

Managing Instead of Building: B.C. Hydro's Role in the 1990s*

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1. Introduction

In the three decades since the nationalization of the B.C. Electric Company in 1962, the production, transmission and distribution of electricity¹ in British Columbia has been almost exclusively the responsibility of the Crown corporation, B.C. Hydro and Power Authority (B.C. Hydro). In production, B.C. Hydro accounted for 42,000 of the 61,000 GWh of electricity produced in 1988 in the province.² Notable exceptions were Alcan, producing over 4,700 GWh for its aluminum refinery and for the community of Kitimat; West Kootenay Power and Light (WKPL), producing about 5,000 GWh for the Cominco smelter in Trail and several communities in the southeast of the province; and the approximately 2,500 GWh internally *cogenerated*³ and consumed by pulp and paper mills throughout the province. There are also several small operations which, although negligible on a provincial scale, play a significant role in non-integrated localities.⁴ In transmission, B.C. Hydro owns and operates essentially all the major transmission lines in the province. The only exceptions are lines in the areas serviced by Alcan and WKPL. B.C. Hydro has also dominated

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¹ In this paper the terms *electricity* and *power* are used synonymously. This is also the case for the terms *private producer*, *independent producer*, *qualifying facility*, and *non-utility generator*. The latter four are not perfect synonyms, but where a particular nuance is important it will be clarified in the text.

² This total includes electricity produced and consumed within the same private establishment, for example, the electricity that a pulp mill produces for its own consumption.

³ Cogeneration refers to the combined production of electricity and steam. For example, a hospital which burns natural gas to produce steam for space heat could first send the steam through a turbine and generate electricity. Or a paper mill that uses steam for drying paper could cogenerate electricity and steam. In comparison to conventional thermal electricity production, cogeneration increases the efficiency of energy use from the 30 to 40 percent range to the 75 to 85 percent range.

⁴ Two examples are Queen Charlotte Power Corporation at Sandspit on the Queen Charlotte Islands and Robson Valley Power Corporation at McBride.

the distribution of electricity. The exceptions include the areas serviced by Alcan and WKPL, as well as municipally owned utilities in six small and medium size communities. With more than 1.2 million direct customers, B.C. Hydro serves over 92 per cent of the province's population.

The predominant role of a single Crown utility in the B.C. electricity market is consistent with the Canadian norm. Electricity markets in six of the other nine Canadian provinces are dominated by single Crown monopolies. While the historical events leading to this prevailing market structure vary considerably from one province to another, it is primarily the product of two common factors: (1) the natural monopoly character of electricity markets and (2) the important role expected of large electricity projects in Canadian economic development.

One consequence of these two factors has been the perception that electric utilities in Canada functioned primarily as large construction companies, with a high percentage of employees and management owing their positions to expertise in building electricity generating plants. At times, this perception has been a cause of suspicion, critics arguing that provincial utilities have been so eager to construct electricity megaprojects that they fail to seriously consider alternatives, such as conservation, co-ordination and non-utility, smaller-scale electricity supply sources. However, this situation appears to be changing. This change is especially notable in British Columbia, where in just a few years B.C. Hydro has evolved from an electricity production monopoly, with resource plans for intensive hydro development of most of the province's river basins, to a management corporation which seeks to investigate carefully every alternative option for meeting the province's electricity service needs.

This paper explores the history and causal factors of this development. Its key argument is that much can be explained by trends that are common to electric utilities throughout industrialized countries. Because these trends originated primarily in the U.S., the paper contains a review of major developments in that country's electric utility industry during the 1980s. Stricter environmental controls, along with economic and technical factors, have led utility resource planners to rethink their assumptions about economies of scale in electricity production. These planners have also begun to recognize that the cheapest resource of all is conservation, if households and firms can be induced to make the necessary investments. These changes in planning practices have coincided with regulatory and political developments. Rising electricity prices mobilized public interest groups to pressure regulatory agencies to more closely scrutinize utility resource planning practices. At the same time, an ideological shift in U.S. federal politics

led to initiatives to deregulate various domestic markets, one of these being electricity production.

The evidence suggests that politicians, utility regulators and utility managers in Canada have followed the developments in the U.S., albeit with some delay. Utilities in Canada are increasingly more willing to review carefully the full range of electricity supply and demand options. Since 1987, B.C. Hydro has been at the forefront of this movement among utilities in Canada, but its innovations are not unique in comparison to that which has already occurred in the U.S.

This trend away from megaproject development toward a more comprehensive approach to electricity system management is likely to be even more pronounced in B.C. than in many other jurisdictions; the province is endowed with an especially rich portfolio of alternative electricity resource options. Thus, under the most likely set of demand and supply scenarios, B.C. Hydro will not need to complete another major hydroelectric project within the next 15 years. This implies that the corporation will continue to evolve in the 1990s towards a role in which it functions almost exclusively as an electricity management company, coordinating investment decisions, operating practices and electricity transfers of a diverse array of consumers and independent producers.

This paper is divided into six sections. Section 2 presents the economy of scale and economic development rationales for monopoly electric utilities in Canada. Section 3 explores the origins of the dramatic changes in the US electric utility industry in the 1980s. The British Columbia manifestations of these changes are detailed in Section 4. Section 5 surveys the implications and challenges presented by this new situation for the management and regulation of B.C.'s electricity system, especially for the role of B.C. Hydro over the next decade. Section 6 contains the Conclusion.

2. *North American Electricity Market Trends and Specific Developments in B.C. over the Last Three Decades*

2.1 Production Economies of Scale and High Fixed Costs of Transmission and Distribution

From the Second World War to the late 1970s, most energy economists would have referred to all three sectors of the electricity market as exhibiting the classic characteristics of *natural monopoly*, a market in which society is better off with control by only one firm. A natural monopoly market is characterized by *high fixed costs of production* — usually due to capital intensive distribution systems — and *economies of scale*. In addition

to electricity markets, natural monopoly is associated with railways, natural gas transmission and distribution, telephone, and other communication services.

Economies of scale in electricity production imply that one firm, with one large production unit, would have lower production costs than two firms with units of half that size. If the single firm, a monopoly, is constrained to set price equal to cost, including a normal return to capital invested, the cost to society is lower than under two firms.

It is therefore in society's interest to favour monopoly in natural monopoly markets, provided that the firm is constrained by government or its agencies to set price equal to cost. Government intervention may take the form of a public utility commission, charged with regulating the pricing and investment behaviour of natural monopoly firms; this has been the usual approach in the U.S. Government intervention may also take the form of a publicly owned monopoly; this has been the usual approach in Canada.

Another factor contributing to natural monopoly is the high infrastructure cost of transmitting and distributing certain products, such as electricity and natural gas. The retail price of these products would be dramatically higher if competitors were to build parallel transmission and distribution networks to service and compete for the same customers.

Again, the socially optimal solution is to countenance monopoly, be it private and publicly regulated as in the U.S., or publicly owned as in Canada. Moreover, the symbiosis of managerial, market, and technical skills between electricity production, on the one hand, and electricity transmission and distribution, on the other, has favoured the existence of single, large, vertically integrated electric utilities vested with control of all three sectors of the electricity supply market.

Electricity is produced from several energy sources, the predominant ones being nuclear, hydro, and the three fossil fuels: coal, oil and natural gas. During the postwar evolution of electricity production capacity, each of these sources has exhibited, or has been believed to exhibit, economies of scale as larger plants have been designed and brought into production.⁵ However, a hindsight evaluation shows that many of the assumed scale advantages of electricity generation were more apparent than real.

There is little disagreement that the larger fossil fuel plants built in the 1960s realized economies of scale relative to the smaller plants of the early 1950s. Evidence from coal plants in the U.S. shows that these economies

⁵ See for example K. M. MacRae, *Critical Issues in Electric Power Planning in the 1990s* (Calgary: Canadian Energy Research Institute, 1989), 33.

were due primarily to construction cost savings (cost per KW of installed capacity), but also to the improved thermal efficiencies (i.e. leading to lower unit operating costs) of large units of higher pressure and temperature.⁶

As a more recently developed electricity source, nuclear energy lacks clear historical evidence of economies of scale. Nonetheless, *ex ante* engineering estimates of size-related construction cost reductions led to the planning and construction of larger and larger units during the 1960s and 1970s.

Economies of scale were also assumed to exist with hydro electricity generation, again due to reduced construction costs per KW of installed capacity with larger projects. However, high quality hydroelectric sites (in terms of unit production cost and favourable location) are a limited resource; consequently, the sequential exploitation of hydroelectric sites tends to be associated with rising costs of both construction and transmission. This scarcity-related time trend should not be confused with the economies of scale question. For example, the massive projects on the Peace and Columbia rivers in the 1960s produced electricity at an average levelized cost of 1.67 cents/KWh compared to the average of 1.43 cents/KWh of the smaller hydro facilities that comprised the balance of the existing B.C. Hydro generating system.⁷ But at the time of their development, these large projects were estimated to be cost-effective relative to smaller-scale hydro alternatives.

2.2 Hydroelectricity and Economic Development in B.C.

Large hydroelectricity projects have several attributes that make them attractive instruments of economic development. First, project construction provides a dramatic macroeconomic stimulation. Second, a ready supply of inexpensive electricity, perhaps due to economies of scale but often also

⁶ P. Joskow, "Productivity Growth and Technical Change in the Generation of Electricity," *The Energy Journal*, 8:1 (1987): 17-38.

⁷ All monetary values are in 1989 Canadian dollars; costs were converted using the Statistics Canada Industrial Price Index. Historic costs of hydroelectric projects are calculated from three sources: J. T. Bernard, G. E. Bridges and A. Scott, "An Evaluation of Potential Canadian Hydro Electric Rents" (Vancouver: University of B.C., Department of Economics, 1982), Resources Paper no. 78, Statistical Appendix. B.C. Hydro, *Annual Report*, (Vancouver: B.C. Hydro, 1962-1981). Canada, Energy, Mines and Resources, *Electric Power in Canada*, (Ottawa: Energy, Mines and Resources, 1978-1981). The construction and operating cost of major dams in the 1960s (the Shrum, Mica and Seven Mile) were separated from the costs of all previously built dams in the B.C. Hydro system. For details of the calculations contact the authors.

due to public subsidy,⁸ can play an important role in economic development, especially by attracting industry. Third, hydro projects may include additional development benefits by providing irrigation, drinking water, flood control, roads, recreation areas, and improved navigation.

During the depression of the 1930s, the Roosevelt government in the U.S. turned to large hydroelectricity projects to stimulate economic development in two regions, the Appalachians and the Pacific Northwest. Public corporations, the Tennessee Valley Authority and the Bonneville Power Administration, were established to concentrate the capital and expertise necessary to co-ordinate these massive undertakings.

In British Columbia, the creation of B.C. Hydro has certain parallels with this earlier U.S. experience. W. A. C. Bennett's Social Credit government of the late 1950s sought to promote resource development in the province's hinterland by harnessing the hydro power of two major river systems, the Peace and the Columbia.⁹ Private electricity firms were unwilling to undertake the massive investment on the Peace River, so Bennett nationalized B.C. Electric in 1962, creating B.C. Hydro. At the same time he negotiated the Columbia River Treaty in which dams on the Columbia in B.C. would be paid for by the U.S. in exchange for downstream benefits.¹⁰ Power from the Peace was sold domestically, contributing through plentiful supply at low industrial prices to the dramatic development of the pulp and paper industry in the interior of the province in the 1960s.¹¹

The role of B.C. Hydro's hydroelectric projects as macroeconomic stimuli was an implicit, but never publicly stated, policy of the government of B.C. One reason is that although major hydroelectric projects can combine several desirable objectives, they can also be controversial. Valley bottoms are a finite resource, and B.C. Hydro's long-term plans, which encompassed every major river system in the province, were seen as threatening to many interest groups. Depending on the project, these could include the commercial fishery, foresters, native people, farmers, and

⁸ For example, Crown electric utilities in Canada have access to low-cost debt capital through government-backed loans and are exempt from federal income taxes. Moreover, the money invested by provincial governments to acquire utilities has rarely provided dividends or other investment returns and certainly not at levels that could be described as normal returns to equity capital.

⁹ J. T. Bernard and R. Payne, "Natural Resource Rents and Hydroelectric Power: the Case of British Columbia and Manitoba," in T. Gunton and J. Richards (eds.), *Resource Rents and Public Policy in Western Canada*, (Halifax: Institute for Research on Public Policy, 1987), 63.

¹⁰ Downstream benefits are the additional KWh that can be generated at hydroelectric facilities downstream (in the U.S.) thanks to the co-ordinated water retention and control provided by upstream facilities (in Canada).

¹¹ J. T. Bernard and R. Payne, op. cit., 78.

organizations concerned with wilderness recreation, protection of wildlife habitat, and wilderness preservation. Therefore, while the government has been willing to defend B.C. Hydro's mandate "to support the economic growth of British Columbia through the efficient supply of electricity,"¹² it has been unwilling to pay the political costs of promoting hydroelectric development aimed solely at the export market; projects have always been submitted on the grounds that they would soon be required to meet domestic demand.

Short-term export of electricity did occur, largely because of B.C. Hydro's preference to err on the side of overestimating demand growth, rather than risk supply shortages.¹³ However, the riskiness of premature construction became a concern to B.C. Hydro management with the Revelstoke Dam. At its completion in 1984, the dam was totally surplus to domestic needs, coinciding with a recession in western economies that led to stagnant domestic demand and weak export markets. From 1984 to 1988 a substantial quantity of this surplus electricity was exported on spot markets at an average price of 2.4 cents/KWh,¹⁴ while the levelized cost of electricity from the dam is in the order of 4.2 cents/KWh.¹⁵

The controversy surrounding the Revelstoke Dam, especially concerning its environmental impact and its need (i.e., the credibility of B.C. Hydro's domestic demand forecasts), contributed to the decision by the provincial government in 1980 to overhaul the provincial process of evaluating and regulating energy projects.¹⁶ This included the creation of the British Columbia Utilities Commission (BCUC) and a formal energy project review process for major projects.¹⁷

This new agency and the new process were quickly tested by another B.C. Hydro dam proposal, Site C on the Peace River. Although, after a year of hearings, the BCUC approved the project as environmentally acceptable, it also recommended delay until B.C. Hydro's forecasting

¹² B.C. Hydro, *Annual Report* (1989), op. cit.

¹³ Between the early 1970s and the early 1980s B.C. Hydro's capacity surplus increased from about 20 to 60 per cent of its total system. J. T. Bernard and R. Payne, op. cit., 78. Even without overestimated demand growth, there would still be some surplus electricity available for export from B.C. Hydro's hydro-based system because of the annual variation in water flows.

¹⁴ B.C. Hydro, *Twenty-Year Resource Plan*, (Vancouver: B.C. Hydro, 1989), 15.

¹⁵ Communication with B.C. Hydro, Policy Development Department, 1991.

¹⁶ M. Jaccard, "An Evaluation of the Regulatory Regime for Electrical Energy in British Columbia," (unpublished M.R.M. thesis, School of Resource and Environmental Management, Simon Fraser University, 1984).

¹⁷ N. Banks, "Energy Project Review in British Columbia: a Comment on the Utilities Commission Act, 1980," *UBC Law Review* 16:1 (1982).

methods provided firmer evidence of the dam's need.¹⁸ The delays brought on by the regulatory process, and the cabinet's indecision once the report was tabled, provided enough time for the full magnitude of the recession of the early 1980s to manifest itself, and the dam was postponed indefinitely.

The 1980s have been the decade of the Site C guessing game. B.C. Hydro has maintained the dam's status as its next major project, but domestic demand has not justified commencement.

Several times the provincial cabinet has hinted that economic development motives would lead to construction in advance of domestic requirement. However, negotiations for adequate transmission access through the U.S. Pacific Northwest to export markets in California have not succeeded. Furthermore, at a time of growing environmental sensitivity, and when interest groups have considerable expertise in influencing public opinion, there are now significant political risks to the policy of using hydroelectric projects to further economic development goals. We return to this issue in Section 4.

3. *Economic and Regulatory Changes in the U.S. Electricity Industry*

During the 1980s the electric utility industry in the U.S. underwent profound changes. While the causes of these changes were often particular to the U.S., the effects on industry practice have spread to many other OECD countries. To understand developments in Canada, it is therefore necessary to first trace economic and regulatory changes in the U.S. electricity industry.

3.1 Crisis in the Electric Utility Industry

Between 1978 and 1986, electricity markets in western countries experienced a period in which demand growth deviated from its stable path of previous decades. This was primarily caused by erratic international oil prices, which led to sharp increases in the cost of producing electricity from fossil fuels. But there were also factors affecting the costs of other sources of electricity. In the U.S., nuclear power, which had been acclaimed in the 1960s as the successor to fossil fuels for electricity generation, gradually lost public and financial support as reliability problems, accidents, and more stringent licensing requirements led to cost overruns and an increased perception of riskiness.¹⁹ Also in the U.S., the few remaining large hydro

¹⁸ B.C. Utilities Commission, *Site C Report*, (Vancouver: BCUC, 1983).

¹⁹ M. Kaku and J. Trainor (eds.), *Nuclear Power: Both Sides — The Best Arguments For and Against the Most Controversial Technology* (New York: M. W. Norton and Company, 1982).

sites faced increased resistance to development from vocal, well-organized interest groups.

These factors led to extraordinary increases in the price of electricity in most areas of North America in the late 1970s and early 1980s. Moreover, these price increases coincided with an economic downturn in the early 1980s, so that, partly due to price response and partly due to economic recession, growth in electricity demand slowed dramatically, becoming negative in some regions. This occurred just when many utilities were committed to substantial capacity expansion. As a consequence, several utilities in the U.S. were forced to abandon incomplete projects, often with extreme financial consequences.²⁰

The dramatic increases in the cost of electricity from conventional sources, and the perception that this rising cost trend would continue into the indefinite future, contributed to skepticism about the continued existence of economies of scale conditions in the generation sector of the electricity industry. Recent analysis of data from this period bears out this skepticism.

Research by Joskow indicates that thermal coal units larger than 550 MW exhibited diseconomies of scale in the period 1970 to 1982.²¹ Units larger than this threshold have not achieved anticipated thermal efficiency gains. Moreover, Joskow found that these plants have been very costly to construct because of regulatory changes and very costly to operate because of reliability problems.

The larger nuclear plants of the late 1970s and 1980s were also found to be much more costly to construct and operate than estimated, partly because of changing safety regulations and partly because of unexpected reliability problems. Kaku and Traines cite evidence that nuclear plants completed in the early 1980s tended to cost about three times more than had been estimated when the plants were initially designed and approved.²² For example, Ontario Hydro experienced construction cost overruns of 252 per cent, 265 per cent, and 431 per cent respectively, with its nuclear plants Pickering B, Bruce B, and Darlington.²³

The development of hydro sites throughout North America has generally followed a sequence from the best and cheapest sites to the more expensive. For example, one of B.C. Hydro's lowest-cost prospective hydroelectric

²⁰ M. Jaccard, "Les Compagnies Electriques aux Etats-Unis: Nouvelles Contraintes et Stratégies," *Energie Internationale: 1988-1989*, (Paris: Economica, 1988), 155-68.

²¹ P. Joskow, op. cit.

²² M. Kaku and J. Traines, op. cit.

²³ D. Poch, *Energy Probe's Statistical Handbook: The Other Energy Pie* (Toronto: Energy Probe Research Foundation, 1985).

projects, Site C, will produce electricity at about 5 cents/KWh, a considerable increase from the unit costs of the megaprojects of the 1960s.²⁴

Several factors contributed to this change in the economics of electricity production. First, growing public resistance to energy megaprojects has increased regulatory requirements and delayed completion, ultimately leading to higher construction costs. Second, the long lead times of large projects entails substantial uncertainty and risk both for financing (interest rate fluctuation) and system planning (demand fluctuation), particularly in a period of volatile energy markets. Third, for a diversity of reasons, large thermal units in the 1980s have experienced increased down time for maintenance and repair. Fourth, most of the lowest-cost large hydro sites have already been exploited.

3.2 Government Response: PURPA in the U.S.

The energy crisis mentality of the late 1970s produced an array of responses from governments. The U.S. government was particularly concerned with dependence on imported oil and rising oil prices, and it therefore fostered policies to (1) encourage conservation, (2) increase the reliance on indigenous coal, and (3) develop various alternative energy sources that had formerly been considered uneconomic: cogeneration, wind, solar, biomass, small hydro, and municipal waste.

Concern was also expressed for the institutional barriers to such policies inherent in the monopoly integration of all three sectors of the electric utility industry. Because it controls the transmission and distribution system, an electric utility is a monopsonistic purchaser of electricity.²⁵ If, as is usually the case, the utility is also a producer of electricity, there is no incentive for it to seriously consider supply offers from independent electricity producers.

This explains the rationale behind the Public Utility Regulatory Policy Act (PURPA) of the U.S. government in 1978.²⁶ Sections 201 and 210 of PURPA are key in that they specify remedies for the economic, regulatory, and institutional barriers to cogeneration and small power production facilities. Section 201 establishes eligibility criteria for *qualifying facilities*

²⁴ B.C. Hydro, *Value of Electricity* (Vancouver: B.C. Hydro, 1989). However, comparison is partly distorted by the negligible incorporation of costs for environmental compensation and mitigation in the earlier projects.

²⁵ In a monopsony market there is only one potential buyer, with obvious market power.

²⁶ For a detailed analysis see, E. Kahn, *Electric Utility Planning and Regulation* (Washington D.C.: American Council for an Energy-Efficient Economy, 1988).

(QFs). QFs are not subject to *rate-of-return regulation*.²⁷ Utility ownership of QFs cannot exceed 50 per cent. Cogeneration units can be of any size, although they originally could not consume oil.²⁸ Non-cogenerating, small power producers cannot exceed 80 MW in size and must base at least 75 per cent of their energy inputs on biomass, waste, solar, wind or geothermal.²⁹ Section 210 authorizes the Federal Energy Regulatory Commission (FERC) to issue regulations specifying the rules governing the sale of electricity by QFs to utilities. The key regulation of Section 210 stipulates that a utility must purchase electricity from QFs at a price equivalent to the utility's *avoided cost*, which was originally interpreted as the cost per KWh of electricity or the cost per KW of capacity (depending on the utility's needs) of the next major project in the utility's system plan.³⁰

The PURPA legislation, and its administration by the FERC and by public utility commissions over the last 12 years, has had a dramatic impact on U.S. electricity markets. The implementation of PURPA provided strong evidence that economies of scale in electricity generation had indeed been surpassed; several utilities were deluged with supply offers from QFs at the avoided cost rates.³¹ Initially, some public utility commissions required utilities to accept these offers from independent producers at rates fixed at the utility's avoided cost, often without provisions for rate adjustment to reflect changing economic conditions. As a consequence, the fall of fossil fuel prices in 1986 resulted in windfall profits for some independent producers.³²

However, as a surplus of QF supply emerged in certain jurisdictions, utilities, and regulators began to reinterpret avoided cost. If the supply offered by QFs exceeds demand (i.e., the utility's estimate of its electricity needs) at the avoided cost, a competitive market has developed. Some QFs

²⁷ In rate-of-return regulation the utility commission regulates product price such that the utility receives a *normal* return on its investment, i.e., a return that is commensurate with the degree of risk and potential returns from comparable investments.

²⁸ The Power Plant and Industrial Fuel Use Act (1978) encouraged replacement of natural gas and oil with coal.

²⁹ M. D. Devine et al., "PURPA 210 Avoided Cost Rates: Economic and Implementation Issues," *Energy Systems and Policy*, 11 (1987): 87.

³⁰ W. R. Meade, "Competitive Bidding and the Regulatory Balancing Act," *Public Utilities Fortnightly*, 17 September 1987, 23.

³¹ "Thus far, the capacity offered by private producers has often been 10-20 times greater than the utility's capacity requirements." E. P. Kahn et al., *Evaluation Methods in Competitive Bidding for Electric Power* (Berkeley, California: Lawrence Berkeley Laboratory, 1989), 2-3.

³² For example California's Standard Offer #4, passed in 1983, required utilities to sign fixed-rate 10 year contracts with qualifying facilities. See M. D. Divine et al., *op. cit.*, 93.

may earn excessive profits if they are paid the avoided cost rate for their electricity. Therefore, when the utility, or its regulators, must choose among alternative supply offers, the low-cost competitor should be chosen, assuming that reliability and other non-cost factors are comparable. Generally, some kind of closed bidding technique, if competitive, can elicit the market price for electricity production from an array of independent prospective producers.³³ The price that emerges from such a bidding process should replace the concept of avoided cost as the yardstick against which various utility investments, including conservation, should be compared.

3.3 Efforts to Deregulate the Electricity Generation Sector

The inauguration of President Reagan in 1980 marked the beginning of a decade in which the U.S. federal government pushed for deregulation throughout the economy. The changing economics of the electricity generation sector has provided a key opportunity for this policy thrust.

Primarily through its agency, the Federal Energy Regulatory Commission, the U.S. government has introduced or is pursuing several policies intended to foster competition in the electricity generation sector.³⁴ First, fuel use restrictions have been eliminated, allowing technologies using any form of energy to compete under the PURPA rules.³⁵ Second, utilities commissions are being encouraged to establish bidding procedures to replace the avoided cost principle of PURPA in determining the price that utilities should pay for independently produced electricity.³⁶ Third, ownership restrictions are being relaxed so that non-QFs (*independent power producers* — IPPs) are eligible to bid on new capacity requirements; the definition of an IPP may eventually be extended to any private firm, including utilities from other jurisdictions and subsidiaries of the utility purchasing the electricity.³⁷ Fourth, barriers to interutility electricity trans-

³³ R. L. Lehr and R. Touslee, "What Are We Bid? Stimulating Electric Generation Resources Through the Auction Method," *Public Utilities Fortnightly*, 12 Nov. 1987, 11-17.

³⁴ D. J. Smith, "FERC Pushes for Deregulation of Power Production," *Power Engineering*, October 1987, 38-40.

³⁵ The sections of the Power Plant and Industrial Fuel Use Act (1978) favouring coal over oil and natural gas were repealed in 1987.

³⁶ Between 1984 and 1989, thirty-three states in the U.S. have adopted or are developing competitive bidding procedures for the procurement of new electricity generating capacity. R. Phillips, "The Future of Competitive Power Generation," *Public Utilities Fortnightly*, 15 March 1990.

³⁷ R. Haman-Guild and J. Pfeffer, "Competitive bidding for new electric power supplies: deregulation or reregulation?" *Public Utilities Fortnightly*, 17 September 1987, 9-20.

fers (wheeling) are being removed so that, if state regulators are favourable, a utility, QF or IPP in one jurisdiction can bid for the additional electricity requirements of a utility in another jurisdiction.³⁸

Utilities in the U.S. have not been particularly averse to these efforts to encourage unregulated independent electricity production. One important reason has been the shift in utility management attitudes about the riskiness of investment. Historically, regulated electric utilities have been observed to overcapitalize because economies of scale and lags in the regulatory process allowed capital to earn a return above its full cost.³⁹ Investment was largely risk-free since the utility regulators allowed utilities to earn a return on all investment.

This changed in the early 1980s, when a dramatic growth in system expansion coincided with economic downturn and declining electricity demand. If the increases in revenues necessary to pay for new plants were not to come from increased sales, higher rates were required. However, under pressure from consumers and politicians, utility commissions in the U.S., for the first time, did not allow all costs to be passed on to consumers in the form of rate increases, thereby resulting in significant losses for some utility investors. This breaking of the *regulatory compact* shifted some of the risks of misinvestment from the consumers to the investors, with a profound impact on the investment attitudes of utility management.

Whereas utility managements in the past tended to favour large projects, they are now at times described as capital averse.⁴⁰ Utility managements have become innovative in their pursuit of small scale opportunities to affect the supply-demand balance without incurring the massive debt load associated with major project investments.⁴¹ In what has been called the *least cost planning* approach, utility managements now increasingly pursue: (1) a multiplicity of demand-side management programs to encourage cost-effective conservation and load shifting, (2) upgrading and better utilization of existing supply capacity, (3) interutility connection and coordination to take advantage of power system complementarities, (4) interruptible contracting and other cost-effective ways of backing up

³⁸ Ibid.

³⁹ Referred to as the Averch-Johnson effect from H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, December 1962.

⁴⁰ E. P. Kahn et al., op. cit., 2-5.

⁴¹ Smaller scale supply sources and conservation also provide the benefit of quick activation. By not requiring a five to ten year lead time, these resources offer flexibility benefits to the system planning process. See E. Hirst, "Flexibility Benefits of Demand-Side Programs in Electric Utility Planning," *The Energy Journal*, 11:1 (1990): 151-63.

the existing generation system, (5) independent power from any non-utility generating source.

Many of these programmes are still in their infancy, yet they clearly indicate the trend toward competition and innovation in electricity generation. And while the trend toward utility deregulation may have initially had ideological overtones, its competitive and small scale flavour is now seen as desirable by all mainstream political perspectives in the U.S. and increasingly Canada. Moreover, the experience in the U.S. provided evidence in support of what many utility critics in other OECD countries had been arguing for some time: (1) that economies of scale in electricity production have been surpassed, and (2) that utility managers should be much more innovative in seeking lower risk, lower cost alternatives to large electricity generation projects.

4. The Changing B.C. Electricity Market in the 1980s and 1990s

4.1 The Transformation of B.C. Hydro in the 1980s

The 1980s saw a dramatic change in the size and functions of B.C. Hydro. In 1979 the company had 12,550 employees in its electricity, natural gas, and railway divisions.⁴² By 1989 the company had been trimmed down to 6,419 employees; the natural gas and railway operations, as well as several smaller units, have been detached or privatized. In the electricity sector of B.C. Hydro, the number of employees decreased from 8,507 in 1982 to 5,187 in 1989, a reduction of 39 per cent in seven years.⁴³

What factors were responsible for this transformation? First, the completion of the Revelstoke dam and the postponement of the Site C dam eliminated the need for most of the employees engaged in project development. Second, in response to the recession of the early 1980s the provincial government adopted a policy of public sector budget reduction, in which B.C. Hydro was included. Third, the new 1986 provincial government of W. Vander Zalm sought to privatize certain government functions and applied this policy to B.C. Hydro's operations.

This trend to downsize and specialize B.C. Hydro has been accompanied by a shift in management philosophy to one which is highly receptive to the innovations in utility management originating in the U.S. Under the direction of chief executive officer L. Bell, B.C. Hydro established a number of

⁴² B.C. Hydro, *Annual Report*, op. cit., (1979-1989).

⁴³ Ibid.

new programs in its pursuit of the many incremental, low-investment actions that are now recognized as having cumulatively significant impacts for balancing supply and demand.

Under the Power Smart Program, started in 1989, B.C. Hydro offers fourteen conservation programs and is developing another nine. The initial goal was to save 2,400 GWh per year by the year 2000, but this objective has been raised to 3,000 GWh and may be increased substantially pending additional research into conservation potential.⁴⁴ In its decision of April 1990 on B.C. Hydro's application to increase rates, the B.C. Utilities Commission considered its own estimate of 4,600 GWh/year over the next fifteen years to be conservative.⁴⁵

The Resource Smart Program (1989) aims at improving the efficiency of existing generating facilities or the installation of generation equipment at hydro storage facilities.⁴⁶ Although B.C. Hydro currently includes only 2,000 GWh from this source in its resource plan, its preliminary research suggests a potential of at least 4,800 GWh.⁴⁷

B.C. Hydro is pursuing co-ordination agreements with utilities in Alberta and the Bonneville Power Administration in the U.S. Pacific Northwest, as well as with the Alcan hydro system near Kitimat. Co-ordination between hydroelectric systems has the same effect as diversifying an investment portfolio; as water runoff in more drainage basins is co-ordinated, the susceptibility to regional variations in precipitation diminishes. Co-ordination with the Bonneville Power Administration and Alcan would increase B.C. Hydro's firm energy supply by at least 1,000 GWh and 260 GWh respectively.⁴⁸ Co-ordination between a thermal and a hydro based system provides a different kind of benefit. The thermal system in Alberta has off-peak capacity that could produce electricity to exchange with B.C. Hydro for peak electricity; a predominantly hydro system tends to not

⁴⁴ B.C. Hydro, *Twenty Year Resource Plan*, op. cit. As a reference point for the electricity quantities detailed in this section, note that the Site C dam is projected to produce an average of 4,730 GWh per year, while the city of Victoria currently uses about 2,400 GWh per year.

⁴⁵ B.C. Utilities Commission (BCUC), *In the Matter of a Rate Increase Application by British Columbia Hydro and Power Authority* (Vancouver: BCUC, 1990), 49.

⁴⁶ For example, the Keenleyside dam, which was constructed to provide storage as part of the Columbia River Treaty, could produce 1,030 GWh of firm electricity if a powerhouse were installed. Since the dam has already been constructed, the incremental environmental impacts of this type of project are negligible.

⁴⁷ B.C. Hydro, *Twenty Year Resource Plan*, op. cit., 18. The 2,000 GWh includes 1,030 from Keenleyside and 970 from several small projects.

⁴⁸ *Ibid.*, 20.

need all its capacity at once, even in peak periods.⁴⁹ Co-ordination with Alberta could provide B.C. Hydro with 1,500 GWh.⁵⁰

4.2 Independent electricity generation potential in B.C.

The policy change with perhaps the broadest implications for the future of electricity generation in the province is B.C. Hydro's initiative to purchase electricity or encourage load displacement from non-utility producers. What was initiated as an effort to elicit a relatively small contribution to system growth requirements has, as in the U.S., expanded into a potentially radical change in electricity generation planning. Unlike the U.S., where PURPA initially determined the size and type of firm involved in independent electricity production, B.C. Hydro's multi-faceted approach has opened the B.C. electricity generation market to almost any potential non-utility producer.

The largest potential independent producer is Alcan. B.C. Hydro recently signed a twenty-year contract to purchase 2,500 GWh per year from that company's expansion of its Kemano hydroelectric facility.⁵¹

The changing regulatory environment in the U.S. is leading to an increase in the sale of electricity between utilities. This potential also exists in Canada. B.C. Hydro foresees the potential to purchase at least another 1,500 GWh from Alberta in addition to the 1,500 GWh provided by system co-ordination.⁵²

Another significant source of non-utility electricity production is B.C.'s pulp and paper mills. Fuelled primarily by chemical recovery liquors and wood waste, these plants cogenerated approximately 2,600 GWh for internal consumption in 1989. B.C. Hydro currently estimates that an additional 1,400 GWh of economic potential are available, and this amount was deducted from the utility's 1989 twenty-year forecast of electricity demand growth.⁵³ However, a recently completed research project estimates that at least another 2,000 GWh are available from this source at a lower cost than the Site C dam.⁵⁴

⁴⁹ This is why hydro systems are called energy (KWh) critical and thermal systems are called capacity (KW) critical.

⁵⁰ B.C. Hydro, *Twenty Year Resource Plan*, op. cit., 20.

⁵¹ Ibid. Due to a recent legal decision on environmental review, the status of this project is uncertain.

⁵² BCUC, op. cit., 46.

⁵³ B.C. Hydro, *Twenty Year Resource Plan*, op. cit., 23.

⁵⁴ T. Mäkinen, "The Electricity Self-Generation Potential of the BC Pulp and Paper Industry," (unpublished M.R.M. thesis, School of Resource and Environmental Management, Simon Fraser University, 1991). This estimate is based on the assumption that B.C. Hydro would negotiate similar contracts and similar technical con-

Small hydro is another potential source of independent power in B.C.⁵⁵ It is currently estimated that approximately 600 MW of firm small hydro potential exists at a cost competitive with the Site C dam.⁵⁶ At a 60 per cent operating rate this capacity would produce about 3,200 GWh per year. B.C. Hydro has begun to solicit proposals and negotiate contracts with small hydro producers.

The wood waste consumed by pulp and paper mills to cogenerate electricity and steam can also be used to produce electricity alone by using conventional steam condensing turbines. This is feasible in the regions of B.C. where there are negligible steam requirements, yet where substantial quantities of excess wood waste are currently disposed of by inefficient burning in beehive burners, creating local air pollution problems.⁵⁷ A recent study which assessed the economics, engineering, and environmental effects of using only half of B.C.'s wood waste surplus to produce electricity from condensing technologies identified a potential for almost 400 MW of capacity, annually about 2,900 GWh of electricity, again at a cost competitive with electricity from the Site C dam and with significant local environmental benefits.⁵⁸ B.C. Hydro has already begun to negotiate contracts with proponents of steam condensing, wood waste-fired technologies.

The focus thus far has been limited to non-utility generation using small hydro and waste fuels. These types of facilities would be equivalent to QFs under the PURPA legislation in the U.S. However, estimating electricity production potential from non-utility generators is not simply an economic and engineering question. It is also a policy question that depends on the government's intended role for B.C. Hydro. If the current policy continues, that B.C. Hydro will not be privatized and will retain responsi-

ditions to those which were recently concluded with Howe Sound Pulp and Paper for its mill at Port Mellon. This mill has increased its self-generation capacity to 112.5 MW, an annual production of 745 GWh. Roughly half of this generation capacity is cogeneration.

⁵⁵ There are many different definitions for small hydro, but generally it is safe to refer to projects under 5 MW as small relative to the projects normally considered by B.C. Hydro.

⁵⁶ G. McDonnell, "The Potential for Development of Independent Power Projects Using a Contract Modelled After the Rate Application," (Vancouver: B.C. Utilities Commission, 1990), Intervention in the B.C. Hydro Rate Application.

⁵⁷ The recent policy statement of the provincial Ministry of Energy, Mines and Petroleum Resources requires B.C. Hydro to pay a premium price for electricity from projects that seek to utilize wood waste to generate electricity. B.C. Ministry of Energy, Mines and Petroleum Resources (MEMPR), *New Directions for the 1990s*, (Victoria: B.C. MEMPR, 1990).

⁵⁸ M. Jaccard et al., "Electricity from Wood Waste: Integrating Energy and Environmental Analysis in British Columbia," *Energy Studies Review*, 1:2 (1989): 106-14.

bility for major new hydroelectric developments (except for projects in the jurisdictions of Alcan and WKPL), then independent power production can conceivably come from any energy source other than large scale hydro.

Indeed, B.C. Hydro's eligibility requirement for non-utility generators is much closer to the current, broader U.S. definition of an independent power producer. This means that B.C. Hydro will consider offers to supply electricity with no preconditions about the type of technology or the form of energy. When the possibility for non-utility generation is extended to all energy forms, the potential increases dramatically.

One example is cogeneration. In B.C., cogeneration has primarily been associated with pulp and paper mills, but smaller scale possibilities were not seriously pursued in the past. Cogeneration potential exists wherever significant amounts of steam are produced. Potential cogeneration sources include other industrial steam applications, municipal waste incinerators, and space heating systems in large institutional buildings (e.g. hospitals) and office buildings.⁵⁹ With the change in policy at B.C. Hydro, energy managers at these types of facilities are just beginning to investigate the feasibility of becoming non-utility generators. If the U.S. experience provides a reliable indication, cogeneration offers may far exceed B.C. Hydro's expectations.

Much of the new non-utility power production in the U.S. is attributable to highly efficient natural gas-fired technologies. These technologies are favoured for several reasons: the current low price of natural gas, the low capital cost per KW of capacity of natural gas-fired technologies, the small scale and quick construction time of these technologies, and the environmental acceptability of natural gas relative to oil, coal and nuclear. If natural gas using technologies (cogenerating or other) were allowed to fully compete for new capacity in B.C., they would be highly competitive at current prices.

Two other potential sources are thermal coal and medium size hydro. B.C. is endowed with significant potential for both of these resources. However, development of either resource may involve controversial environmental impacts.

The response to B.C. Hydro's first request for proposals (RFP) for independent power production (December 1988) provides a preliminary indication of how diverse and substantial this new approach to electricity generation may be. The RFP sought offers of electricity supply and/or load displacement (large and small projects) to meet a stated need for 150

⁵⁹ A. Reinsch and E. Battle, *Industrial Cogeneration in Canada: Prospects and Perspectives* (Calgary: Canadian Energy Research Institute, 1987), no. 24.

MW. It received proposals for over 1,600 MW.⁶⁰ By the end of 1990, contracts had been signed for nine small hydro projects totalling 41 MW, and for three larger projects totalling 210 MW; these three included medium hydro (50 MW), wood waste (55 MW), and natural gas (105 MW).⁶¹

Recent experience of Ontario Hydro parallels that of B.C. Hydro; in the few years since the Crown utility has begun to seriously advertise its interest in purchasing more independently generated electricity, its estimates of this potential have been revised upwards several times. As of October 1990, Ontario Hydro estimated that at least 60 per cent of all new electricity supply in Ontario would come from independent producers.⁶²

4.3 Electricity Demand and Supply in B.C. in the 1990s

In this section, we explore B.C. Hydro's likely activities over the next decade by assessing the combined effects of (1) the corporation's recent supply and demand policy initiatives, (2) projected growth in population and economic activity, and (3) government policy on the role of large hydro projects in economic development. Table 1 and figure 1 summarize the cumulative effects of the diverse resource options that B.C. Hydro is pursuing. Large hydroelectric projects have been excluded in order to focus on the magnitude of what is, for B.C. Hydro, non-traditional resource potential. In other words, table 1 and figure 1 illustrate the extent to which B.C. Hydro's new initiatives are likely to shift the corporation away from its former primary role of designing and constructing major hydroelectric projects. The year 2005 has been chosen in order to ensure coverage of B.C. Hydro's activities over the entire decade of the 1990s; if a major hydroelectric project is required before 2005, B.C. Hydro must begin construction at least five years in advance.⁶³

The growth assumptions about Gross Provincial Product, provincial population and electricity consumption are from B.C. Hydro's two most recent load forecasts.⁶⁴ An annual average electricity demand growth rate of 2.8 per cent would lead to an increase in B.C. Hydro's electricity output

⁶⁰ B.C. Hydro, *Independent Power Production in the 90s* (Vancouver: B.C. Hydro, 1990), Proceedings from a Workshop for Private Power Producers.

⁶¹ "Hydro switches off megaprojects," *The Vancouver Sun*, 8 January, 1991.

⁶² "Hydro to tap private producers," *The Globe and Mail*, 17 October, 1990.

⁶³ For example, the Site C Dam is estimated to require seven years for construction.

⁶⁴ B.C. Hydro, *Twenty-Year Resource Plan*, op. cit., (1989); and B.C. Hydro, *Electric Load Forecast* (Vancouver: B.C. Hydro, 1990). The results of different growth rates before and after 1999 have been simplified into a single average annual growth rate.

TABLE 1
B.C. Hydro Demand and Supply Balance to 2005

Demand Assumptions^a

	1989	2005	Annual Growth
Population (millions)	3,053	3,872	1.5%
GDP (\$1981 millions)	47400	71500	2.6%
Elec. Consumption (GWh)	43600	67800	2.8%
Incremental Load Growth (GWh)		24200	
Elec. Price (real) — constant or slightly declining			

Resources other than Large Hydro^b

Code to Figure 1	Resource	Potential to 2005 (GWh)	Cents/KWh (1989) Cost in
A	Coordination ^e	2760	1.5 – 2.5
B	Power Smart ^e	4000	2 – 3
C	Burrard Thermal ⁱ	3170	1.5 – 4
D	Purchases ^e	4000	2.5 – 3.5
E	Extra P&P Cogen. ^f	2000	2 – 4.5
E	Resource Smart ^{d, e}	2000	3 – 3.5
E	Other Cogen. ^h	500	2 – 4.5
E	Other IPP ^j	2000	2 – 4.5
F	Small Hydro ⁱ	1000	3 – 4.5
G	Wood Waste ^g	1000	4 – 5
G	Columbia Treaty ^j	3230	4 – 5
	TOTAL	25660	

^a Demand assumptions are taken from B.C. Hydro's Electric Load Forecast (1990) and Twenty-Year Resource Plan (1989).

^b Resources are those which are lower in cost than the estimated 5 cents/KWh (\$1989) of the Site C Dam.

^c The estimate of 4000 GWh exceeds B.C. Hydro's last published estimate of 3000 GWh but is less than the 4600 GWh conservatively estimated by the BCUC in its decision on B.C. Hydro's 1990 application for a rate increase.

^d The estimate of 2000 is especially conservative given B.C. Hydro's 1989 estimate of 4800 GWh of potential.

^e B.C. Hydro, *Twenty-Year Resource Plan*, 1989.

^f T. Makinen, 1991.

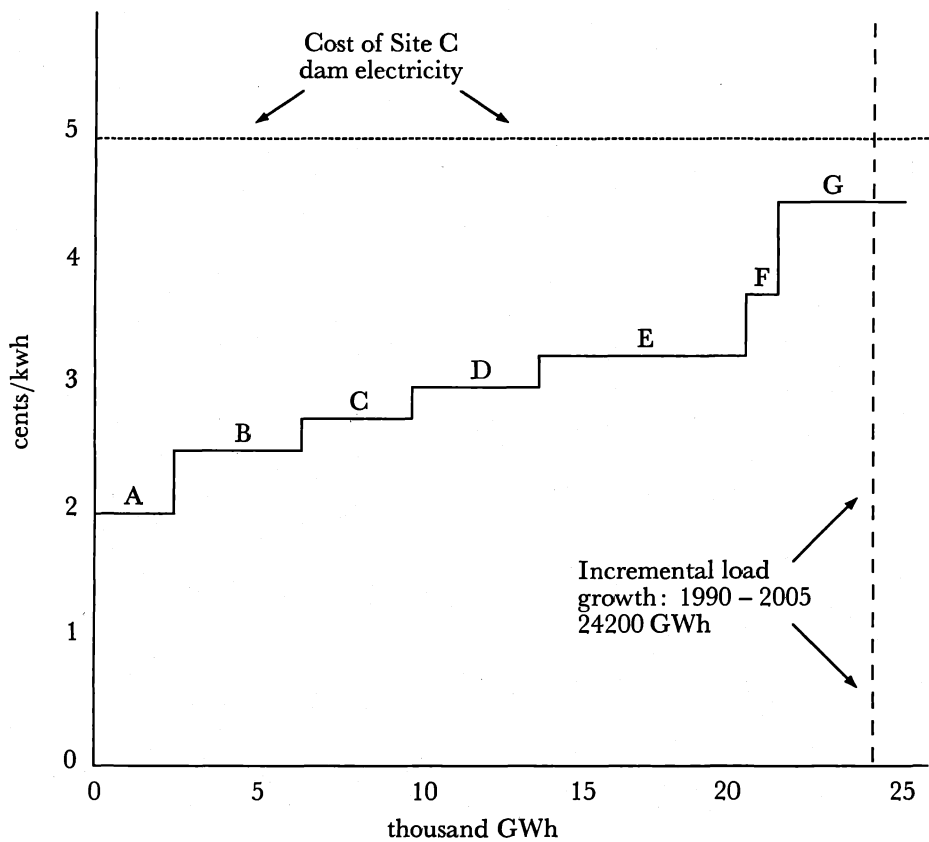
^g M. Jaccard, et al., 1989.

^h This is a very conservative estimate of non-pulp and paper cogeneration potential.

ⁱ G. McDonnell, 1990.

^j BCUC, 1990.

FIGURE 1
B.C. Hydro Demand and Supply Balance to 2005



N.B. See column 1 of table 1 for a listing of the resource options corresponding to the letters on the graph.

from 43,600 GWh in 1989 to 67,800 GWh in 2005, an expansion of 56 per cent. This increase is equivalent to the average output of five Site C dams. Electricity demand is estimated under the assumption that the efficiencies of new electricity-using equipment will be the same as the average efficiencies of existing equipment stocks. In this way, the end-use efficiency improvements associated with the Power Smart demand conservation programs are not double counted. Electricity prices are assumed to remain constant in real terms. This is consistent with the estimated costs of resources listed in table 1; i.e., if these costs are reliable and these resources are developed, the average cost of electricity from the B.C. Hydro system should not dramatically increase.

The costs and magnitudes of alternative resources come from recent estimates of B.C. Hydro, the B.C. Utilities Commission, and independent studies, as referenced in section 4.2. Considerable uncertainty is associated with some of these resources. Where uncertainty is high, we have chosen to be conservative in estimating the resource's potential magnitude.

The Power Smart (conservation) estimate of 4,000 GWh is more conservative than the recent estimate of the B.C. Utilities Commission.⁶⁵ The Resource Smart estimate is less than half the amount identified by B.C. Hydro.⁶⁶ The Coordination and Purchases resources are much more certain, so these are as estimated by B.C. Hydro. The electricity resources which might be developed by independent power producers include: (1) additional cogeneration from pulp and paper mills,⁶⁷ (2) a portion of the total provincial potential for wood waste-fired condensing turbines, (3) cogeneration from all industrial and institutional sources other than pulp and paper mills, (4) a portion of the provincial potential for small hydro, and (5) all other types of independent power production. The total estimate from these five sources is 6,500 GWh. Although the mix is different, this total is comparable to the 6,450 GWh from IPPs and pulp and paper cogeneration estimated by the BCUC.⁶⁸ If operated on seasonally available natural gas, the Burrard thermal plant would annually generate 3,170 GWh. However, this represents only a 40 per cent utilization rate of the

⁶⁵ See table 1, note 3.

⁶⁶ See table 1, note 4.

⁶⁷ The B.C. Hydro demand forecast already includes the assumption that pulp and paper mills will increase their cogeneration of electricity by 1,400 GWh. Therefore, B.C. Hydro had subtracted this total from the estimate of load growth. The cogeneration included here is in addition to that 1,400 GWh.

⁶⁸ Our estimate is higher for pulp and paper cogeneration and wood waste-fired condensing electricity generation because it is based on the recent research by M. Jaccard et al., *op. cit.*, (1989); and T. Makinen, *op. cit.*, (1991).

900MW plant. While long run gas contracts would allow 6,300 GWh (at 80 per cent utilization), there is some question about local concerns for air emissions in the lower mainland area. Finally, the downstream benefits from the storage dams built for the Columbia River Treaty begin to return to B.C. in 1998. These are estimated by B.C. Hydro and the BCUC at 3,230 GWh per year.

Table 1 and figure 2 indicate that the total non-traditional resource potential to the year 2005 is more than sufficient to meet the most probable forecast of demand growth to the year 2005. This implies that B.C. Hydro will not be required by domestic energy markets to undertake the design and construction of any major hydroelectric project over the next decade. Thus, the transformation of the corporation, which has been so substantial during the 1980s, seems set to continue through the 1990s.

The role for B.C. Hydro implied by table 1 and figure 2 has implications for the internal organization of that corporation as well as for the overall organization of electricity production and management in B.C. We address this issue in Section 5. We conclude this section with an assessment of two factors which may lead to a different outcome than that portrayed by table 1 and figure 2.

First, forecasting electricity demand is fraught with uncertainty. For example, if the annual growth rate of electricity demand is much higher, say 3.5 per cent, the total demand in 2005 would be 75,600 GWh, an increase of 32,000 GWh. B.C. Hydro would then be required to find 8,000 GWh more than in the scenario of table 1 and figure 2. This may require the construction of one or two large hydro dams.

However, the conservative estimates in table 1 suggest that a more rigorous pursuit of alternative resource options could unveil significantly greater potentials. For example, the Electric Power Research Institute, a utility-sponsored research agency, estimates that up to 27 per cent of current U.S. electricity consumption could be saved by cost-effective conservation measures.⁶⁹ In B.C. this would imply that the Power Smart conservation potential may be as high as 8,000 to 9,000 GWh instead of the 4,000 GWh used in table 1. Detailed analysis of several of the other resource options in table 1 also leads to significant increases. As a result, the potential of some of these resources can undoubtedly be increased if necessary to offset greater than expected growth in electricity demand, at least over the next fifteen years.

⁶⁹ A. Fickett et al., "Efficient Use of Electricity," *Scientific American*, September 1990, 65-74. Note that this estimate is based on hindsight evaluation of the success rates and costs of utility programs.

Second, what if the B.C. government once again becomes enthusiastic about the economic development potential of large hydroelectric projects?⁷⁰ The Social Credit government during the 1980s never completely abandoned this idea. While the policy of the B.C. New Democratic Party (NDP) emphasizes conservation and smaller scale alternative resources over large hydro projects, this can change. The NDP government of Manitoba built a large hydroelectric project in the 1980s to serve U.S. export markets. Furthermore, over the next fifteen years the potential export market on the west coast of the U.S. should increase significantly, especially as utilities in that region begin to exhaust their own conservation potential and to contemplate socially and environmentally sensitive capacity expansions.

Under the Social Credit government's direction, B.C. Hydro has created a subsidiary, POWEREX (1988), responsible for negotiating and marketing firm electricity exports from B.C. to the U.S. Electricity for export could be produced by B.C. Hydro at new large facilities, by sale of the Columbia River Treaty downstream benefits, or by independent power producers. Pursuit of this latter option was initiated by POWEREX with its 1989 Request For Proposals.

However, governments in B.C. have never dared develop electricity generation potential explicitly for export, and political risks remain. Therefore, while electricity export markets should emerge over the next decade, it is not certain that an explicit export policy will be pursued, and even less certain that B.C. Hydro would ever be directed to build large hydroelectric projects for this purpose. The most likely scenario is that B.C. Hydro's role in the 1990s will be one of *managing instead of building*. In the final section, we turn to some of the implications of this new role for the management and regulation of B.C.'s electricity system.

5. *Implications for Managing B.C.'s Electricity System*

The analysis of the previous section suggests that the transformation of B.C. Hydro in the 1980s will continue in the 1990s. The Crown corporation will not be engaged in the design and construction of major hydroelectric projects. Instead, its role will primarily be one of management and co-ordination of an increasingly complex electricity system, involving

⁷⁰ Recent research suggests that even the assumption about the macroeconomic benefits of hydroelectric development may have been overstated, especially when compared to the employment creation potential of electricity conservation programs. M. Jaccard and D. Sims, "Employment Effects of Electricity Conservation: The Case of British Columbia," *Energy Studies Review*, 3:1 (1991): 35-44.

bidding procedures for independent power production, co-ordination and purchase agreements with other utilities, provision of transmission services, and implementation of demand-side management programs. Each of these components of the electricity system is associated with specific requirements for the internal structure and expertise within B.C. Hydro, as well as for the overall institutional arrangements associated with the management of the B.C. electricity system.

The issues raised by this new corporate role are substantial and their detailed examination would require a separate paper. In this concluding section, we provide a glimpse of what some of the key organizational and management issues will be. The section focuses first on B.C. Hydro and then on the challenges to management of an electricity system increasingly reliant on independent power production.

5.1 Changes in the Organization and Functions of B.C. Hydro

First, an obvious necessity at B.C. Hydro is the reduction in personnel with expertise in major hydroelectric development. Because the postponement of the Site C dam in the 1980s led to the elimination of many project development positions, most of this change has already been completed.

Some would argue that this alone can have interesting implications for management attitudes at B.C. Hydro. As fewer and fewer employees depend upon hydroelectric projects for job security, the corporation may become more open to alternative cost-effective resource options.

Second, the electricity system that B.C. Hydro must manage in the future will be much more complex, requiring co-ordination between the corporation, industry, and the public. In the past, the different sectors of the electricity market — production, transmission, and distribution — were all internal operations of B.C. Hydro. This situation is already in the process of a profound transformation. B.C. Hydro personnel will be increasingly required to work closely with a vast array of heterogeneous groups, ranging from households to large industries to various sizes of independent power producers.

Two examples provide an indication of the diversity of expertise that will be required of B.C. Hydro staff. The Power Smart demand-side management initiative requires expertise in: engineering and economics to select conservation targets; advertising and marketing to design, promote, and deliver conservation programs; finance and accounting to administer monetary incentives; and end-use and econometric modelling to monitor programs and assess their implications for demand forecasts. The indepen-

dent power producers initiative requires expertise in: project engineering to assess feasibility and reliability of electricity production and cogeneration technologies; accounting and finance to assess financial viability; law and economics to negotiate contracts and establish bidding procedures; forecasting to assess resource potential; natural resource management to assess the environmental and resource impacts of alternative technologies; and system engineering to operate an electricity system comprising many independent producers.

Third, in addition to diversifying the range of expertise within the corporation, B.C. Hydro must also re-organize the relationship between corporate divisions in order to co-ordinate the much greater number of functions now involved in resource planning. In the past, resource planning was seen as a relatively simple exercise. Because demand growth was primarily beyond the reach of the corporation, it was forecast. Because new supply development was considered to be the responsibility of the corporation, it was planned.

This convenient dichotomy has been transformed. First, new demand-side management programs introduce a degree of planning of demand growth, although forecasting is still also necessary. Second, by removing new supply from the corporation's exclusive control, independent power production requires B.C. Hydro to augment its conventional supply planning with various techniques of supply forecasting. For example, B.C. Hydro now must try to forecast the long-run potential for customer self-generated electricity in order to determine the need to develop other resources. As a consequence, many corporate departments should now have a formalized role in the development of the twenty-year resource plan. For example, departments responsible for customer services and demand-side management will have important information for demand forecasting on the penetration rate and performance characteristics of electricity efficient technologies.

Over the last few years B.C. Hydro management has responded to these new challenges with several internal re-organizations. This transformation is likely to continue as the new functions of the corporation manifest themselves.

5.2 Management and Regulatory Issues of the Emerging B.C. Electricity System

The emerging B.C. electricity system has implications that extend beyond the organizational and functional concerns of B.C. Hydro. A major reason

is that much of the incremental additions to the B.C. electricity generation system will be designed, constructed, and operated by the private sector. This outcome, which is likely regardless of which provincial political party is in power, raises a new set of challenges to the institutions that currently manage and regulate the B.C. electricity system.

One key issue is the establishment of economically efficient and fair rates and procedures for the purchase of electricity from independent power producers. Efficiency involves ensuring the development of resources in sequence from lowest to highest cost.⁷¹; purchase rates should ensure that projects which are less costly than the Site C dam are developed prior to it. Efficiency also involves ensuring that environmental costs are somehow factored in, either explicitly or implicitly. Considerable effort has recently been directed to this end in several areas of the U.S.⁷²

The rates and procedures must be fair to British Columbia residents by not awarding all the economic rent from natural resource endowments to private interests; in bilateral negotiations, or in some type of competitive closed bidding procedure, B.C. Hydro can set purchase rates that do not award excessive profits.⁷³ Thus, if an independent producer's levelized costs are far below the cost of the Site C dam, the price at which that producer sells to B.C. Hydro should also be lower. The rates must also be fair to independent producers. For example, independent producers have higher taxes and higher costs of debt and equity capital than B.C. Hydro. Consequently, B.C. Hydro should be prepared to pay a premium to ensure the development of those private projects which, although they appear to be uneconomic relative to the Site C dam, would be economic if proponents had the same financial support as B.C. Hydro.

In the U.S., it has largely been the responsibility of utilities commissions to design electricity purchase rates and independent power bidding procedures. Since B.C. Hydro is publicly owned, one could argue that impartiality and the public interest are well served by leaving this responsibility to the Crown corporation. However, since B.C. Hydro is both setting the

⁷¹ This is consistent with the concept of least cost planning, as discussed in Section 3.3.

⁷² S. Cohen et al., "Environmental Externalities: What State Regulators Are Doing," *The Electricity Journal*, 3:6 (1990): 24-35. In 1990, the B.C. government directed B.C. Hydro to apply a premium to the price it is willing to pay for electricity generated by environmentally desirable projects.

⁷³ Various types of bidding procedures are being developed by utilities and utility commissions in the U.S. In competitive bidding, an independent power producer makes a closed bid to sell electricity to the utility at a price which is largely determined by the producer's expected rate of return and competitive position, not by the utility's long-run cost of new self-produced generation.

rules and negotiating from one side of the table, it may be preferable to involve the B.C. Utilities Commission as a third party.

A second key issue is the appropriateness of existing provincial procedures for reviewing energy projects. When the current energy project review process was created in 1980, its major focus was intended to be large projects proposed by B.C. Hydro. Indeed, projects of less than 20 MW were exempted from the review process.⁷⁴ If the 1990s are instead characterized by many private, smaller-scale projects of great diversity (form of energy, size of company, environmental impacts, etc.), how will the review process function and, especially, how will it deal with broader social and environmental questions?

For example, while it is frequently assumed that small hydro projects are environmentally benign, recent experience with site assessment in the U.S. Pacific Northwest has revealed that small hydro often conflicts with other land uses, including sports fishing, wildlife habitat, native land claims, nature parks, wilderness recreation, and other medium and large scale hydropower sites.⁷⁵ The response of the Northwest Power Planning Council has been to establish a land use assessment and trade-off technique that covers all relevant drainage basins, all potential hydro sites (small, medium, and large) and all competing land uses. While this review process is still in its infancy, it may provide a useful model as B.C. prepares to deal with a wave of small hydro project proposals.

The need to deal with cumulative effects is not unique to small hydro. Any review process that incrementally assesses individual projects will be inadequate for assessing some of the broader issues facing electricity management in the coming decades. One issue is the growing concern for reducing the emissions of greenhouse gases, which are often the by-product of burning fossil fuels for energy. How can a review process that focuses on individual projects also respond to aggregate emission targets? Another issue is energy security. A preference among private electricity producers for natural gas, because of its current low price and quick investment pay-back, may not be in society's long-term interest, especially if this increased demand contributes to scarcity and significantly higher prices in the future. Finally, another issue is interenergy substitution. Society may not be well served if its publicly-owned electric utility subsidizes consumers and industry to switch from electricity to natural gas. This would be especially

⁷⁴ A. Thompson et al., *Energy Project Approval in British Columbia* (Vancouver: Westwater Research Centre, 1981).

⁷⁵ D. Lee and A. Kneese, "Fish and Hydropower Vie for Columbia River Waters," *Resources* 94 (Winter 1989): 1-4.

problematic if the latter market were dominated by privately owned utilities, more interested in short-term sales maximization than long-term social economic efficiency and energy security.

The concerns expressed here may not be appropriate to the regulatory mandate of an agency such as the B.C. Utilities Commission. If this is so, then some other type of institutional arrangement may be required. The creation of the Northwest Power Planning Council in the U.S. provides a model of the kind of institution that can address broader long-term planning questions of an electricity system that is less and less under the exclusive control of a publicly owned natural monopoly utility. Is it time for a B.C. Energy Council?

6. Conclusion

Prior to the 1980s, electric utilities in industrialized countries focused almost exclusively on the construction and operation of ever-larger generation facilities in what was assumed to be in all respects a natural monopoly industry. However, in that decade utilities and their regulators became aware of the emerging potential for smaller-scale competition in the generation of electricity and for cost-effective electricity conservation. While this new thinking originated in the U.S., it is spreading to Canada, especially to the management of B.C. Hydro. This new approach has important implications for the personnel, functions and organization of B.C. Hydro, as well as for other institutions and procedures associated with the management and regulation of the B.C. electricity system during the next decade and into the twenty-first century.