to its very low Fueling Costs.

6. CANDU-PHW with on-power fueling is expected to continue to enjoy high Capacity Factor Performance.

7. The actual performance of the nine commercial CANDU-PHW units in Ontario is 80% Net Capacity Factor since first electricity production and 82% since the In Service Dates.

   The actual average lifetime performance of PWR in the world is 58% since first electricity production.

   The authors judge that 70% PWR Capacity Factor (net) would be achievable in Ontario for a mature PWR program.

8. For Ontario conditions and requirements, the estimated Total Unit Energy Cost of PWR units as compared to CANDU-PHW experienced costs indicates the PWR to be 30% higher, assuming a 70% PWR performance and a 80% CANDU performance.

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