RICHARD C. ZUKER
GLENN P. JENKINS

IN COLLABORATION WITH
HENRY LIM AND PIERRE POIRIER

Blue Gold

Hydro-Electric Rent in Canada

The findings of this study are the personal responsibility of the authors and, as such, have not been endorsed by the Members of the Economic Council of Canada.

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Introduction

The large increase in the world price of oil since 1973 has resulted in a corresponding rise in the value of Canada's oil and gas reserves. Since the cost of production from conventional reserves has not risen at a comparable rate, the result has been a significant increase in the economic rent from production of these resources.

In a similar fashion, the rise in the world price of oil has increased the value of resources that are substitutes for oil as sources of energy, such as coal deposits and hydro sites. Whereas the increased value of oil and gas reserves and the revenues from oil production are highly concentrated in western Canada, particularly in Alberta, the increased value of the hydro sites currently being utilized accrue primarily to Quebec, Ontario, Manitoba, and British Columbia.

Unlike the benefits arising from the low-cost hydro sites, which are generally passed on to consumers through lower electricity rates, the increase in oil prices has resulted in substantially higher revenues to the oil-producing provinces. These increased oil revenues to selected provinces in turn interacted with the existing (federally financed) federal-provincial Equalization Program. The structure of this program would have required the federal government to make large additional equalization payments to many of the other provinces. In response, the federal government introduced a series of measures designed to limit equalization payments arising from natural resource revenues in general, and oil and gas revenues in particular. These *ad hoc* changes to the equalization program led to a questioning of the principles that should underlie such a program.

As a part of its examination of federal-provincial fiscal relations,[1] the Economic Council of Canada commissioned a study to examine the fundamental principles that might form the foundation for an equalization program. This study[2] concluded that, on the grounds of national efficiency and equity, an equalization program designed to eliminate differences in the net fiscal benefits received by residents across provinces would be appropriate for Canada. Net fiscal benefits were defined as the value of public sector benefits received by a resident of a province less taxes paid.

To the extent that natural resource revenues collected by provincial governments are used to finance public services and/or to reduce provincial tax rates, such revenues should be taken into account in an equalization program. To achieve economic efficiency, the study concluded that it would be necessary to equalize all such per capita revenues among provinces.[3]

Because the benefits of lower electricity rates arising from low-cost hydro sites are not available to the residents of all provinces, this proposal would suggest that the fiscal benefits arising from hydro-electric consumption should be equalized in the same way as the benefits arising from the revenues on oil and gas and other natural resource productions. The problem is that, while most natural resource revenues collected by provincial governments are visible from the standard economic and financial accounts, such is not the case with economic rents from hydro-electric production. Even if provincial governments were to collect these rents by modifying the pricing policies of electric utilities, they would require some prior estimate of the magnitude of the economic rent that could be collected.

In this study, an attempt is made to develop estimates of the value of economic rent from the production of hydro-electricity. These estimates are made for the year 1979, which is the latest period for which a comprehensive set of data was available at the time this work was undertaken. The estimates are developed for the hydro-electricity generated (or used) by electric utilities in four provinces: Quebec (including Churchill Falls), Ontario, Manitoba, and British Columbia. These electric systems accounted for 93 per cent of the hydro-electricity generated by utilities in Canada during 1979. Using the estimates developed for these four provinces, approximate values are derived for the rent arising from the hydro-electricity generated by utilities in the other provinces. It should be noted that industrial establishments generated over 11 per cent of the hydro-electricity in Canada in 1979. No estimate of the economic rent from this production is developed in this study.

We find that economic rent attributable to hydro-electric generating sites in Quebec, Manitoba, and British Columbia during 1979 amounted to approximately $4 billion. Of that amount, approximately

47 per cent was derived from the hydro sites used by Quebec. In turn, slightly more than 30 per cent of the economic rent accruing to Quebec was derived from the Churchill Falls hydro site. Hydro sites in Ontario resulted in approximately 19 per cent of the hydro rent in these four provinces, whereas Manitoba and British Columbia accounted for 13 per cent and 21 per cent, respectively.

Given the magnitudes of these estimates, any comparison of the relative economic well-being across provinces that fails to account for the value of this resource is likely to yield misleading results.

1 The Concept of Hydro-Electric Rent

The relative importance of hydro-electricity in the total production and consumption of all forms of electricity generated in Canada in 1979 is summarized in Tables 1-1 and 1-2. In that year, hydro accounted for more than 94 per cent of the electricity generated by utilities in four provinces – Quebec, Manitoba, British Columbia, and Newfoundland – and over two-thirds of the electricity generated in the nation. Prince Edward Island was the only province without any hydro-electric generating plants.

An examination of the proportional distribution by province reveals that Quebec accounted for more than one-third of the hydro-electricity generated in Canada, Newfoundland close to 20 per cent, Ontario about 19 per cent, British Columbia about 14 per cent, and Manitoba just under 10 per cent. The energy sold from Churchill Falls to Quebec accounted for more than 16 per cent of total hydro-electricity generated in Canada.

The consumption of electric power from all sources relative to net provincial production provides a measure of the shortfall or surplus of electrical energy requirements in each of the provinces. At one

Table 1-1

Hydro Power

Hydro-electricity as a share of the total electricity generated by electrical utilities and industrial establishments, relative importance, and proportion of consumption to production, by province, 1979

	Electrical utilities			Industrial establishments	
	Hydro generation as a share of total provincial hydro generation	Relative importance of hydro generation	Electrical consumption in relation to net production (sales within province)*	Hydro generation as a share of total provincial hydro generation	Relative importance of hydro generation
			(Per cent)		
Newfoundland	96.9	19.3	15.5	1.3	2.0
	(82.7)†	(3.0)†	(99.7)	(8.0)†	
Prince Edward Island	–	–	491.8	–	–
Nova Scotia	19.9	0.5	106.4	3.4	0.1
New Brunswick	36.4	1.4	90.9	2.1	0.2
Quebec	94.7	34.6	128.7	15.7	50.0
	(96.3)†	(51.0)†	(83.7)	(11.2)†	
Ontario‡	38.6	18.8	95.4	4.5	6.9
Manitoba	99.5	9.5	61.9	–	–
Saskatchewan	26.8	1.1	113.4	3.5	0.3
Alberta	7.0	0.7	98.4	–	–
British Columbia	98.2	13.8	96.6	27.4	40.4
Yukon and Northwest Territories	74.3	0.3	100.0	3.7	0.0
Canada	67.9	100.0	90.3	11.4	100.0

*Computed as:

$$\frac{[\text{sales to ultimate customers}] + [\text{sales to industrial establishments}] - [\text{purchases from industrial establishments}]}{[\text{total generation}] - [\text{used in own plant}] - [\text{losses and amounts not accounted for}]}$$

†Reflects reallocation from Newfoundland to Quebec of 35,220,700 megawatt-hours of hydro-electricity exported from Churchill Falls.

‡Energy used in own plant is reduced by the amount used by Ontario Hydro to produce heavy water and in construction projects, which increases both consumption and net production in Ontario (and correspondingly for Canada) by 701,925 megawatt-hours; see Ontario Hydro, *Statistical Yearbook* (Toronto: 1979), p. 41.

SOURCE Statistics Canada, *Electric Power Statistics. Volume 2. Annual Statistics*, Statistics Canada cat. no. 57-202, 1979, Tables 2 and 3.

extreme, Prince Edward Island in 1979 consumed almost five times as much electricity as was produced on a net basis in that province.[1] By contrast, Newfoundland exported about 85 per cent of the electricity that it produced, whereas, for Manitoba, net exports were almost 40 per cent of net production. Net exports of electricity were less than 10 per cent of net production in Nova Scotia, New Brunswick, Ontario, Alberta, and British Columbia. In the case of Quebec, consumption exceeded production by 29 per cent but, if Churchill Falls were allocated to Quebec, then consumption would have accounted for only 83 per cent of production. Net exports to the United States represented 10 per cent of the net production of electricity in the nation.

Industrial establishments accounted for more than 11 per cent of hydro-electricity generated in Canada in 1979. The relative importance of hydro-electricity generated by industrial establishments, rather than provincial utilities, was greatest in British Columbia and Quebec, where more than 25 per cent and 15 per cent, respectively, of total hydro power was produced by industry. A look at the proportional distribution by province shows that Quebec and British Columbia accounted for 50 per cent and 40 per cent, respectively, of the hydro power generated by industrial establishments in Canada in 1979.

Table 1-2 shows the distribution of energy produced and consumed nationally by various sources of power, based on the equivalent amounts of heat produced by each. In order to measure nuclear and hydro-electric power on a comparable basis with fossil fuels, the former are generally upgraded by a factor of close to three since, in the process of converting fossil fuels to electricity in thermal generating stations, about two-thirds of their heat value is lost. Hence, an adjustment is necessary to give the heat equivalent in kilowatt-hours produced by hydro and nuclear power in generating electricity on a basis comparable with that produced by fossil fuels for the same purpose. The heat values for hydro and nuclear electricity shown in Table 1-2 incorporate this upgrading approach. On that basis, hydro-electricity represented about 25 per cent of the production and consumption of energy in Canada in 1979.

Table 1-2

Importance of Hydro Electricity, Canada

Production and consumption of energy, by source, 1979

	Primary production		
	Gross*	Net†	Consumption‡
	(Per cent)		
Coal and steam	8.0	2.4	3.6
Crude oil	34.5	33.2	38.9
Natural gas	29.6	28.6	19.6
Electricity	27.8	35.7	37.9
Thermal	–	7.9	9.2
Nuclear	3.3	3.3	3.5
Hydro	24.5	24.5	25.2
	(Terajoules)		
Total energy	10,424,083	10,424,083	8,215,686

*Recorded as primary production by Statistics Canada, except that nuclear and hydro-electricity are valued at 10.5 terajoules per gigawatt-hour, instead of 3.6, to reflect the fossil fuel equivalent.

†Calculated by reducing the production of coal, crude oil, and natural gas for energy used, in primary and/or secondary form, to produce thermal electricity. A total of 828,013 terajoules of energy of these fuels (together with minor quantities of some other fuels) were used to produce thermal electricity. The kilowatt-hours of electricity produced had a heat value of 276,257 terajoules (when valued at 3.6 terajoules per gigawatt-hour), representing a loss of about two-thirds in conversion to electricity.

‡Includes primary and secondary forms, with nuclear and hydro-electricity valued on a comparable basis with fossil fuels. The difference between net primary production and consumption of energy is accounted for by exports, imports, producer consumption, nonenergy use, stock variations, and a number of other minor adjustments.

SOURCE Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada*, Statistics Canada cat. no. 57-003, 1979-IV, Table 1-B, and Statistics Canada, *Electric Power Statistics. Volume 2. Annual Statistics*, Statistics Canada cat. no. 57-202, 1979, Tables 2 and 11.

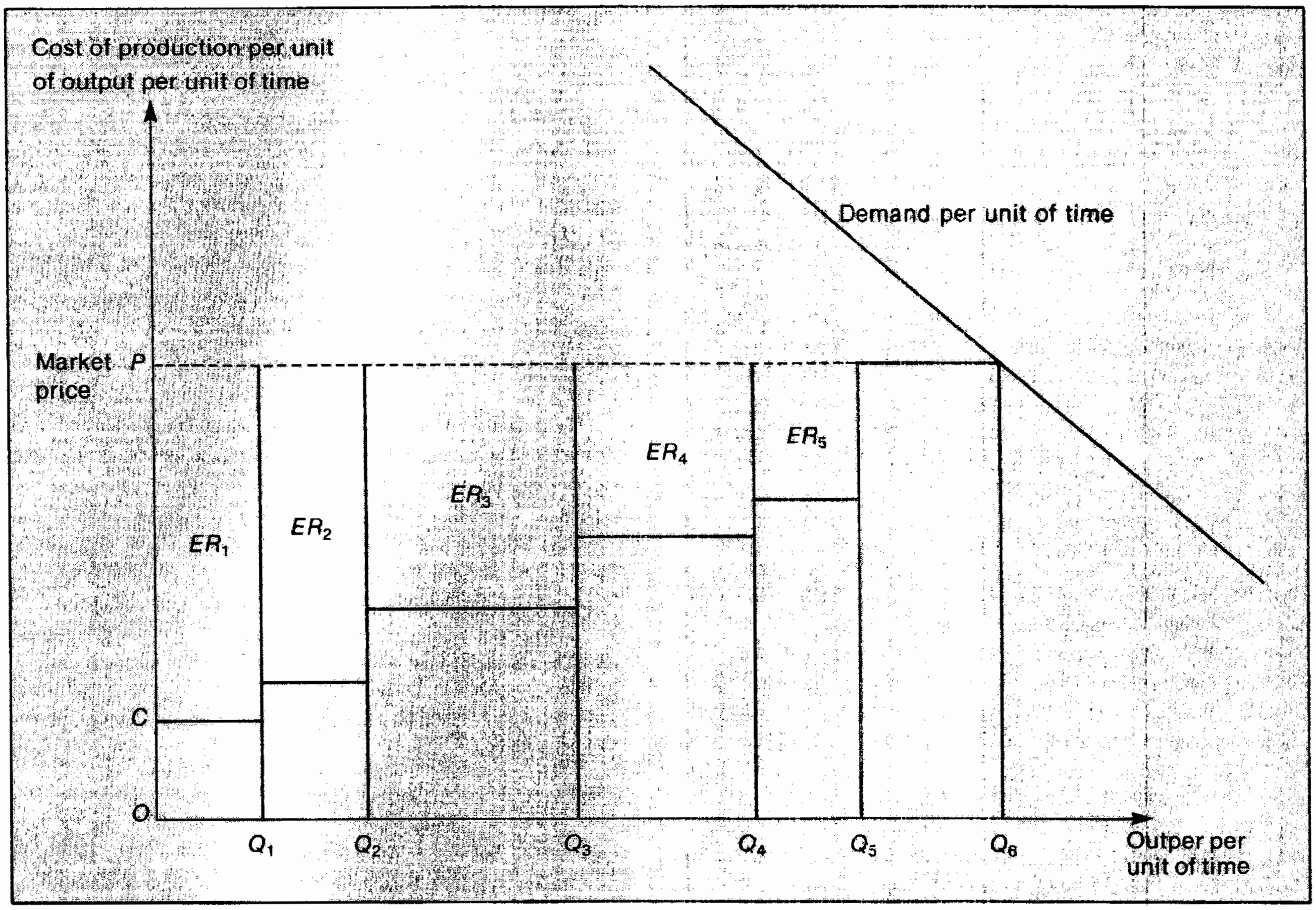
Economic Rent

Economic rent arising from the production or exploitation of a natural resource is said to exist when the perfectly competitive market price for the resource (or for the goods or services provided from the use of that resource) exceeds the most efficient (least cost) method of production. The cost of production includes both the cost of labour and an appropriate return to the capital employed.[2] The minimum cost of production depends on the specific characteristics of the resource in question, such as its relative quality, the relative difficulty of exploitation, and the production technology available.[3] Economic rent on natural resources exists because, at a given location and with a given technology, the supply of a resource is fixed. It thus tends to vary among different locations, and tends to change over time as production technology changes.[4] With the cost of production held constant, a market price in excess of production costs results in economic profits, because it provides returns to capital and/or labour above and beyond their opportunity costs.[5]

Figure 1-1 presents a simple representation of economic rent when the resource is produced at a number of different locations, each with a different production cost and fixed capacity. Some relevant examples are different pools of crude oil, different grades of deposits of some other mineral, or different

Figure 1-1

Economic Rent



hydro sites. In the figure, the sources of production are ordered from lowest to highest cost per unit.

If, in such a market, the cost per unit for the most costly (marginal) source of production is equal to the market price, then no economic rent is derived. For all inframarginal sources of supply for which the cost per unit is less than the market price, there is an economic rent on each unit of output. This rent is equal to the difference between the market price and the unit cost of production. As shown in Figure 1-1, the total economic rent obtainable on production from a given source of supply is represented by the rectangle bounded below by the cost of production *C* and above by the market price *P*.

The steplike line representing the marginal cost of production per unit is the industry supply curve. Thus, the market price, or the reference price for the measurement of economic rent, is simply the marginal cost at the level of output at which supply and demand are in equilibrium.

Measurement of Hydro Rent

From the previous analysis, it can be seen conceptually that two variables are required for estimating hydro rent: the marginal cost of hydro-electric supply, which provides a reference price, and the cost of hydro production.

There are essentially two polar approaches to the measurement of the marginal opportunity cost of electric production from hydro sources. They differ in the way electrical service is viewed.

At one extreme, electricity can be viewed broadly as energy. For example, one could estimate the cost of providing users with some quantity of energy, measured in British thermal units or joules, whether directly from refined petroleum products or natural gas, or from hydro-electricity. The weakness of this approach is that it does not recognize different purposes for electric use, such as space heating, lighting, and motive power, each with a different least cost, alternative energy source. For example, in the case of space heating, the least cost alternative would likely be gas or oil furnaces. To replace electricity used for lighting and electric motors, the energy produced from other sources would also have to be in the form of electricity. In these cases, the full opportunity cost of the hydro-generated electric energy must include not only the fuel cost but also the capital cost associated with providing alternative sources of energy.

Another approach is to find the least cost alternative for replacing the electricity produced at the hydro sites. This approach has two merits over the first one considered. It would measure the lowest cost of producing an identical service, that is, a perfect substitute. And it would most likely yield the minimum cost for replacing hydro-electricity, because it would take into account the economies of scale arising from the centralized generation and delivery of electricity.

If the best way to proceed is to determine the cost of replacing the hydro-electricity at least cost, there are again two possibilities. One approach is to estimate the minimum cost of building new thermal plants to replace only the current hydro-electric facilities, while holding the remainder of the electric generating and delivery system constant.[6] The difference between the cost of these thermal plants and the economic cost of the present hydro facilities would then provide an estimate of the cost saving – that is, the economic rent arising from hydro production. The second method is to estimate the minimum cost of establishing a completely new alternative production system for all electricity. In this case, the difference between the cost of the least cost, all-thermal alternative and the current system would be used to estimate the economic rent from hydro production. The interdependencies in a mixed hydro-thermal system are such that a completely new all-thermal system would be less than one with the current thermal facilities unchanged, even under ideal conditions. Inefficiencies in the current system arising from inaccuracies in the forecasts of prices, quantities demanded, and production costs would reinforce this conclusion.

Demand and Supply

An important feature of the demand for electricity is that it fluctuates greatly with time. Because it is expensive to store electricity in most cases, it must be produced at the time it is required.

Figure 1-2 illustrates the hourly electricity demand facing a typical electric utility over a one-day period. The demand or load is usually recorded in kilowatts or megawatts; and the area under the curve is a close approximation of the total energy demanded that day. Demand is usually lowest during the night hours.

Similarly, one could draw a graph of the hourly demands facing a utility for every hour of the year, ordered chronologically. Such a load curve is illustrated in simplified form in Figure 1-3. In Canada, demand is generally much higher in the winter months when demand for electric heating is high. The peak demand or peak hourly load for the year usually occurs on a very cold winter day.

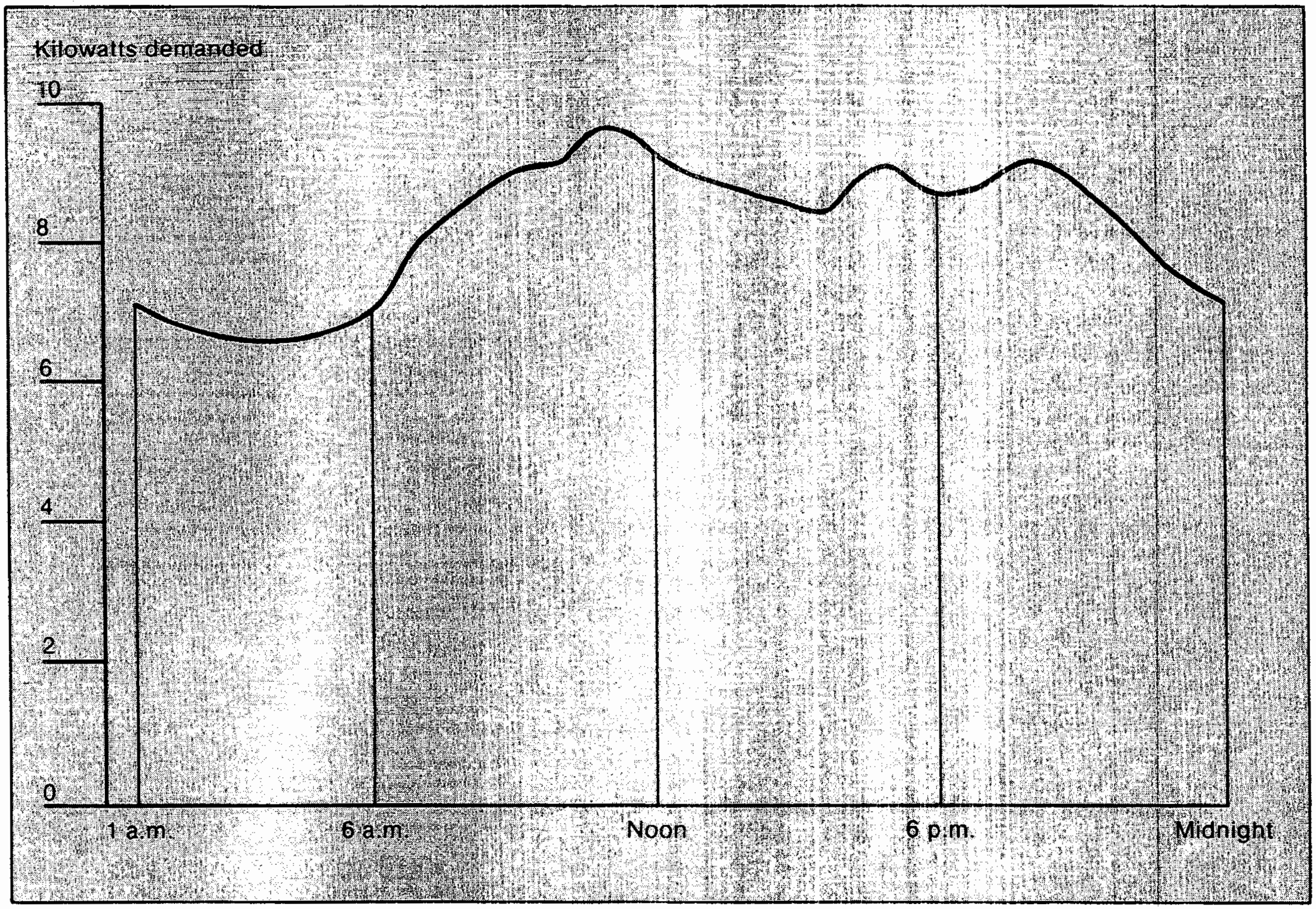
The peak demand in a year is a most important variable for planning purposes because it is the maximum amount of electrical energy that must be supplied by the utility at any point in time within the year. If imports cannot be relied upon, then the utility must have sufficient generating capacity to meet this peak demand. Moreover, because of the long period of time required to plan for and construct large generating stations and the long useful life of these facilities, utilities must plan their generating system based on a forecast of peak demands for many years into the future.

In addition, the utility must maintain reserve capacity in excess of its projected peak demands. This allows for such factors as forecasting errors, equipment breakdowns (forced outages), or low-water conditions at hydro sites. The reserve capacity considered prudent by electric utilities in Canada varies from about 12 to 25 per cent of peak demand, with the percentage depending on the mix of types of generating equipment in place. Utilities also often attempt to reduce peak demands by selling interruptible power to industry. This allows the utility, at its discretion, to cut back on electricity sold to these firms at critical times, so that it can reduce the total demand on the system.

One could take the hourly loads for a given year and reorder them from highest to lowest. The relationship obtained measures the number of hours in the year for which hourly demand is greater than or equal to various demand levels. A graph of these levels of demand against the number of hours is referred to as an "annual load duration curve." A typical curve of this type for an electric utility is shown in Figure 1-4.

Figure 1-2

A Typical Daily Load Curve for an Electric Utility



In Figure 1-4, the highest demand attained in any hour of the year is D_1 kilowatts and the lowest is D_4 kilowatts. For H_2 hours of the 8,760 hours in a year, demand is greater than or equal to D_2 kilowatts or, alternatively (starting with the highest demand), D_2 kilowatts is the minimum hourly demand for H_2 hours. Similarly, for H_3 hours of the year, demand is greater than or equal to D_3 kilowatts and, correspondingly, demand is less than D_3 kilowatts for $8,760 - H_3$ hours in the year. It is important to note that the area under the load duration curve is a close approximation of the quantity of energy demanded in a year.

The annual load factor is defined as the ratio of the average of hourly demands for the year to the peak hourly demand in the year. Equivalently, the load factor is the ratio of the area (energy) under the annual load duration curve to the area of the rectangle bounded above by the peak demand in kilowatts and to the right by the total number of hours in the year – the total energy that would be demanded if the peak demand occurred throughout the year. A daily load factor or a monthly load factor can be defined similarly. The annual load factor is therefore a measure of the regularity or flatness of the annual load duration curve. For example, at one extreme, the maximum possible annual load factor of unity would indicate equal hourly demands throughout the year and a horizontal annual load duration curve. A low value for the load factor would indicate that the annual load duration curve falls steeply to the right.

Typically the annual load factor for a large electric utility in Canada is in the order of 0.55 to 0.70. With some important exceptions, utilities generally prefer to have higher rather than lower load factors because this allows them to reduce generating costs per unit of output. A flatter load curve would, however, require behavioural and/or technological changes by users willing to change their consumption patterns.[7]

Figure 1-3

A Typical Annual Load Curve for an Electric Utility

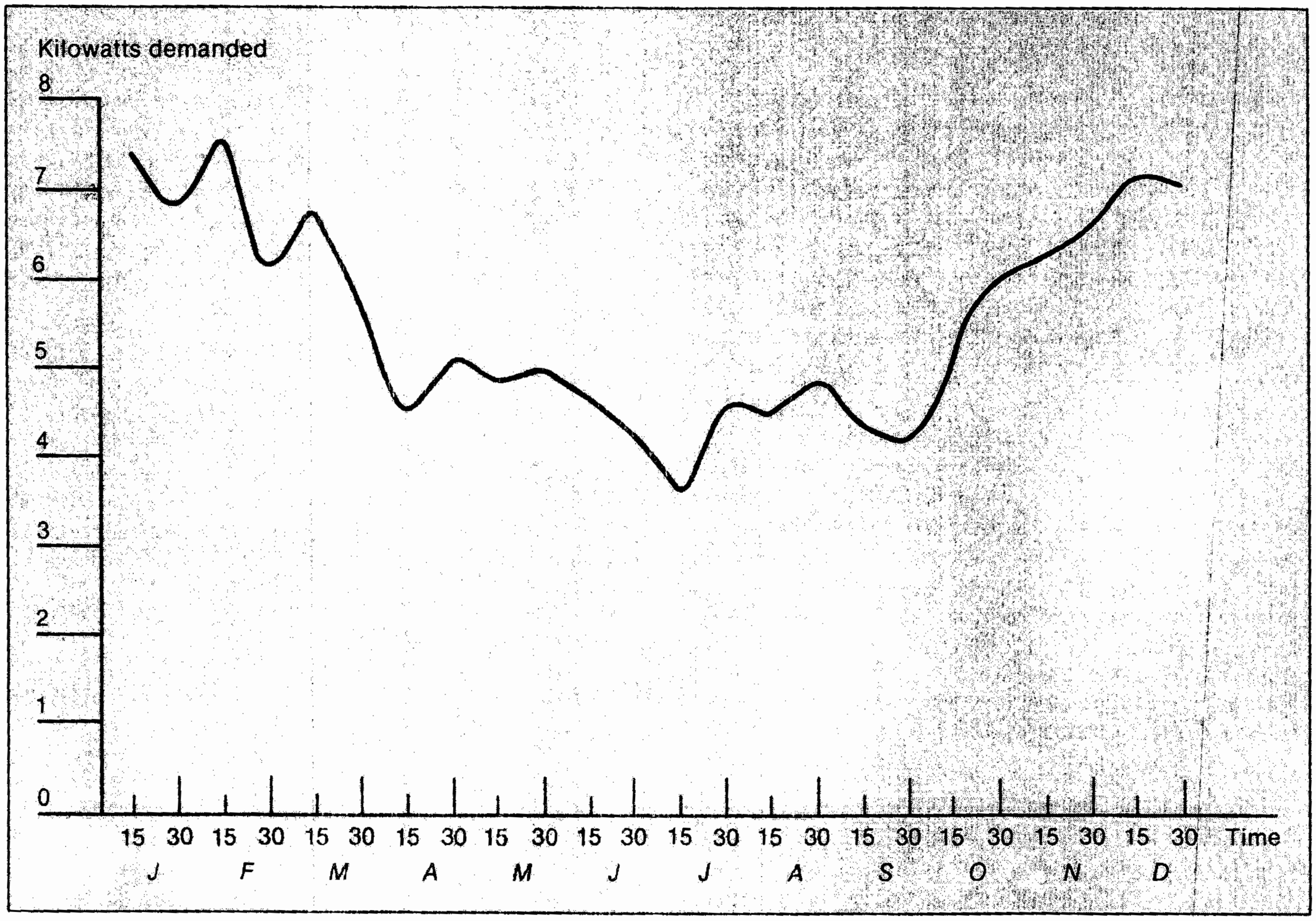
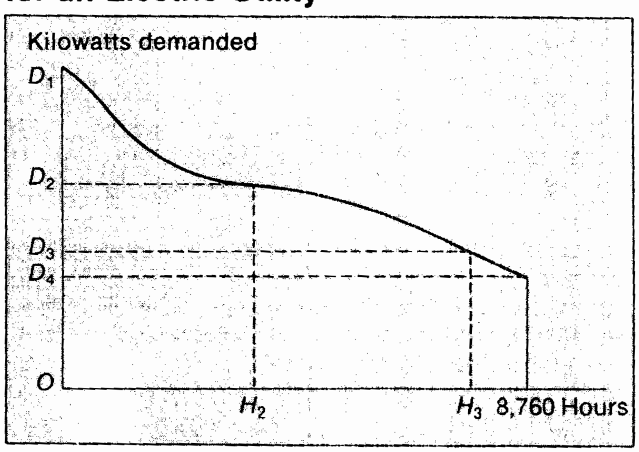


Figure 1-4

A Typical Annual Load Duration Curve for an Electric Utility



This would impose costs on users. Changing the shape of the load curve in order to minimize costs for society as a whole is an important issue, and is heavily dependent upon the pricing and marketing policies of the electric utility.

It is evident from Figures 1-2, 1-3, and 1-4 that the variability in hourly demand on a daily or seasonal basis creates formidable problems for electric utilities as they attempt to minimize production costs while meeting these demands. In order to have sufficient capacity to meet peak demand, the utilities must maintain generating facilities utilized less than full time. Certain generating facilities may be utilized for only a very small number of hours in a year.[8]

How do utilities attempt to minimize production costs in these circumstances? They do so by drawing upon a variety of different electric generating technologies. One important distinguishing characteristic of these technologies lies in their relative differences in the fixed and variable costs of producing a kilowatt of electricity. A second important distinguishing characteristic of these technologies is the feasibility and cost of changing output levels by significant amounts in a short period of time, referred to as the startup and shutdown costs.

At one extreme is a hydro dam in which the falling water is used to operate turbines. These facilities usually involve high fixed costs per kilowatt of capacity, but once installed, the variable cost per hour of operation (or per kilowatt-hour of electricity produced) is very low or negligible.

Nuclear generating stations with their high fixed capital costs per kilowatt and relatively low operating costs are also in this category. Since it is difficult and costly to change the level of output significantly in a short period of time, nuclear plants are operated most efficiently on a continuing basis as close to full power as possible.

Next along the spectrum are coal-fired plants with lower fixed costs per kilowatt of capacity than nuclear plants, but with higher variable costs per kilowatt-hour of energy produced. The higher variable costs are due to higher fuel costs. It is less costly, however, to vary the output level over a short period of time in coal-fired plants than in nuclear plants. Oil-fired plants in turn tend to have lower fixed costs but higher operating costs than coal-fired plants.

Next in line are gas turbines with relatively low fixed costs per kilowatt of capacity but high variable costs, due to high fuel costs, per unit increase in the hours of operation. These facilities, however, can be started up quite quickly at low cost.

To meet the peak demands during a day or season, an electric generating system may also utilize "peaking" hydro stations. These may be reservoirs near large dams, seasonal hydro sites, or pumped storage installations. These facilities can be brought into production very quickly, and can be operated at low variable cost for as long as the water in the reservoir allows.

2 Cost Minimization, Opportunity Costs, and the Measurement of Hydro Rent

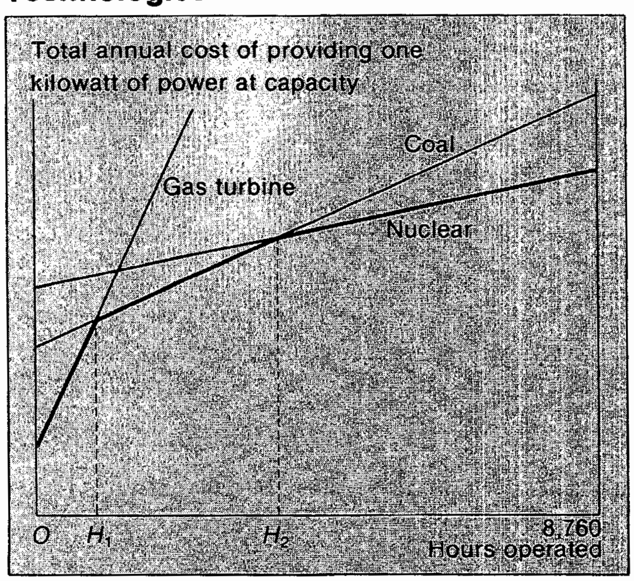
As discussed in the first chapter, we view hydroelectric rent as the cost saving in the production of electricity made possible by the availability of hydroelectric resources. For the most part, conventional thermal and nuclear technologies constitute the least cost alternatives to hydro generation. We now turn to outline conceptually the general approach to minimizing cost for all-thermal and mixed hydro-thermal generating systems.

An All-Thermal System

The nature of the fixed and variable costs for the nuclear, coal, and gas turbine thermal generating technologies are illustrated in Figure 2-1. In this figure, one line corresponding to each technology shows the total annual cost of providing one kilowatt of power using that technology when operated for a given number of hours in a year. The slope of each line is the marginal cost of producing one kilowatt of power for one additional hour of the year. From this diagram, we can trace which type of generation would provide electricity at least cost, depending on the number of hours for which a given level of power is demanded.

Figure 2-1

Cost Comparison of Thermal Generating Technologies



For example, if power is to be provided for more than H_2 hours in a year, then it can be provided at least cost using nuclear generation. For power required for fewer than H_2 hours in a year, but more than H_1 hours, a coal-fired plant would be most economical. For power required for fewer than H_1 hours, a gas turbine would provide it at least cost.

By linking this to a diagram of the annual load duration curve, we can show how a utility would draw upon these various types of generating facilities to satisfy the variable hourly demands within a given year in a way that would minimize cost. This is illustrated in Figure 2-2, where the annual load duration curve is set directly above the cost curve diagram.

As noted, nuclear generation would minimize the cost of power that is required for more than H_2 hours of the year. From the annual load duration curve, we can see that, at most, D_2 kilowatts of power is needed for H_2 hours of the year or longer. Thus, for cost minimization, D_2 kilowatts of nuclear capacity is required.

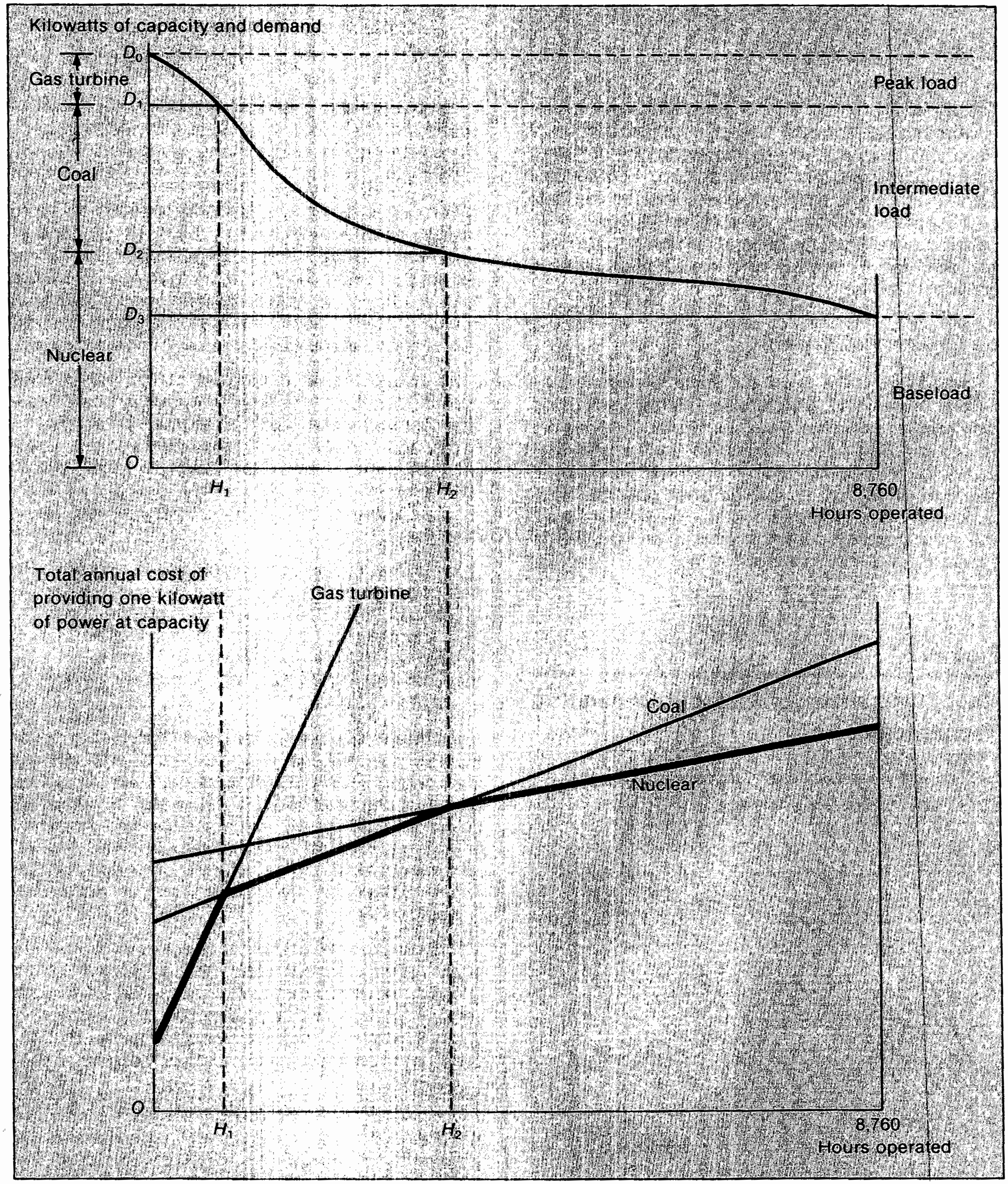
For power demanded for more than H_1 but fewer than H_2 hours of the year, coal-fired generation is least costly. From the load duration curve, it can be seen that, at most, $D_1 - D_2$ kilowatts of additional power are demanded during this period; therefore, $D_1 - D_2$ kilowatts of coal-fired capacity are required to minimize cost. Lastly, $D_0 - D_1$ kilowatts of gas turbine capacity are needed for cost minimization for H_1 hours of the year.

From the annual load duration curve in Figure 2-2, it can also be determined that D_3 kilowatts (the minimum hourly demand within the year) of nuclear capacity are required to be operated on a year-round basis. The full amount of nuclear capacity, D_2 kilowatts, is required for only H_2 hours of the year.

In the case of coal, no capacity is needed for 8,760 – H_2 hours of the year; that is, coal plants are idle for that many hours. Coal-fired generation is required at full capacity, $D_1 - D_2$ kilowatts, for as few as H_1 hours of the year. Finally, gas turbines are idle

Figure 2-2

Minimizing Generating Costs in an All-Thermal System



for as many as 8,760 – H_1 hours of the year, and the full capacity of $D_0 - D_1$ kilowatts is used for only the peak hours of the year.

Recall that the area under the annual load duration curve is equal to the total amount of energy demanded within the year. The annual load duration curve in Figure 2-2 thus indicates how much energy is to be provided by each type of generation for cost minimization. The energy to be supplied by each type of generation is given by the area under the annual load duration curve indicating the extent to which each technology is to be utilized. For example, the area under the annual load duration curve bounded above by a horizontal line through D_2 is the quantity of nuclear energy to be generated. Similarly, the area under the annual load duration curve between horizontal lines through D_1 and D_2 is the total annual energy to be generated by coal. The area under the curve above a horizontal line through D_1 measures the energy to be produced by gas turbines if generating costs are to be minimized.

The amount of energy produced by a given technology can then be used to determine the annual rate of capacity utilization for that type. The capacity utilization rate can be measured as the ratio of the energy supplied to the energy that could be supplied if the generating plants were fully utilized on a year-round basis (ignoring maintenance). The denominator, the energy supply possible at full capacity, is simply the product of the capacity of that type of power generation and 8,760 hours in a year.

By drawing horizontal lines at levels D_1 and D_2 across a diagram of hourly loads in a day, such as the one shown in Figure 1-2, one can see for how long the three types of plants should be operated at different levels of utilization to meet the hourly demands throughout the day.

The terms baseload, intermediate load, and peak load are often used to characterize (vertical) segments of the annual load duration curve. As shown in Figure 2-2, the baseload would be the amount of demand, D_3 kilowatts, that must be met on a year-round basis. Peak load refers to demands that occur for a small number of hours, and intermediate loads – as the term implies – for demands between these extremes. In an all-thermal system, nuclear or coal-fired stations are generally utilized to meet baseload demand, while coal or oil are used to meet intermediate loads, and gas turbines are brought into service to fulfil peak load demands.

The total generating cost in a year can be determined from the diagrams in Figure 2-2. Referring to the cost curve diagram, it can be seen that, for each technology, the generating cost can be split into annual fixed cost and variable cost components. The annual fixed cost per kilowatt is shown by the value of the intercept of a technology line on the vertical axis, and the variable cost is the difference between the total cost and the fixed cost.

The total annual fixed cost for each plant type is thus the fixed cost per kilowatt times the number of kilowatts of capacity required. To compute the total variable cost, one must first know the number of kilowatt-hours of energy generated in the year.

For each type of generating plant, there are fuel and other operating costs that vary directly with the amount of energy produced by the plant. These marginal running costs per kilowatt-hour vary depending on the type of fuel and the vintage of the plant.

For a given plant type, i, the total annual variable cost of generation can be computed as follows:

$$TVC_i = \int_{D_L}^{D_H} D(l)\, MRC_l^i dl\,,$$

where

$H = D(l) =$ the duration in hours of demand or load l, from the annual load duration curve, such that $D(l_1) \geqslant D(l_2)$ for $l_1 \leqslant l_2$;

$MRC_l^i =$ the marginal running cost for an additional unit of capacity of plant type i operating at load level l (in Figure 2-2, MRC_l^i is assumed constant for all of l by virtue of the constant slope of the total cost curve);

$D_L =$ desired capacity of the generating technologies to be operated for more hours in the year than type i; and

$D_H =$ D_L plus the desired capacity of type i.

The total cost for each plant type is then the sum of the total fixed and variable cost components.

A Mixed Hydro-Thermal System

The considerations for cost minimization for hydro generation are somewhat different from that for thermal generation, because hydro may often be subject to energy limitations. In contrast, in considering thermal generation above, we have assumed, ignoring maintenance requirements and forced outages, that the plants could be operated at full capacity throughout the year, if this were required for cost minimization. In contrast, some hydro generating sites may not be operable at full capacity throughout the year, because the water flow may be insufficient. Therefore, the supply of energy available from a hydro site may be less than that available at full capacity. Given the estimated energy available from a hydro site, minimizing generating costs for the total system usually implies the use of all the hydro energy available, because the marginal cost of hydro energy is generally less than that for thermal. It can be shown that the optimal way to incorporate hydro generation in a mixed hydro-thermal system is to locate the hydro capacity under the load duration curve such that the total area under the curve between these demand levels is exactly equal to the hydro energy available from a given site – that is, so that the total hydro energy available is utilized.[1]

Suppose there are two hydro sites available, a baseload site, which can be operated at full capacity throughout the year, and a peaking site, which can only be operated at variable capacity levels throughout the year. In the latter case, there may, for example, be a reservoir that could store a sufficient amount of water to allow operation for several hours in a day at full capacity.

The integration of these hydro facilities with the thermal technologies considered in the previous section is illustrated in Figure 2-3. The capacity of the baseload site is assumed to be D_C kilowatts. Full use of all the energy available implies that the site should be operated at that capacity level on a year-round basis.

In the case of the limited energy site, a capacity of $D_A - D_B$ kilowatts is assumed. The points D_A and D_B are located under the annual load duration curve, so that the area under the curve between horizontal lines through D_A and D_B is equal to the annual hydro energy available.[2]

The effect of the availability of these hydro sites on the allocation of production among the various thermal generating technologies is illustrated in Figure 2-3. With a capacity of D_C kilowatts of baseload hydro, the nuclear capacity required for cost minimization would be reduced to $D_2 - D_C$ kilowatts from D_2 kilowatts. Nuclear energy production would correspondingly be reduced by the rectangle bounded above by a horizontal line through D_C.

As a result of the availability of the run-of-the-river hydro site, there would be a decrease in the capacity and energy required of both coal and gas turbines. In the case of coal, $D_1 - D_B$ kilowatts of capacity would be displaced by hydro, so that the capacity required would be reduced to $D_B - D_2$ kilowatts from $D_1 - D_2$. Similarly, gas turbine capacity requirements would decrease to $D_0 - D_A$ kilowatts from $D_0 - D_1$ kilowatts in the mixed hydro-thermal system.[3]

By projecting from these capacity cut-off points on the load duration curve downward onto the horizontal time axis, we can see how the plants would be operated in the mixed system for cost minimization. The baseload hydro site would be operated at full capacity, D_C kilowatts, on a year-round basis. In the case of nuclear power, $D_3 - D_C$ kilowatts of capacity would be operated year-round, and the total capacity now required, $D_2 - D_C$ kilowatts, would be operated for H_2 hours of the year. In this example, both the capacity required and the utilization rate for nuclear plants would decline with the availability of baseload hydro.

The run-of-the river hydro site would be operated for as many as H_B hours of the year and at full capacity, $D_A - D_B$ kilowatts, for only H_A hours of the year.

The total coal capacity required, $D_B - D_2$ kilowatts, in the mixed system would be operated for H_B hours of the year. This is greater than H_1 hours for which coal capacity would be utilized in the all-thermal system. Thus, as this example illustrates, the availability of peaking hydro would generally result in a decrease in coal capacity but an increase in the utilization rate of coal plants. Coal plants would be used to generate electricity for up to H_2 hours a year, as in the all-thermal case.

In the mixed system, gas turbine capacity would be required for H_A hours of the year at most, which is less than H_1 hours of the year in the all-thermal system. As a result, both the capacity and the utilization rate of gas turbines would decline in the example shown.

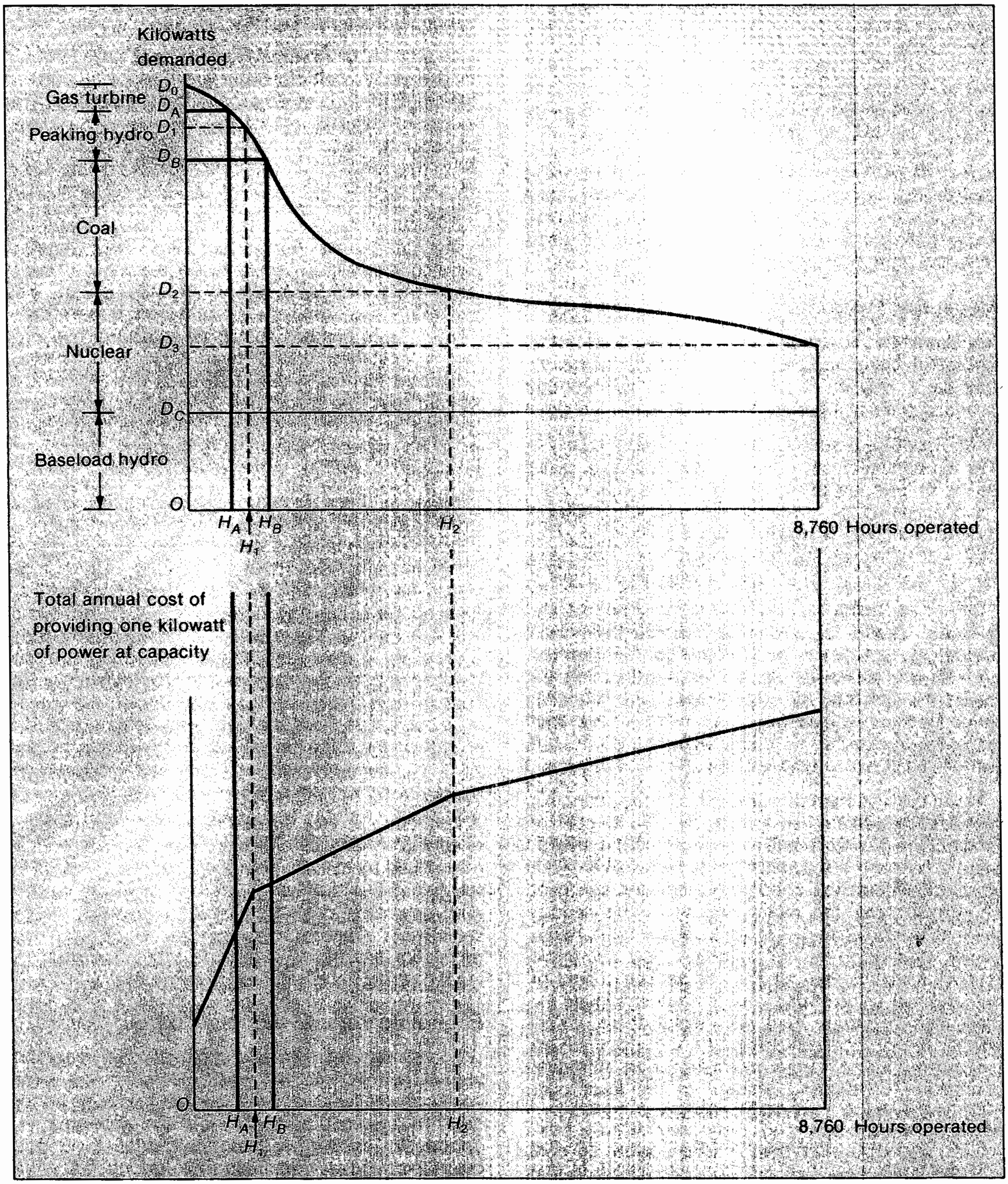
It must be emphasized that the cost minimization analysis presented above is a gross oversimplification of the procedures that utilities follow to minimize cost in an actual system. The cost minimization problem faced by utilities is far more complex, because many additional considerations must be taken into account.

A list of some of these complicating factors would include:

- startup costs,
- adjustments to capacity and fuel consumption of the various types of generation to meet reliability criteria, given forecasting errors and the probabilistic nature of forced outages,
- maintenance scheduling costs,
- economies of scale in generating facilities, particularly thermal units and stations, and the trade-off between economies of scale and reliability,
- the uncertain levels of water flow,
- the optimal use of reservoirs,
- transmission costs and transmission line losses, and
- fuel inventory costs.

Figure 2-3

Minimizing Generating Costs in a Mixed Hydro-Thermal System



Moreover, we have considered, in the above analysis, only cost minimization for a given year, not the long term. Because of the general increase in demand over time – that is, the annual load duration curve is moving upward – and the long planning and construction period for generating facilities, utilities must plan to minimize cost over the long term. Therefore, their planning must also include what new generating facilities are needed, when they should be brought into service, and how large they should be.

Neither have we addressed the long-term planning required for the transmission network. Beyond these considerations are the level of electricity prices and the rate structure, which in turn affect the growth and temporal pattern of demand.

Measuring Hydro Rent

It should be noted that we have assumed up to this point that hydro would always be utilized instead of thermal if it were available. But, of course, this depends on its comparative cost.

Above we showed how to measure the total cost of thermal generation at a given capacity over a given period of time. Using this approach (see Figure 2-3), the cost saving that could be realized by displacing thermal with hydro power can be calculated. This cost can then be compared with the fixed and operating cost for the relevant hydro sites to see if hydro use is in fact economical.

The procedure used here to measure hydro rent essentially involves a reversal of this approach. In our case, hydro exists as part of the system, and we measure the rent as the difference between the cost of the system as it exists with hydro and the cost that would be incurred if the hydro were to be replaced with the least costly thermal generating technologies.

It can be seen from this example that the economic rent associated with hydro depends on a number of factors: the characteristics and cost of the hydro-thermal system; the pattern of demands over time, which influences how the hydro resources can best be utilized; and the relative costs of the various thermal technologies available to replace the hydro power, depending on its utilization. The economic rent will therefore vary for each hourly component of demand met using hydro. The method employed for measuring economic rent will reflect these differences. It will implicitly estimate the cost saving realized by using hydro to meet each individual component of demand, instead of the least cost thermal alternative means of production.

The foregoing analysis indicates some of the underlying aspects of the interdependencies in the generation of electricity in a mixed hydro-thermal system. Two aspects of this interdependence in particular suggest that the minimum cost of a totally redesigned all-thermal system would be lower than that for an all-thermal system retaining the current structure of thermal facilities.

First of all, there would likely be cost saving opportunities as a result of economies of scale or a better matching of the unit sizes of generating stations. For example, instead of adding totally new nuclear capacity to replace existing baseload hydro, it is likely that lower costs could be achieved by changing station and/or unit sizes of at least some nuclear stations.

Second, the development of the existing generating and transmission system over a period of many years likely includes a number of features that, with the aid of hindsight, are not provided at least cost. These plants perhaps should be replaced, but their capital cost has already been sunk. A completely optimized thermal system that does not contain the normal mistakes made over time would be able to produce and deliver electricity at a lower cost than a modified system substituting thermal for hydro facilities.

Moreover, because hydro sites are often situated at great distances from the location of demand, the cost of transmission facilities and the losses of energy that occur in transmission can be sizable. High voltage transmission has made lower line losses possible but, even so, the net energy available from a distant hydro site may be 8 to 10 per cent less than that produced at source. In contrast, thermal generating stations can generally be located closer to market, so that the cost of transmission lines and line losses are lower. As a result, less thermal generation would be required to provide the same net energy. This reduction in cost must be taken into account if the economic rent on hydro production is not to be overestimated.

Furthermore, very substantial inventories of fuels relative to quantities annually consumed are usually maintained by utilities. Inventory costs tie up funds in the inventories themselves, as well as in the capital and operating costs required to maintain these inventories. These additional costs for thermal generation need to be taken into account in measuring the saving achieved through hydro use.

Economic Versus Financial Costs

To estimate the cost saving made possible by the use of hydro resources compared with the least costly alternative, it is essential that factor costs for the two systems be based on the economic or opportunity costs of the labour, capital, fuels, and other intermediate inputs used in production. The costs of these resources as measured by public electric utilities are in most cases much less than the actual opportunity cost of these resources to the Canadian economy. Hence, using the financial costs as measured by the utility would not yield a conceptually correct measure of the economic saving derived from the use of hydro resources.

There are several reasons why the financial costs of electric utilities differ from the economic costs of the resources devoted to electricity production.

One reason is that, in the case of oil and gas, the cost of these fuels to the utility, measured by Canadian domestic prices, does not reflect their economic opportunity cost as measured by their world prices. Thus, in determining the nature of the generating facilities for an optimal all-thermal system, and in measuring the economic cost of the current and alternative systems, the opportunity cost of all fuels should be used.

Similarly, the opportunity cost of the labour employed in production of electricity, rather than the wages actually paid, should be utilized in developing the economic cost estimates. However, we have not made any adjustment to actual labour costs in our estimates.

The lower financial cost of capital to public electric utilities for the resources employed in production does not fully reflect their actual economic or opportunity cost to the nation, for several reasons.

The debt of public electric utilities is guaranteed by provincial governments, so the risk to lenders and the cost of capital is lower. Without this guarantee, utilities would have to maintain a lower ratio of debt to equity in order to borrow at such attractive rates. The effect is twofold. The utility can charge lower rates, which in turn boosts the quantity of electricity demanded and thus the size of the electric utility. And a more capital intensive means of production will be used to produce any given level of output, since the relative price of capital to fuel (and other inputs) is reduced.

With regard to the cost of equity, public electric utilities are not required to earn an after-tax rate of return on equity comparable with that earned on equity in the private sector. This further reduces the cost of capital to the utility and the rates charged, which in turn increases the level of demand and the size of the system.

Finally, public electric utilities, because they are provincial Crown corporations, are not required to pay federal income tax, and generally do not pay provincial income tax. Thus, even if these utilities were required to earn an after-tax rate of return on equity comparable with that in the private sector, the before-tax rate of return could be less. As a result, through the mutually reinforcing factors of the low cost of capital on the supply side and low prices on the demand side, the amount of capital employed exceeds the level needed for economic efficiency.

Making public electric utilities subject to corporate income tax would not by itself ensure that they would employ capital efficiently. If there is no required rate of return on equity, there is no need to have a net income to be taxed. Even with a required rate of return on equity, loan guarantees would allow the utility to maintain a high debt-to-equity ratio, so there would be less than normal profits to be taxed, given the total amount of capital employed. At a minimum, using capital more efficiently requires earning some "appropriate" rate of return on all capital invested, both debt and equity.

What would be a reasonable before-tax rate of return on invested capital? The rate of return for the economically efficient use of capital should reflect the opportunity cost of this capital to the Canadian economy. Such a rate is referred to as the social opportunity cost of capital, and it is suggested by economists that this rate of return should be required, at a minimum, to justify all public projects on economic grounds. The social opportunity cost of capital, expressed as an annual rate of interest, is composed of the return to fixed capital in the private sector, the cost of delayed consumption as measured by the social rate of time preference, and the cost of foreign funds to the Canadian economy, each component being weighted to reflect the contribution of the marginal demand for capital from each source to the composite rate. Empirical work has produced estimates of a before-tax real rate for the social opportunity cost of capital in Canada at 10 per cent and 7.5 per cent, based on different assumptions. We have used 10 per cent to derive our estimates of hydro-electric rent.[4]

The cost of value assets as measured by the electric utilities on their books also falls short of its social opportunity cost.

For an electric facility under construction, utilities assess the interest carried on a nonproducing investment at the rate at which they can borrow, and not at the higher rate that reflects the social opportunity cost of capital. We have not made any adjustment for this factor in the current system, since estimates of the capital cost for the thermal facilities in the least cost, alternative system do not measure interest during construction at the proper (higher) rate either.

In addition, utilities base their measurement for fixed capital investment on historical value rather than on replacement value at current prices. Therefore, the social opportunity cost of capital applied to the historical value of the capital stock would not measure the economic opportunity cost of these resources. In this study, the annual economic cost of capital employed is derived by applying the social opportunity cost rate to the current replacement value of the net (depreciated) capital stock, and not to its historical net value.

Depreciation, or the estimate of the amount of capital used up in production each year, also is based on historical values of capital, and not on the current replacement value. Therefore, depreciation expense must be adjusted upward as well in order to measure the economic cost of the capital consumed in production.

Inefficiencies in the Current System

To estimate the cost of the least cost alternative system, we will design an optimal system using a planning horizon of 25 years and, most importantly, assume that this system can be put in place instantaneously. Thus, the alternative system that we use as a reference cost is not bound by the legacy of any past errors.

Such, however, is not the case with the current system. Because it has evolved over time and is based on projections that were not always realized, there are cost savings that could be achieved if the system could be rebuilt according to current, revised expectations. These inefficiencies are likely manifested in several ways: a wrong mix of the various generating technologies, nonoptimal unit sizes of generating stations, and excess capacity arising when actual demand growth was less than that forecast.

Ideally, an estimate of the economic rent from hydro production should be based on the difference in cost of the least cost systems both with and without hydro. Unfortunately, we do not have the capability to determine the characteristics and the cost of the least cost system that includes the available hydro generating facilities. Instead, we use the higher economic cost of the current system as the basis for our estimate of the economic rent from hydro use. Thus, our measures of economic rent on hydraulic resources will tend to be underestimates of the true values.

3 Design of an Alternative All-Thermal System

In this chapter, we outline the development of a set of investment and operating plans for an electric generating system to meet the projected demand for electrical energy at least cost, using only thermal electric generating technologies. To carry out such a planning exercise, it is first necessary to forecast the future quantity of energy demanded. Given this forecast, the problem is then one of designing an investment and operating plan that will meet the demand at the lowest present value of capital and operating cost.

As noted at the beginning of Chapter 1, hydro-electric generation is a major source of electricity in four Canadian provinces, namely, Quebec, Ontario, Manitoba, and British Columbia. Although the large hydro-electric generating station at Churchill Falls is located in Labrador, for the purpose of the analysis, it is deemed to be included in the Quebec system. All the other provinces, except Prince Edward Island, have some hydro-electric generating capacity, but these facilities are much smaller in size. Hence, the estimation of the economic costs of an optimal all-thermal electric generating system is only carried out for the four provinces where hydro power is a major source of electric generation.

The traditional method for developing the investment and operating plans for an electric utility is to have systems planners construct a profile of investments in generating plants, based on assumptions concerning the costs of factor inputs and the growth in the demand for capacity and energy over time. A number of constraints concerning the desired level of reserves and required maintenance are also imposed for the development of a viable and low-cost system.

In these analyses, a series of annual load duration curves, such as the one shown in Figure 1-4, is utilized by the planners. Because the generating, transmission, and distribution assets typically have a long life, the problem requires the engineers to compare the costs of alternative generating technologies and sizes of plants over a significant period of time (25 to 30 years). Over this period, the systems planners must also estimate the number of hours that each generating plant will be operated each year, in order to determine the fuel and other operating costs of the system. The system with the lowest present value of the combined fixed and operating costs is the one sought by the systems planners.

This analysis is usually carried out with the use of a number of engineering algorithms and computer simulation models. These enable the systems planners to carry out the estimations through a series of iterations that ultimately yield a solution approximating the configuration of investments and operating plans at least cost.

An alternative approach, and the one used in this study, is based on a combination of minimum discounted cash flows logic and minimum annual production cost rationale. This method and the results derived from it are outlined below. It should be added that the results have also been examined by professional systems planners, and have been judged to be reliable.

Design of Optimal Expansion Plans

More than 90 per cent of a utility's production costs are expenditures on generating, transmission, and distribution facilities and fuel. A power system's total production cost depends critically on how equipment and fuel are arranged in producing electricity to fill the load duration curve. To do this, at least two types of decisions must be made. First, a choice has to be made on what equipment to build through time, based on forecasts of future capacity and energy requirements and prices. Second, at every point in time, it must be decided which of the plants in place will be used, given the relative operating costs of the equipment at that instant. If the systems planners have perfect foresight, then their decision on the type and size of equipment would be the same as the set that they would want to use to minimize the generating cost cumulated over time. However, this is usually not the case. Certain plants may be built for the system based on expected values of demand and costs of inputs that, if prices changed, would not allow the utility system to operate at least cost, even if they dispatched their existing plant and equipment optimally. While in actual practice investment decisions and operating decisions are distinct, in this analysis, we start with the question of how best to dispatch (operate) an electric system at least cost with given forecasts of demand and input prices. After examining the use of different types of equipment used – assuming every type is available to the operator at each point in time – we can then determine whether the pattern of use over time is consistent with an optimal investment strategy for plants, which, once built, remain with the utility until they become economically obsolete.

In order to carry out the optimal dispatching exercise, it is initially assumed that each electric generating facility can be rented for a year and, at the end of the year, the lease can either be renewed or revoked. This allows us to choose the type of technology and size of plant on an annual basis so that, given the prices of inputs, the load curve is filled at minimum cost. This involves the principles outlined in Chapter 2 for choosing the right mix of capital and operating costs to minimize the total generating costs of the utility.

Let us imagine that the load duration curve in Figure 3-1 is divided into many horizontal strips, all with a height of exactly one megawatt of capacity. The length, say, H hours, of a strip will mean that H megawatt hours of energy must be produced to meet the demand. The problem now is one of choosing the type of equipment and number of hours to run each type of equipment, so that there is an optimal stacking of the facilities to meet the demand for electricity.

The optimal stacking exercise can either start from the top down or from the bottom up, and both should lead to the same result. Suppose we start to stack the load duration curve from the top down. Since gas turbines usually have the lowest capital cost and highest fuel cost, we should begin the first megawatt of stacking with gas turbines. As we increase the capacity provided by gas turbines, each successive megawatt of gas turbine power will have to be run longer (the horizontal strip becomes longer) and thus burn more fuel. As we saw in Figure 2-1, there is a point at which the benefit of the cheaper capital cost of gas turbine is exactly offset by the more expensive fuel that it burns. Passing this point, other types of facilities, with a higher capital cost but a lower fuel cost, should be used.

Expressing this trade-off between capital cost and operating cost algebraically, let us denote the annual capital cost (rental price) of gas turbines per megawatt of power by R_g and the fuel cost per megawatt-hour by F_g. Suppose that an oil-fired plant has the next most expensive capital cost at R_o and the next less expensive fuel cost at F_o. Let H denote the duration of a horizontal strip and $H_g{}^*$ the number of hours that the gas turbine facility may be run if it is efficient. The value for $H_g{}^*$ is determined by comparing the extra annual fuel cost of running the gas turbine over that for running the oil-fueled plant, $H_g{}^*(F_g - F_o)$, with the saving in the capital cost of the gas turbine equipment over that for the oil-fired facility, $R_o - R_g$. The number of running hours for gas turbine equipment that equates the extra fuel cost with the capital saving is found by:

$$(3.1)\quad H_g{}^* (F_g - F_o) = (R_o - R_g),$$

or

$$(3.2)\quad H_g{}^* = \frac{R_o - R_g}{F_g - F_o}.$$

Equation 3.1 is thus the optimal stacking criterion; it tells us to install more gas turbines so long as the saving in capital cost outweighs the greater fuel cost. The switch from gas turbine generation to oil-fired generation occurs at the point where the gas turbines are required to operate more than $H_g{}^*$ hours per year. If we let the subscripts c and n denote a coal-fired plant or nuclear plant, respectively, in a similar fashion, we can write:

$$(3.3)\quad H_o{}^* = \frac{R_c - R_o}{F_o - F_c},$$

$$(3.4)\quad H_c{}^* = \frac{R_n - R_c}{F_c - F_n},$$

where $H_g{}^*$, $H_o{}^*$, $H_c{}^* \leqslant 8{,}760$ hours, $R_n \geqslant R_c \geqslant R_o \geqslant R_g$, and $F_g \geqslant F_o \geqslant F_c \geqslant F_n$.

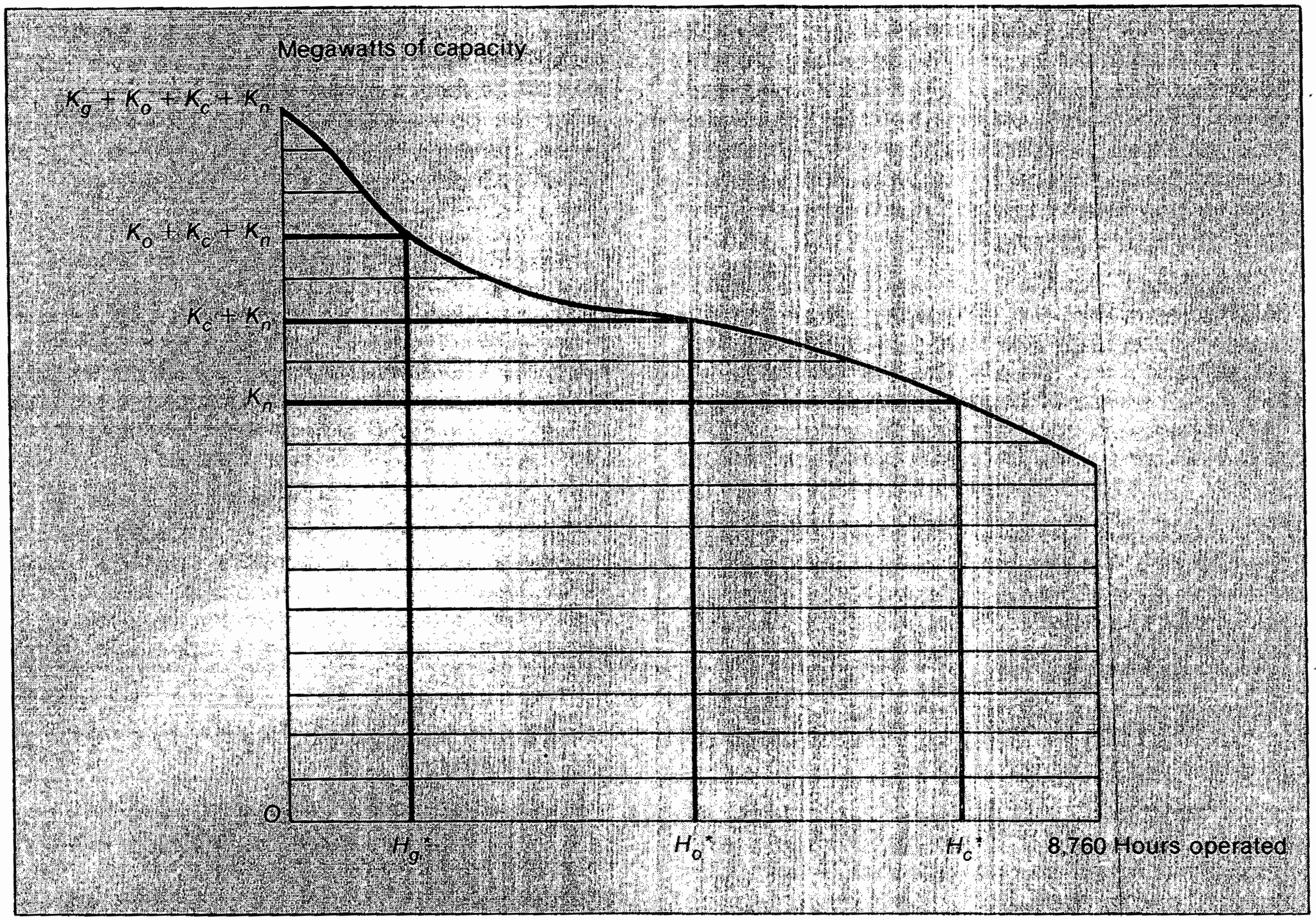
Knowing $H_g{}^*$, $H_o{}^*$, and $H_c{}^*$ and the load duration curve, an optimal stacking of an electric generating system in a given year can be undertaken as shown in Figure 3-1, where K_i denotes the total installed capacity of the i^{th} type of generating capacity, where i refers to the various plant types. The goal of optimal stacking can thus be expressed as minimizing the total systems costs, such that:

$$(3.5)\quad min\left\{\sum_i R_iK_i + \sum_i F_iH_i\right\}.$$

The assumption that the different types of generating capacity could be rented at an annual capital cost per megawatt allows an optimal stacking exercise to be undertaken each year. This procedure provides answers annually to both the optimal amounts of capital of different types and the fuels that should be utilized. However, the central analytical problem of systems planning is that this optimization exercise must take place under the constraint that, once equipment is purchased, it cannot be sold and, in addition, the relative prices of capital and fuel may change over time.

Figure 3-1

Optimal Stacking for a Given Annual Load Duration Curve



It may be the case that the best mix of plants, as indicated by the annual optimal stacking exercise, is the least cost combination, and that these plants do not violate the constraint imposed. If we find that the mix of plants chosen in the early years is such that the optimal mix in later years would have excluded one or more of these plants, then we would need to place additional constraints on the acceptable configuration of plants as determined by the optimal stacking criterion. At the same time, a number of adjustments can be made so that the parameters of the optimal stacking problem reflect future as well as present economic prices and costs.

One such adjustment is to use factor prices in the optimal stacking exercise to reflect a weighted average of the annual prices expected to exist over the useful life of the equipment. These prices would replace the current prices used. For example, oil prices used in the stacking of gas turbine generators in year 1 are estimated as:

$$(3.6)\quad \bar{F}_{g1} = \sum_{t=1}^{n} \frac{F_{gt}\, Q_{gt}}{(1 + r)^t} \Bigg/ \sum_{t=1}^{n} \frac{Q_{gt}}{(1 + r)^t},$$

where Q_{gt} is the projected quantity of electricity generated t years from now by a plant that is being considered as an addition to the utility. The gas turbine is expected to operate for n years, and F_{gt} is the expected price of oil in year t per unit of electricity generated.

Following Equation 3.6, long-run prices can be calculated for the fuel and annual capital cost for each type of capital equipment in the years covering the planning horizon of the utility.

Even using the long-run prices of inputs rather than their current values to determine the least cost set of stacking through time, it is possible that the optimal stacking routine will recommend a profile of generating plants that is inconsistent with a realistic investment strategy. Such a strategy would not allow the costless elimination of plants that are introduced in a given year but are not required at a later date. In the application of the methodology to the four Canadian electric utilities studied here, the situation never arose where, in a later year, less of a particular type of plant was required to optimally meet the forecasted demand than was stipulated in an earlier year. If this were to happen, however, a number of further calculations would be required.[1]

In Appendix Table A-1, the values for the fuel cost per megawatt-hour of electricity generated are presented for 1979 and 1980. The values for 1979 reflect end-of-year values. In this analysis, it is assumed that fuel costs will just maintain their real 1979 values over time. An inflation factor of 10 per cent a year is applied to obtain current year nominal prices.

To obtain these values, the heat rate of each of the plants (Table A-2, column 3) is used along with the economic price of the fuel delivered to the utility. The fuel cost values reported in Table A-1 are the values corresponding to the plants found to be the optimal size for use in each province. Because plants of different sizes have different heat rates, for each kind of fuel, the cost per megawatt-hour of electricity generated also varies with plant size.

The unit capital costs per kilowatt of capacity are presented in Table A-2, column 1, for electric generating plants of various types and sizes. Fixed operating and maintenance costs for these plants are reported in column 2. Using a real economic cost of capital of 10 per cent and the appropriate depreciation rate for the plant, annual rental costs of capital can be estimated for each type of plant. These annual capital rentals and their corresponding fuel costs are used to determine the set of plants and the operating schedules needed to allow the utility to supply the electricity demanded at least cost.

Prior to computing the final optimal system, the load duration curves of the system through time are prestacked using these prices. Maintenance schedules are also selected so that the loss of load probability (LOLP) of the system can be calculated. In these estimations, this calculation is based on the loading sequences of the optimized generating units and their forced outage rates. Once the LOLP calculations for the system are done, the reserve margin is set to satisfy a loss of load reliability criterion of one day lost in ten years. The reserve margins are defined here as the percentage of net generating capacity available to meet the primary demand at the generating units.

The LOLP is then recalculated by an economic dispatch model using the actual prices for the different fuels in the year of operation to determine the most efficient way to operate the equipment available to the system. If the LOLP of any year exceeds the prescribed reliability criterion, the reserve margins and the selection of plants are then recalculated using the optimal stacking criterion, and the economic dispatch model is again used to estimate operating rates and costs of the system for each year.

The economic dispatch model uses the selected generating units to perform hourly dispatch of the loads provided by the hourly forecasts from the projected load curves. This dispatch is carried out using the traditional least cost, first-loaded method. The units employed in a given period are restricted by unit availability constraints as well as by maintenance constraints.

In determining the maintenance schedule for the plants in a given year, an attempt is made to equalize the twelve-month peak demands including maintenance. Instead of using a computer model subroutine dealing with the increased maintenance levels during the first few years of a unit's operation, mature planned and forced outage rates are used throughout. The requirements for spinning reserves and the restriction on cycling units are also considered in the dispatch model.

Selecting the optimal generating equipment each year and using the economic dispatch model to determine operating rates and costs, we are able to estimate the total financial and economic costs for the system for each year.

Results of Estimation of All-Thermal Systems

Based on the projected load duration curves and factor prices, all-thermal electric generating systems were designed for Quebec, Ontario, Manitoba, and British Columbia. While the system design was carried out for an extended period, we report in Table A-3 only the 1979 configuration of generating equipment and energy produced using thermal electric generating technologies.

From Table A-3, we see that, in Quebec and Ontario, nuclear plants could be used intensively to replace hydro generating facilities. In all cases, coal-fired stations would be used instead of large oil-fired generating facilities. However, in Manitoba and British Columbia, only coal generating stations and gas turbines would be used.

In these two provinces, coal is a lower-cost source of electrical energy than is nuclear fuel, but for different reasons. In Manitoba, the electric utility system is quite small and, hence, the reserve requirements imposed by nuclear fuel are such as to make it less attractive for generation than coal. British Columbia has large deposits of low-cost coal. As a result, the delivered price of coal is low enough so that, even in such a large system, coal-fired stations are less costly than nuclear stations.

Turning to Table A-4, we find that the system load factors for each province are quite close. The load factor for the Quebec system at 65.2 per cent is the lowest, with that of Manitoba being the highest at 70.1 per cent.

As expected, the capacity factors of coal plants in Manitoba and British Columbia are much higher than those in Quebec and Ontario. This arises because coal plants are used as the baseload generating facilities in Manitoba and British Columbia, while nuclear plants provide the baseload in Quebec and Ontario. The most surprising feature is the great difference in the capacity factors of gas turbine plants in Quebec and Ontario, on one hand, and in Manitoba and British Columbia, on the other. In Quebec and Ontario, the capacity factors are only 4.5 and 7.3 per cent, respectively. In these two systems, gas turbines are used mainly for meeting reserve as well as providing peaking capacity. However, in Manitoba and British Columbia, gas turbines are used at 39.6 and 34.5 per cent of their capacities, respectively. In these two provinces, gas turbines are used not only for reserve and peaking capacity, but in fact are utilized fairly extensively throughout the year.

The generating costs for the utilities have been estimated for each of the major cost categories, and are reported in Table 3-1 for 1979. We find that the greater use of gas turbines in Manitoba and British Columbia results in significantly higher unit generating costs for the systems as a whole. From the last row of Table 3-1, we find that the unit generating costs in Quebec and Ontario are almost identical at 29.4 and

Table 3-1

Production Costs

Estimated total and unit generating costs for alternative all-thermal electric generating systems in four provinces, 1979

	Quebec	Ontario	Manitoba	British Columbia
		(Thousands of dollars)		
Generation capital				
Nuclear	1,724,480	1,616,700	–	–
Coal	551,250	441,000	247,080	530,880
Gas turbine	49,600	31,000	10,170	45,980
Total	2,325,330	2,088,700	257,250	576,860
Fixed operating and maintenance cost				
Nuclear	48	45	–	–
Coal	56	44	34	49
Gas turbine	1	1	–	1
Total	105	90	34	50
Variable operating and maintenance cost				
Nuclear	177,160	163,100	–	–
Coal	26,960	19,800	19,200	44,090
Gas turbine	4,290	4,300	4,800	24,620
Total	208,410	187,200	24,000	68,710
Fuel cost				
Nuclear	186,020	171,300	–	–
Coal	391,230	275,400	212,500	306,650
Gas turbine	140,920	142,100	200,551	807,800
Total	718,170	588,800	413,051	1,114,450
Total generating cost	3,252,020	2,864,800	697,680	1,760,070
		(Mills per kilowatt-hour)		
Unit generating cost	29.4	29.2	44.7	42.7

SOURCE Estimates by authors.

29.2 mills per kilowatt-hour, respectively, whereas in Manitoba the unit generating cost is 44.7 mills and, in British Columbia, it is 42.7 mills per kilowatt-hour. While these are the least cost, all-thermal generating system configurations, we find that, as a result of the size and shape of the load duration curves in Manitoba and British Columbia, the optimum generating system contains a great deal more gas turbine capacity, which in turn is utilized to a much higher degree than in the other provinces. Although gas turbines are more efficient than any other mode of generation for relatively short running times, they still result in a higher generating cost than is the case in Quebec and Ontario.

This range of average generating costs, between Ontario and Quebec on one hand, and Manitoba and British Columbia on the other, indicates the considerable potential for economies of scale existing for electric utilities that rely primarily on thermal generating facilities.

The various components of generating costs are utilized in Chapter 4 to estimate the total systems cost of the all-thermal alternative. It is these systems costs, when compared with the economic costs of the current hydro-thermal generating system, that provide us with the estimate of the economic rent derived from hydro-electric generating facilities for 1979.

4 Estimating the Economic Rent on Hydro-Electric Production

This chapter outlines the approach taken in estimating the economic rent on hydro-electric production as the difference between the economic cost of the current system and that for a least cost, all-thermal system. In making these calculations, a number of simplifying assumptions have been made. In particular, when information was lacking, assumptions have been made that tend to bias downward the estimates of the economic cost of the all-thermal system and bias upward the economic cost of the current system. This has the effect of reducing the estimated value of hydro rent.

The estimation of the economic cost of the total system is carried through to the retail level – that is, for generation, transmission, distribution, and administration. There are a number of reasons for doing this.

First, a consistent set of data on assets and costs is available from Statistics Canada for the total system in each province. Second, as electricity prices are usually quoted at the retail level, the economic costs are estimated at that level to provide easier price comparison.

Economic costs for the current and all-thermal systems have been estimated for all electric utilities, both public and private. As a practical matter, a comprehensive set of data for capacity, energy, fuels, assets, liabilities, revenue, and expenditures is provided by Statistics Canada for the total utility system in a province, but does not necessarily distinguish between public and private production. This aggregation would seem to be the most meaningful measure of economic rent for public policy purposes. In any case, for the four provinces analysed, public utilities constitute almost all of the electric utility sector.

The Economic Cost of the Current System

Appendix Tables B-1 to B-3 provide a detailed account of our estimating procedures and the specific sources of the data utilized. In this section, we outline the basic approach taken, together with any important assumptions.

We have estimated the annual economic cost of the current system as the sum of:

- the economic depreciation and annual social opportunity cost of net fixed assets at 1979 prices;
- operating, maintenance, and administration costs including the cost of fuels consumed valued at current opportunity prices; and
- the annual social opportunity cost of net current assets including inventories and other investments.

The latter component of cost is often ignored in measuring total economic cost, and, while not large relative to the cost of fixed capital in the case of electric utilities, it can be significant in many industries.

More specifically, the economic cost of the current system is estimated as the sum of the following:

- the economic depreciation and annual social opportunity cost of the net current replacement value of the capital stock of facilities used for generating electricity;
- the economic cost of fuels used for generation;
- the operating and maintenance expense for generation, consisting of fixed and variable cost components;
- the cost of purchased electricity (which, in the case of electricity purchased by Quebec from Churchill Falls, is measured as the economic cost of producing this power);
- the economic depreciation and social opportunity cost of the net current replacement value of the capital stock needed for power transmission;
- the economic depreciation and the social opportunity cost of the net current replacement value of the capital stock for the distribution network;
- the operating and maintenance expense for transmission;
- the operating, maintenance, and administration expense for purposes other than generation and

transmission, that is, distribution and general administration;

- the economic depreciation and social opportunity cost of the net replacement value of other fixed assets; and

- the social opportunity cost of net current assets and other investments.

The estimating methods employed for each of these components are outlined below.

Generation Capital

The economic cost of capital for generating facilities consists of economic depreciation and the social opportunity cost of the net replacement value of the capital stock. An annual rate of economic depreciation and the social opportunity cost of capital, for which we use 10 per cent a year, must be applied to the net replacement value of the capital stock valued at 1979 prices.

To estimate the net replacement value of this capital stock, we start with the value of total gross investment in these assets at historical costs. This information is available from Statistics Canada based on information provided by the utilities. In addition, the National Wealth and Capital Stock Section of Statistics Canada derives estimates of the net value of capital stock by industry and province at replacement prices for each year based on historical values of investment each year, investment price indexes, and economic depreciation rates based on the estimated useful lifetimes of the assets. The ratio of net fixed capital stock at current prices, for a given sector and province, to the value of gross capital stock measured at original or historical prices provides an index of price change and a correction for depreciation. This index can be used to adjust the gross historical value of capital stock to an estimated net value of capital stock at current prices.

The smallest sectoral aggregation available at the provincial level to include electric utilities is the Miscellaneous Utilities Industry, which also includes natural gas and water distribution systems. However, the electric utility subsector constitutes the major proportion of this sector in the four provinces under study. Because the Miscellaneous Utilities Sector includes other subsectors as well as the electric utility subsector, the price ratio or index for the former is not precisely appropriate for the latter, but it is likely to be approximately so, given the relative size of the electric utility subsector within Miscellaneous Utilities.

The capital stock data base constructed by the National Wealth and Capital Stock Section of Statistics Canada also contains estimates of economic depreciation for each year in current dollars of that year by sector and province. The economic depreciation rate is estimated as the ratio of economic depreciation to the net replacement value of the capital stock in a given year for Miscellaneous Utilities in each of the four provinces. We then apply this depreciation rate to the estimated net replacement value of capital stock for generating facilities in current prices in a given year to estimate the economic depreciation of this capital stock for the year.

A 10 per cent rate is applied to the net replacement value of this capital stock in each year to reflect the social opportunity cost of capital. This is added to the economic depreciation to yield the total annual cost of capital for generating facilities for the year.

Fuel Costs

The estimated economic cost of fuels consumed by generating facilities, as shown in Table B-1, is derived from the quantities of fuels consumed and the estimated opportunity prices of these fuels.

Generation Operating and Maintenance

Operating and maintenance costs for the various types of generating facilities are estimated as the sum of a fixed cost per kilowatt of capacity and a variable cost per kilowatt-hour of energy generated.

Cost of Purchased Electricity

With the exception of electricity purchased by Quebec from Churchill Falls, the actual cost of electricity purchased from other provinces, industrial establishments, and the United States is taken as an estimate of the economic cost of this power. This is likely to underestimate the true economic cost, and thus has the effect of inflating our estimates of hydro rent. The effect is likely only significant for the utilities in British Columbia, which purchased about 14 per cent of their total supply of energy in 1979. Estimating the economic cost of this purchased power would have required extending this economic costing exercise to the vendors of this power.

In the case of electricity purchased from Churchill Falls by Quebec, in view of the very large quantity involved, we estimate the economic cost of this power by estimating the economic cost of Churchill Falls directly and applying the cost per kilowatt-hour of energy produced to the energy sold to Quebec. The derivation of this estimate is presented in Tables B-2 and B-3.

Transmission Capital

The method and parameters (that is, the price index and depreciation rate) employed to estimate the economic cost of capital used for transmission of power are identical to those for the capital used for generating facilities.

Distribution Capital

The method and parameters employed to estimate the economic cost of capital used for distribution are identical to those for the capital used for generating facilities and power transmission.

Transmission Operating and Maintenance

The operating and maintenance costs for transmission are based on unofficial cost estimates, which are obtained directly from the utilities.

Distribution Operating and Maintenance

The costs for operation and maintenance of the distribution network and other general administration are derived from the total of such costs provided by Statistics Canada (which include actual fuel costs) less the actual fuel cost and less the operating and maintenance cost for generating facilities and power transmission, as estimated above.

Other Fixed Assets

Data on the value of other fixed assets are provided by Statistics Canada in two categories: "other property and equipment" and "other fixed assets, less depreciation." The former are provided at original cost before depreciation, while the latter are valued at historical prices net of depreciation.

For the former, the net replacement value of the capital stock of other fixed assets is estimated using the same price index as for the capital stock for generation, transmission, and distribution. In the case of the latter, because it is valued on a net basis, it is necessary to derive a net value at current prices using a price index, which is formed as the ratio of the net current value of capital stock at current prices to the net (rather than the gross) value at historical prices for the Miscellaneous Utilities Industry for each of the four provinces.

Once both types of capital have been valued on a net basis at current prices and summed, economic depreciation is estimated by applying the same depreciation rate used previously. The social opportunity cost of this capital based on a real rate of 10 per cent is then added to the economic depreciation to yield the total economic cost of these two categories of fixed assets.

It should be noted that the value of construction in progress is not included in the calculation of the capital cost of fixed assets, as these facilities are not in use to meet current demand. The capital cost of facilities for the production of heavy water is not included either, as this would involve double counting, since the heavy water initially installed in nuclear reactors is included in their capital cost. The cost of additional heavy water installed in reactors on an ongoing basis is included in operating and maintenance cost for nuclear generation.

Net Current Assets and Other Investments

The social opportunity cost of holding net current assets and other investments is measured by applying the social opportunity cost of capital to the value of these assets.

The Economic Cost of the Least Cost, All-Thermal System

Four important factors must be taken into account to estimate the economic cost of the all-thermal system. They are:

- the annual cost of generation using thermal sources only, which includes depreciation, the social opportunity cost of generation capital, operating and maintenance cost for generation, and the cost of fuels consumed at current opportunity prices;

- a downward adjustment of the cost of generation by a factor to reflect the lower level of transmission losses that would occur with thermal rather than hydro generation;

- the social opportunity cost of the fuel inventories required with an all-thermal system; and

- a reduction in transmission costs, both capital and operating, which would occur with thermal rather than hydro generation, since thermal generating facilities would likely be located closer to markets.

Appendix Tables B-4 and B-5 provide a detailed account of our estimating procedures. In this section, we describe the basic approach taken, and discuss the important assumptions we made.

We estimate the economic cost of the least cost, all-thermal system as the sum of the following.

- costs of generating facilities including capital costs (consisting of the economic depreciation and social opportunity cost of generation capital at 10 per cent a year), the cost of fuel consumed at opportunity prices, and operating and maintenance costs;

- the social opportunity cost of holding fuel inventories;
- the social opportunity cost, at 10 per cent a year, of other net current assets (excluding inventories) and other investments;
- the capital cost of other fixed assets (other than fixed capital costs for generation, transmission, and distribution);
- the capital cost for distribution facilities;
- the operating, maintenance, and administration cost, other than for generation and transmission; and
- the capital, operating, and maintenance cost for transmission.

The procedures and assumptions underlying these estimates are outlined below.

Generation

The estimated cost of the least cost, all-thermal generating system presented in Chapter 3 is based on the annual hourly load data obtained from the utilities. The energy demanded according to these load curves, however, is not necessarily equal to the amount needed to meet demand under the current system (for which the economic cost has been estimated). It is thus necessary to derive an estimate of the quantity of energy generated by an all-thermal system that would provide the same quantity sold under the current system, so that the economic costs of the two systems are estimated on a consistent basis.

The main difficulty in developing an estimate for the energy generated from an all-thermal system to equal that from the current system lies in the lower amounts of energy lost in transmission experienced by such an all-thermal system. However, it is not possible to estimate with a high degree of accuracy what those losses would be.

To estimate these losses, we assume that the difference between the quantity of energy generated (and purchased) and the quantity of energy sold to users is 50 per cent greater for hydro than for thermal generation, or, equivalently, that total losses for thermal generation are two-thirds those for hydro generation. We believe that this assumption results in an overestimation of the reduction in losses that could be realized for thermal relative to hydro generation, for the following reasons. First, a significant proportion of the difference between energy generated (and purchased) and energy consumed occurs in the distribution system, and these losses would likely continue with thermal in place of hydro generation. Second, while transmission line losses tend to increase with distance, losses for distant hydro sites can be significantly reduced using high-voltage transmission lines.

In order to estimate what amount of energy from thermal generating facilities would equal the amount of "salable" energy generated by the current system (see Table B-5), we must first determine the quantity of "salable" energy, which is the amount of useful energy sold (or able to be sold). We include primary and secondary sales, but exclude energy exchanged. We also determine the proportion of energy lost and unaccounted for. Knowing the proportion of hydro generation in the total supply, assuming a ratio of 1.5 for losses from hydro over thermal generation, and measuring the actual loss ratio for the present total system allows us to derive an estimate of the loss ratio for all-thermal generation by the utilities in each province. The salable energy and this thermal loss ratio are then utilized to derive an estimate of the amount of energy required for an all-thermal system.

The economic cost for the all-thermal generating system must be adjusted by the ratio of the energy required derived above to the energy demand assumed in Chapter 3. As indicated in line 3 of Table B-4, this ratio differs notably from unity for the three provinces other than Quebec. A strictly proportional adjustment (that is, assuming the same cost per kilowatt-hour of energy generated) is not likely to be precisely accurate over such a wide range but, for the sizes of the systems under study, it is likely to be approximately so.

Fuel Inventory

The value of inventory and advance payments per megawatt-hour of generation for the various fuels are based on the values obtained from Ontario Hydro's *Statistical Yearbook* for 1979. The advance payments costs are included along with the inventory costs based on the supposition that they are a substitute for holding inventories for the purpose of maintaining security of supply.

Note that we have not been able to isolate capital and operating costs for inventory facilities. Some, but likely not all, of these costs may be implicitly included in the generating costs used in Chapter 3. Thus, our estimates of the total cost of fuel inventories for the all-thermal system are likely to be underestimated.

The megawatt-hours of generation for each type of fuel are based, in the first instance, on the results obtained for the least cost, all-thermal system developed in Chapter 3. The value of this inventory and advance payments is then adjusted proportionately to accord with the total amount of energy required for the all-thermal system (instead of the energy demanded, as assumed in Chapter 3), as described above. The total annual inventory cost for this adjusted value of assets is then calculated by applying a social opportunity cost of capital of 10 per cent a year.

Other Net Current Assets and Investments

For the three provinces other than Ontario, the economic cost of other net current assets and investments is the same as shown on line 69 in Table B-1. For these provinces, it has been implicitly assumed that fuel inventories in the current system are negligible, because the utilities are based almost exclusively on hydro generation. In the case of Ontario, the value of these assets in the current system is adjusted downward by eliminating the value of fuel inventory and advance payments, as given in Ontario Hydro's *Statistical Yearbook*.

Other Fixed Assets

The capital cost of other fixed assets is the same as given in line 55 of Table B-1.

Distribution Facilities

The capital costs of distribution facilities are the same as those in line 44 of Table B-1.

Distribution Operating and Maintenance

The operating, maintenance, and administration costs for distribution facilities and for general administration are the same as those given in line 51 of Table B-1.

Transmission

We have invoked what we believe to be a high estimate for the saving in capital and operating and maintenance costs for transmission that could be realized with thermal as opposed to hydro generation, for the same reasons that we indicated in the case of transmission line losses. In this case, we have assumed that the cost for transmission (including capital and operation and maintenance) for thermal capacity would be one-half the cost for hydro capacity. The estimating procedure employed is similar to that used to estimate transmission line losses.

Summary of the Estimates

The results of our estimates are summarized in Table 4-1.

We estimate that the economic rent on hydro production for the four provinces are $1,874 million for Quebec, including Churchill Falls, $753 million for Ontario, $522 million for Manitoba, and $819 million for British Columbia.

On the basis of "salable" hydro energy per kilowatt-hour, the economic rent estimates are 19.16 mills in Quebec, including Churchill Falls, 20.40 mills in Ontario, 29.39 mills in Manitoba, and 33.26 mills in British Columbia.

For comparative purposes, the actual revenues per kilowatt-hour of energy sold are also presented in Table 4-1. The revenue per kilowatt-hour as a share of the economic cost per kilowatt-hour of the current system indicates the extent to which electricity is underpriced as a result of the use of financial rather than economic criteria that exclude the hydro rent. The percentage varies from 51 in British Columbia to 75 in Quebec. The actual revenue per kilowatt-hour as a share of the economic cost per kilowatt-hour of the least cost, all-thermal system is a measure of the reduction in price as a result of the combined effect of financial versus economic costing and the fact that hydro rent is passed on to users. This ratio is 44 per cent in Quebec, 57 per cent in Ontario, 34 per cent in Manitoba, and 33 per cent in British Columbia. The high ratio for Ontario reflects the relatively low proportion of hydro generation in that province.

These results are point estimates about which there are, of course, confidence intervals. We have cautioned that our estimates of hydro rent have been derived as a residual between two costs; as such, percentage changes in either or both of the costs would tend to magnify percentage changes in the rent estimates. These estimates are also sensitive to such factors as fuel prices, assumptions regarding changes in transmission costs for an all-thermal system, and the discount rate.

The discount rate is a particularly important variable because capital costs contribute a high proportion of total costs even in the all-thermal systems. (For example, capital costs accounted for about 80 per cent and 53 per cent of the estimated economic costs of the existing system and of the least cost, alternative all-thermal system, respectively, in British Columbia.) Sensitivity analysis for the discount rate would involve both a redesign of the least cost, alternative system and re-estimation of the opportunity cost of capital inputs.

We have not performed a sensitivity analysis for either fuel prices or the discount rate. A reduction in fuel prices would most likely result in a reduction in the rent estimates, particularly since it would reduce

Table 4-1

Summary of Electricity Costs, Revenues, and Hydro Rent, Four Provinces, 1979

	Quebec	Ontario	Manitoba	British Columbia
		(Megawatt-hours)		
Amount of energy sold	100,525,446	105,056,065	18,101,301	29,324,924
Amount of hydro energy sold	97,812,791	36,907,860	17,753,065	24,626,965
		(Thousands of dollars)		
Total cost of energy sold:				
Current system	2,630,092.9	4,092,558.6	672,765.8	1,418,655.3
All-thermal system	4,504,516.8	4,845,391.7	1,194,437.7	2,237,734.4
Difference (hydro rent)	1,874,423.9	752,833.1	521,671.9	819,079.1
Total revenue from energy sold	1,970,355.0	2,751,890.0	401,302.0	728,662.0
		(Mills per kilowatt-hour)		
Unit cost of energy sold:				
Current system	26.163	38.956	37.167	48.377
All-thermal system	44.810	46.122	65.986	76.308
Difference (hydro rent)	18.646	7.166	28.820	27.931
Hydro rent relative to hydro energy sold	19.163	20.398	29.385	33.259
Revenue from energy sold	19.601	26.371*	22.170	24.848
		(Per cent)		
Revenue as a share of current system cost	74.92	67.69	59.65	51.36
Revenue as a share of all-thermal system cost	43.74	57.18	33.60	32.56

*701,925 megawatt-hours of energy supplied to heavy water plants and construction projects is subtracted from total amount of energy sold in determining revenue per kilowatt-hour.

SOURCE For energy sold, see Appendix Table A-5, lines 7 and 8; for current system cost, see Appendix Table A-1, line 70; for all-thermal system cost, see Appendix Table A-4, line 20; for revenue, see Statistics Canada, *Electric Power Statistics. Volume 2. Annual Statistics*, Statistics Canada cat. no. 57-202, 1979, Table 5, line 28.

the cost saving arising from the availability of hydro generation.

The effect of a reduction of the discount rate on the rent estimates is not as clear-cut. First, it would result in a shift towards more capital intensive technologies for the all-thermal system. Second, capital costs constitute a smaller proportion of the cost of an all-thermal than of a mixed hydro-thermal system. It is therefore not possible to generalize what effect a change in this variable would have on the resulting comparative values of capital cost for the two systems, and thus on the rent estimates.

Economic Rent on Electricity from Churchill Falls

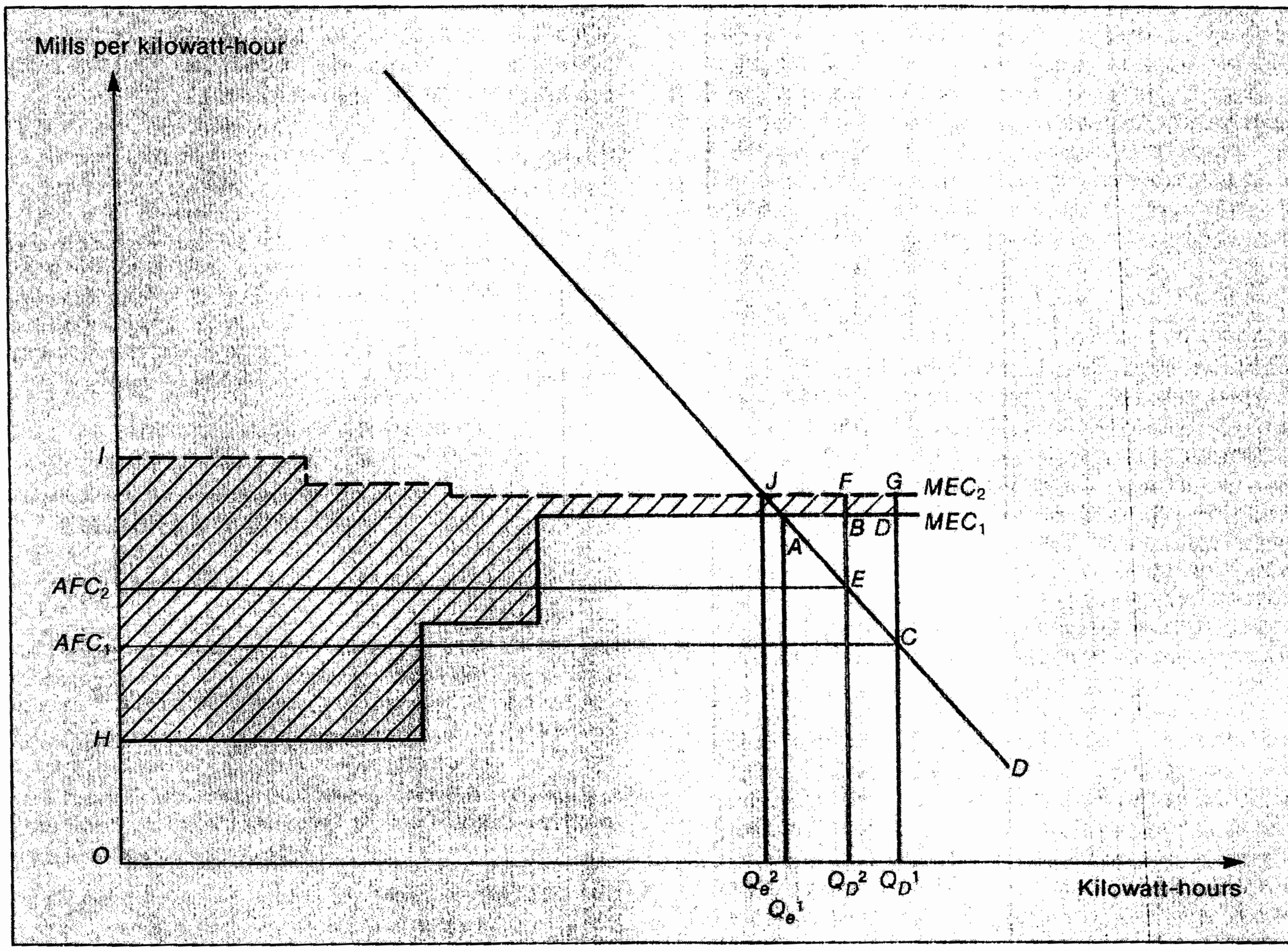
Table B-6 presents the derivation of an estimate of the economic rent on the energy purchased by Quebec from Churchill Falls, which is included above in the estimate of the hydro rent for Quebec. This rent estimate of 18.51 mills per kilowatt-hour is based on the assumption that Quebec would use nuclear generation to replace the power purchased. Hence, the estimate of the economic rent per kilowatt-hour of salable hydro energy generated within Quebec is 19.48 mills, compared with 19.16 mills including Churchill Falls. For 1979, we estimate the total value of the economic rent on the energy from Churchill Falls sold to Quebec to be approximately $583 million.

Higher Electricity Prices and Hydro Rent

The value of the economic rent arising from the hydro sites has to this point been estimated as the difference between the total economic cost of producing the quantity of electricity currently demanded using an all-thermal generating system, and the total economic cost of the existing system with its hydro sites. This is shown schematically in Figure 4-1 as shaded area *IGDH* between the marginal economic cost curve of the alternative all-thermal system, MEC_2, and the marginal economic cost curve of the existing system, MEC_1.

Figure 4-1

Measuring Economic Rent



Because public electric utilities generally price electricity on the basis of their average financial costs of production, not their marginal economic costs, they charge a price for electricity to their customers that is lower than the long-run marginal economic cost of production. The financial costs of the utilities are lower than their economic costs, because these publicly owned corporations pay little if any tax and are able to maintain very high debt-to-equity ratios, while still paying low rates of interest, as their debt is guaranteed by provincial governments.

As shown in Figure 4-1, if a utility prices its output at its marginal economic cost, then the quantity demanded will be equal to $Q_e{}^1$. However, since the price charged is the average financial costs of AFC_1 only, the quantity demanded under the current system will be $Q_D{}^1$. Under the all-thermal alternative system, marginal economic cost pricing would result in $Q_e{}^2$ of electricity being demanded while average financial cost pricing at AFC_2 would lead to $Q_D{}^2$ being demanded.

In measuring the value of the hydro site rent, the question then is: Which quantity of electricity demanded is the appropriate one to use? Because the presence or absence of hydro sites will not change the policy adopted by electric utilities of pricing electricity at its average financial costs, the relevant quantities for evaluating hydro rent are either $Q_D{}^1$, the quantity demanded under the current system, or $Q_D{}^2$, the quantity demanded using the all-thermal system. If the hydro sites are all inframarginal, then the difference between the marginal costs, and hence the incremental value of rent, between quantities $Q_D{}^2$ and $Q_D{}^1$ will be very small. This is likely to be the case for Ontario, where present expansion of the utility has for some time been in the direction of thermal generating plants. The incremental hydro rent is also expected to be rather small between quantities Q_D^2 and Q_D^1 for an all-hydro system, where the costs of current expansion of hydro sites are close to that of alternative thermal generating facilities. In Figure 4-1, the decrease in rent caused by the reduction in the quantity demanded from Q_D^1 to Q_D^2 is shown as the rectangle *BFGD*. This is the amount by which the analysis reported previously in this chapter overstates the value of the rent to the hydroelectric sites, if one uses Q_D^2 as the quantity of electricity demanded under the all-thermal system.

In this study, the impact of the higher prices required to finance an all-thermal alternative on the quantity of electricity demanded is estimated for the Ontario utility. Using a real financial cost of funds of 3 per cent, the average financial costs for the all-thermal alternative is estimated to be 18 per cent higher than for the current system. Using an annual load simulation model to measure the response of electricity demand to price change, it is estimated that 15 per cent fewer kilowatt-hours of electricity would be demanded under the alternative system.[1] The revised demand forecast is then used to recalculate the economic cost of an all-thermal system that would meet this set of electricity demands at the lowest cost of production. It appears that the average economic costs for the revised all-thermal system are less than three-tenths of a mill per kilowatt-hour lower than under the initial all-thermal system, which is designed to generate 15 per cent more electricity. The near constancy of the average economic costs of electricity over a 15 per cent change in output would indicate that, at the level of output of the Ontario Hydro system, the marginal economic costs of expanding the system are also fairly constant. Hence, there is likely to be little difference between the estimated value of the economic rent on the hydro sites at the two levels of output.

In conclusion, our hydro rent estimates for Quebec, Manitoba, and British Columbia should be adjusted downward, because of the demand adjustment to be made under a higher-cost, all-thermal system. But we suggest that the upward bias on this account is not likely to be large in relative terms. Furthermore, the systems in these provinces had an excess capacity in 1979; consequently, their current production costs were higher than necessary. This factor provides a downward bias in the estimates of the economic rent reported here. While we cannot be certain, we suspect that this downward bias is larger than the former upward bias, with the consequent result that our rent estimates remain on the low side. Thus, in the remainder of this study, we use the hydro rent estimates developed in this chapter, which are developed by using the quantities of electricity demanded under the current system.

Comparison of Results with a Previous Study

We do not make a detailed attempt to account for the large differences between our estimates of hydro rent and those developed by Bernard, Bridges, and Scott as presented in Table 4-2. While the conceptual approaches are similar, the empirical approaches and the data employed are quite different.

Table 4-2

Comparison of Hydro Rent Estimates for 1979

	Bernard, Bridges, and Scott	Zuker and Jenkins
	(Millions of dollars)	
Churchill Falls	377	583
Quebec	880	1,291
Ontario	215	753
Manitoba	108	552
British Columbia	1,059*	819
	(Dollars per megawatt-hour)	
Churchill Falls	11.3	18.5
Quebec	9.9	19.5
Ontario	5.1	20.4
Manitoba	5.3	29.4
British Columbia	25.9*	33.3

*No nuclear generation.

SOURCE J. T. Bernard, G. E. Bridges, and A. D. Scott, "An Evaluation of Potential Canadian Hydro Electric Rents," Department of Economics Resource Paper 78, University of British Columbia, Vancouver, February 1982; and estimates by authors.

While it would have been comforting to be able to explain away the differences, we are pleased that other estimates, albeit different ones, have been developed. Hopefully, this will encourage discussion of the conceptual and empirical issues involved.

5 Estimating the Provincial Distribution of Hydro-Electric Rent on the Basis of Consumption

Based on the theory of equalization developed by Boadway and Flatters (1982), the economic rent on hydro-electricity should be subject to equalization. The rent, however, is not collected by provincial governments but rather is distributed to users. Thus, to apply the Boadway-Flatters scheme to hydro-electric rent in Canada under these circumstances, it is necessary to equalize hydro rent on the basis of consumption, because this is how these fiscal benefits are distributed.

In the previous chapter we developed estimates of hydro-electric rent for four provinces (as well as the rent on electricity purchased by Quebec from Churchill Falls) on the basis of production. In this section, we now derive estimates of the distribution of hydro rent by province on the basis of consumption for 1979.

These estimates are based on the simplifying assumption of proportionality. For example, if an electric utility in province A generates 50 per cent of its electricity by hydro, any exports of electricity are assumed to be 50 per cent generated by hydro. Thus, rent per kilowatt-hour of energy exported is assumed to be 50 per cent of the rent per kilowatt-hour for hydro-electricity.

In order to derive estimates based on the approach taken, several factors must be taken into account. First, we must derive some estimate of the rent per kilowatt-hour of salable hydro-electricity generated by utilities in the other provinces.[1] For simplicity, we have derived approximate estimates based on those developed for the four provinces. (As noted in the introduction, the utilities in the remaining six provinces accounted for only about 7 per cent of the total hydro-electricity produced by all utilities in Canada in 1979.)

A second important factor is that exports of electricity to the United States are quite substantial, and most of the rent on hydro-electric exports is not collected from U.S. consumers.[2] Thus, some of the hydro rent in Canada is lost to U.S. consumers, and this must be taken into account in determining the hydro rent distributed to domestic users.

A third factor that must be taken into account is the interprovincial transfers of electricity. To take New Brunswick as an example, that province imports a significant quantity of electricity from Quebec. Thus, on average, any demand for electricity in New Brunswick or for exports from New Brunswick to the United States would be met partially from power generated in Quebec. Most of the electricity produced in Quebec is generated from hydro, so that some of the rent gained by New Brunswick consumers or by U.S. users of electricity imported directly from New Brunswick would originate in Quebec.

Direct transfers alone, however, are not sufficient to identify the ultimate source of hydro rent received by users. Continuing with the example above, some of the electricity supplied to Quebec originates at Churchill Falls, so that ultimately some of the rent received by consumers in New Brunswick (or by U.S. consumers of exports from New Brunswick) would originate at Churchill Falls. As a second example of indirect effects, some of the power sold by utilities in Quebec is purchased from industrial establishments in Quebec, which, in turn, purchase electricity from hydro in Quebec.

The analysis required to determine ultimate sources of hydro rent, given the pattern of transfers between provinces and between utilities and industrial establishments, may appear at first to be a trivial exercise, requiring a fairly straightforward application of either an input-output analysis or a simple Markov process. But this in fact is not the case. A heuristic, iterative procedure was developed to solve the problem. A description of this procedure is available under separate cover (see Appendix).[3]

The Distribution of Hydro Rent

Table 5-1 presents estimates for 1979 of the distribution of hydro rent from electric utilities by province to users by province or the United States.

Based on our analysis, the rent on hydro-electricity generated by provincial electric utilities was about $4.4 billion in 1979, of which nearly $500 million was lost on exports to U.S. users.

The estimates indicate that Newfoundland lost about $597 million in hydro rents ($543 million to other provinces and $54 million to the United States), while Manitoba lost about $193 million ($124 million on exports and $69 million to other provinces). The major net gainers from other provinces were Quebec ($420 million) and Ontario ($125 million).

Table 5-1

Net Distribution of Hydro-Electric Rent, 1979

	Newfoundland	Prince Edward Island	Nova Scotia	New Brunswick	Quebec	Ontario	Manitoba	Saskatchewan	Alberta	British Columbia	Total
					(Millions of current dollars)						
Rent on production	711.3*	-	26.1	69.2	1,329.1*	763.2	521.8	64.2	42.2	864.5	4,391.5
Rent lost on exports to the United States	-54.4*	-	-0.2	-23.2	-121.4*	-88.6	-123.5	-0.4	-0.1	-76.0	-487.9
Rent distributed to Canadian users	656.9	-	25.9	46.0	1,207.7	674.6	398.3	63.8	42.1	788.5	3,903.6
Rent received by users on the basis of consumption	114.4	3.8	30.8	78.6	1,627.4	799.3	328.8	80.0	44.0	786.6	3,903.6
Net distribution to (-)/from (+) other provinces	-542.5	3.8	4.9	32.6	419.7	124.7	-69.5	26.2	1.9	-1.9	0.0
					(Thousands)						
Population	563.5	122.0	841.8	691.9	6,338.9	8,501.3	1,028.0	951.3	2,052.8	2,589.4	23,680.9
					(Dollars per capita)						
Rent on production	1,262*	-	31	100	210*	90	508	67	21	334	185
Rent lost on exports to the United States	-97*	-	-	-34	-19*	-10	-120	-	-	-29	-21
Rent distributed to Canadian users	1,166	-	31	66	191	79	387	67	21	305	165
Rent received by users on the basis of consumption	203	31	37	114	257	94	320	95	21	304	165
Net distribution to (-)/from (+) other provinces†	-963	31	6	47	66	15	-68	28	1	-1	0

*Churchill Falls is combined with Newfoundland.
†Detail may not add to totals because of rounding.
SOURCE Appendix Table D-8 and Statistics Canada, *Estimates of Population for Canada and the Provinces*, Statistics Canada cat. no. 91-201, 1983, Table 8.

We estimate that, on the basis of production, hydro rent per capita averaged about $185 for the ten provinces. Newfoundland with about $1,262, Manitoba with $508, British Columbia with $334, and Quebec with $210 were the provinces with above-average hydro rent per capita.

Redistribution resulted in a major loss to other provinces of about $963 per capita for Newfoundland and a comparatively minor loss of $68 per capita for Manitoba. Quebec with $66 and New Brunswick with $47 were the largest gainers per capita. As a result, rent gained by users varied from $21 per capita in Alberta to $320 per capita in Manitoba. British Columbia with $304, Quebec with $257, and Newfoundland with $203 were the other provinces with rent above the Canadian average of $165 per capita on the basis of consumption.

6 Summary and Conclusions

The large increase in the world price of oil in recent years has resulted in an increase in the value of the nation's hydro resources used to produce electricity. The objective of this paper was to develop an estimate of the annual (flow of) hydro rent in Canada for 1979. Estimates were derived in detail on the basis of production for the public and private electric utilities in four major hydro provinces – Quebec (including the purchases of hydro-electricity from Churchill Falls), Ontario, Manitoba, and British Columbia – which accounted for about 93 per cent of hydro production by utilities that year.

In this study, hydro-electric rent is measured as the annual flow of saving in economic costs made possible by the use of hydro resources, compared with the least cost, alternative method of generation. Given the technologies available, the least cost, alternative method consists, for the most part, of thermal generating technologies, such as nuclear and coal or other fossil fuels. Empirically, the approach taken was to compute the difference between the annual economic cost of a hypothetical, least cost, all-thermal system and the annual economic cost of the current hydro-thermal system in order to derive an estimate of the hydro rent.

Because the economic cost of the current system is likely to overestimate the least possible economic cost of a hydro-thermal system, due to its inefficiencies and excess capacity, our estimates of economic rent on hydro production are apt to be biased downward.

The estimation of the economic cost of the two systems involved a number of significant adjustments in utility financial accounts, including:

- moving to a measure of the replacement cost from the historical cost of fixed capital;
- using a social opportunity cost of capital and depreciation applied to replacement costs; and
- adjusting transmission costs and line losses downward under the hypothetical all-thermal system.

The estimates derived for hydro rent for 1979 on a production basis were as follows: Quebec with hydro rent of $1.87 billion (of which $0.58 billion is accounted for by purchases from Churchill Falls), Ontario with $0.75 billion, Manitoba with $0.52 billion, British Columbia with $0.82 billion, for a total of $3.96 billion.

The theory of equalization developed by Boadway and Flatters (1982) suggests that hydro rent passed on to users in the form of low prices constitutes a fiscal benefit arising from provincial government activity, which should be subject to equalization. Estimates of hydro rent by province on the basis of consumption as measures of these fiscal benefits are thus derived, taking into account interprovincial sales and the loss of about $0.5 billion in hydro rent through exports to the United States. The estimates thus derived for the provincial distribution of hydro rent on the basis of consumption vary from over $300 per capita in Manitoba and British Columbia, about $250 per capita in Quebec, about $200 per capita in Newfoundland, about $100 per capita in New Brunswick, Ontario, and Saskatchewan, to under $50 per capita in Nova Scotia, Prince Edward Island, and Alberta.

List of Supplementary Tables and Description Procedure

A complete set of these tables and technical description is available without charge upon request from the Communications Division, Economic Council of Canada, P. O. Box 527, Ottawa, Ontario, K1P 5V6.

A Supplementary Tables for Chapter 3

A-1 Economic Prices of Fuels and Variable Operating Costs, 1979-80
A-2 Costs of Generating Capacity and Fixed Operating Costs, 1979 Prices
A-3 Generation Mix for Alternative All-Thermal Generating Systems, 1979

B Supplementary Tables for Chapter 4

B-1 Economic Cost of Current System: Electric Utilities, 1979
B-2 Estimated Economic Cost of Energy Purchased by Quebec from Churchill Falls (at the Border), 1979
B-3 Estimated Replacement Value of Net Fixed Capital for Churchill Falls, in Current Dollars, 1979
B-4 Economic Cost of All-Thermal Systems, Electric Utilities, 1979
B-5 Supplementary Estimates for Deriving Economic Costs of All-Thermal Systems, 1979
B-6 Estimated Economic Rent on Electricity Purchased by Quebec from Churchill Falls

C Description of the Procedure to Estimate the Provincial Distribution of the Rent on Hydro-Electricity Generated by Electric Utilities on the Basis of Consumption

D Accompanying Tables

D-1 Source Matrix (S)
D-2 Production Matrix (P)
D-3 Diagonal Elements of Diagonal Matrix of Domestic Final Demands (D)
D-4 Column Vector of Exports (E)
D-5 Diagonal Elements of Diagonal Matrix of Rent per Kilowatt-Hour of Salable Hydro (R)
D-6 Ultimate Flows Matrix (U)
D-7 Comparison of Estimated Salable Hydro and Actual Salable Hydro Generated by Provincial Utilities, 1979
D-8 Estimated Transfers of Hydro Rent, from Electric Utilities to Users in Canada and in the United States, by Province, 1979

Notes

INTRODUCTION

1 Economic Council of Canada, *Financing Confederation: Today and Tomorrow* (Ottawa: Supply and Services Canada, 1982).

2 R. Boadway and F. Flatters, *Equalization in a Federal State: An Economic Analysis*, Economic Council of Canada (Ottawa: Supply and Services Canada, 1982).

3 With the recognition of provincial property rights to natural resources, however, equity would require equalizing only a fraction of such revenues: that fraction would be the average marginal federal personal income tax rate that would apply were such revenues considered to be current income of provincial residents.

CHAPTER 1

1 In fact, this very high ratio for Prince Edward Island is somewhat misleading. The reason is that the total amount of energy lost and unaccounted for has been subtracted from provincial generation to calculate net production. If instead, the amount of energy lost and unaccounted for is prorated between electricity generated within the province and that imported, then the amount of net production increases and the ratio of consumption to net production falls to 3.4. There is much less distortion as a result of reducing production for the full amount of energy lost and unaccounted for to derive net production for the other provinces, where provincial generation constitutes a much higher proportion of total supply.

2 The economic rent obtained from a resource also depends on the cost of transportation to market. The greater the transport cost, other factors unchanged, the lower the economic rent.

3 The operating and capital cost of marginal economic infrastructure required to exploit the resource should also be included in the cost of production.

4 If there are actual or potential substitutes for the resource, then changes in technology in the production of these substitutes would also result in changes in the economic rent on the resource by shifting the demand curve and thus changing the competitive market price.

5 Economic rent can accrue to labour and capital as well as to "land" for a variety of reasons, such as market imperfections resulting from monopoly or oligopoly, tariffs, shortages arising from supply adjustment delays, and rare human skills. Such rent is generally assumed to be temporary in nature (although this may not be so in the case for tariffs and rare human skills) and is referred to as "quasi-economic rent."

6 J.-T. Bernard, G. E. Bridges, and A. Scott, "An Evaluation of Potential Canadian Hydro Electric Rents," Department of Economics Resource Paper 78, University of British Columbia, Vancouver, February 1982.

7 It is important to note that underlying any set of demands is a price or set of prices. This point will be referred to later in the discussion.

8 Utilities in Canada generally plan the expansion and operation of the system with only the demands of domestic customers in mind. Exports are seldom planned for or made on a guaranteed basis; rather they are made in off-peak periods on an if-available basis as a means of increasing the utilization rate of generating facilities. As long as the revenues received exceed the variable cost of production and can thus make some contribution to fixed cost, off-peak exports are cost-effective.

CHAPTER 2

1 D. Anderson, "Models for Determining Least Cost Investments in Electricity Supply," *The Bell Journal of Economics and Management Science* 3 (1972):267-301.

2 The capacity and energy from hydro sites with similar characteristics, that is, ratios of energy available to the energy that would be available at full capacity, can be aggregated for the purpose of locating hydro generation under the load curve. Thus one could consider that capacity D_C is an aggregation of all baseload hydro capacity and that $D_A - D_B$ is the sum of all energy limited capacity with similar operating characteristics.

Because of seasonal variations in energy availability, production scheduling with hydro is usually done on a monthly basis. For example, a seasonal hydro site may be operable at or near full capacity in certain months – say, spring – and not operable at all during other months – say, winter. Thus, in the spring months, seasonal hydro can be aggregated with baseload hydro for purposes of production planning. In this case, the allocation of production would be done using monthly load duration curves using the same general principles as those presented in the text.

3 Equivalently, we could derive the capacities of the various thermal technologies required in the integrated system using a slightly different procedure. A thermal load duration curve – that is, net of that supplied by hydro – would be derived by subtracting, for each hour along the time axis in Figure 2-3, the demand met by hydro from the demand on the load duration curve. This thermal load duration curve, when placed above the thermal cost curve, would yield the same solution

for capacity and energy required for the various thermal technologies as that shown in Figure 2-3.

4 See the discussion on the social discount rate for Canada in the papers by: D. F. Burgess, "The Social Discount Rate for Canada: Theory and Empirical Evidence," *Canadian Public Policy* 7(1981):383-94; and G. P. Jenkins, "The Public Sector Discount Rate for Canada: Some Further Observations," *Canadian Public Policy* 7(1981):399-407.

CHAPTER 3

1 It must be determined whether the additional costs associated with retiring a plant earlier than its planned economic life are greater or less than the incremental costs that would have been incurred by operating a substitute plant that does not become obsolete prematurely. If the costs of operating an alternative plant are greater, then the initial plant should be maintained in the expansion plan with its annual capital costs adjusted upward to reflect its shorter economic life. However, these additional costs can be somewhat reduced if the candidate for retirement can still be used to meet reserve requirements.

On the other hand, if the saving in the operating cost of the plant that becomes obsolete (in its early years of operation) is not as large as the additional capital costs incurred (because of its shorter life) then simulations of the total system costs must be carried out with substitute plants to determine the set of generating plants that will yield the lowest present value of total generating costs over time.

CHAPTER 4

1 The impact of changing electricity prices on the load shape and quantity of electricity demanded was determined through the use of DSP – a Demand Simulation Program for forecasting load growth developed by Econonalysis Incorporated – available through Cybernet Services of Control Data Corporation.

CHAPTER 5

1 We do not include in this analysis the rent on hydroelectricity generated by industrial establishments, although we do include the rent on hydro sold by utilities to these industrial establishments.

2 For example, the average annual price per kilowatt-hour of electricity received by Quebec for exports in 1979 was 14.4 mills, which does not even cover our estimated average economic cost of 26.2 mills per kilowatt-hour. Similarly, average revenue per kilowatt-hour for British Columbia was 22.5 mills, compared with an estimated average economic cost of 48.4 mills per kilowatt-hour.

For the analysis associated with Chapter 4 (see Appendix Table B-1, lines 12 and 13), we have used an opportunity cost of 111.2 mills per kilowatt-hour for diesel and light fuel oil and 62.6 mills per kilowatt-hour for natural gas. These would approximate the opportunity cost of fuels used during peak periods by electric utilities in the United States that purchase these exports. A straight average of these two figures is about 86 mills per kilowatt-hour. This estimated opportunity cost is for fuel only, and does not include other operating and maintenance costs and, more significantly, capacity costs for the importing utility. If the marginal cost of hydro during these periods is taken to be zero, this back-of-the-envelope calculation suggests that Hydro-Quebec received only about one-sixth of a minimum estimate of the potential economic rent on these exports. In our analysis, we assume that all of the hydro rent on exports to U.S. consumers is lost.

3 An exact mathematical solution was provided by Dr. David Binder at Statistics Canada, but its application would have required much greater time and cost than the procedure employed.

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