ENERGY IN BRITISH COLUMBIA:

REGULATORY STRUCTURES

AND

INTEGRATED RESOURCE PLANNING

by

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EXECUTIVE SUMMARY

Concern over energy planning processes has been growing in recent years in Québec as well as throughout Canada. Integrated resource planning is now widely recognized as an effective mechanism for ensuring that all approaches to meeting future energy needs are considered on an equal footing and that public concerns and values are incorporated into the planning process. Of all the Canadian provinces, British Columbia has gone farthest in applying integrated resource planning. IRP is now required of all electric and gas utilities in B.C. by the B.C. Utilities Commission.

In the most basic sense, the goals of IRP can be described as follows: to plan for the future supply of energy services at least cost to society, not only through actions that increase the amount of energy available, but also through those that affect how it is used, and taking into account costs of energy development which are not borne by the utility (externalities such as environmental or social impacts). Recognition of the uncertainties surrounding every element of energy planning is also central to the IRP approach. At the same time, IRP is seen increasingly as an opportunity for public involvement in high-level, long-term energy planning, which serves the twin goals of ensuring that major energy decisions take public concerns into account and of contributing to public confidence in and support for utility decision-making.

IRP began in the United States and has been widely applied there, so it is not surprising that most of the IRP literature takes for granted many aspects of the electric power industry in the U.S. These characteristics include a utility industry which is predominantly privately owned and which is regulated by state boards or commissions. Despite the fact that IRP was born in the American Northwest, where hydro power predominates, most of the literature devotes far more attention to the impacts and issues related to fossil fuel energy systems than hydro — probably because there are few if any major hydro projects now under consideration in the U.S.

For these and other reasons, the implementation of IRP in the Québec context raises a number of interesting questions. What would it mean for a large Crown utility like Hydro-Québec to apply IRP? Should it be applied only to the electric industry, or also to natural gas? What about the rest of the energy sector? Can a Crown utility be regulated in the same way that private utilities are, and should it? How can methods and procedures developed to assess the externalities of fossil fuel power plants be adapted to account for those of hydro developments, the impacts of which are more local but more complicated to assess? These and other questions must be answered before IRP structures can be developed in Québec.

At the same time, rapid changes are underway in the American electric industry that may significantly affect IRP and the way it is applied. These changes include increased competition at both the wholesale (generation) and retail (distribution) levels. The forces leading to these changes are particular to the U.S., though they are not unique to it. Any application of IRP in Québec will have to carefully assess these trends and how they will affect our electric industry.

While these questions can ultimately only be answered here in Québec, it may be of interest to look at experiences elsewhere in Canada — particularly in provinces that share some of Québec's characteristics. In this sense, British Columbia is particularly pertinent. Its electric industry has striking similarities to Québec's.

Like Québec, B.C.'s electric supply is based on hydroelectricity, which accounts for 90% of its installed capacity (vs. 95% for Québec). Like Québec (and unlike much of the rest of North America), its periods of greatest electrical demand are in the winter, and electric space and water heating makes up a significant part of the load (though much less than in Québec). And like Québec, the B.C. electric industry is dominated by a Crown utility. Unlike Hydro-Québec, B.C. Hydro has been fully regulated since 1980.

Until 1980, B.C. Hydro was under the direct control of the provincial legislature; its construction projects were only subject to public review insofar as they required water licenses. However, this arrangement came under broad attack in the context of the hearings on the High Revelstoke Dam project in 1976. In those hearings, interveners insisted on addressing issues such as project justification, energy planning, supply and demand forecasts and environmental and social impacts of the project.

As a result of this controversy — in particular concerning the dam's environmental impacts and the credibility of the domestic demand forecasts on which the decision was based — the Social Credit government submitted legislation in August 1980 to reform the regulation of the province's energy industry. Under the new act, B.C. Hydro was placed under the regulatory control of the new B.C. Utilities Commission.

It took several years before the Utilities Commission's oversight began to affect B.C. Hydro in a substantive way, but by the late 1980s, Utilities Commission oversight had played an important role in two key changes at B.C. Hydro: the abandonment of the Site C hydro project, and the shift in corporate philosophy to favour conservation over generation.

The B.C. Utilities Commission

The primary responsibility of the B.C. Utilities Commission is "to ensure that the rates charged for energy are fair, just and reasonable, and that utility operations provide safe, adequate and secure service to their customers." Since 1992, as a means of judging the prudency of investments and hence the justification of rates, the Utilities Commission has required the utilities it regulates to carry out least-cost integrated resource planning.

Under the *Utilities Commission Act,* the Commission has considerable independence and powers, including the power to initiate inquiries or hearings on any matter within its jurisdiction. It has power equivalent to that of the provincial courts to require testimony and access to documents. The Commission is funded through a levy on the sales of all regulated utilities. Its budget in 1993 was just over $3 million.
Regulation in the electric industry was traditionally based largely on the "natural monopoly" characteristics of the electric industry and the fact that it engenders significant levels of externalities. In exchange for permitting a firm to reap the benefits of such a monopoly, and to prevent it from extracting excessive profits from a captive public, many governments have chosen to place such a firm under regulatory controls. A second justification for regulation is to respond to the growing recognition that significant externalities (costs or benefits borne by third parties) are associated with electric generation and transmission.

These factors have in the past led Canadian governments to intervene either through regulation or through public ownership of generating resources, but not both. In a recent article, B.C. Utilities Commission chair Mark Jaccard describes the problem with public ownership as a "principal-agent" problem. "According to this concept, the publicly owned corporation is an agent of government assigned to meet the government's objectives. However, the agent may have different objectives than government and as a result may frustrate or at least fail to achieve the latter's objectives."[1]

The solution selected by British Columbia was to graft a regulatory apparatus onto the public ownership model, demonstrating that regulation is in fact not incompatible with public ownership. As the B.C. experience demonstrates, the application of a regulatory regime to a Crown utility offers considerable benefits, with respect both to transparence and public accountability, on the one hand, and to the quality and integrity of the energy planning process *per se,* on the other. While public ownership serves important goals, it is not in itself adequate to ensure that societal priorities are reflected in energy choices.

Even when the utility is publicly owned, a strong argument can be made that rate regulation imposes greater discipline on the utility with respect to its expenditures, and greater transparence as well, which leads to increased public confidence. It is thus an important complement to IRP.

The B.C. Energy Council and the Crown Corporations Secretariat

Two other energy-related bodies were created in B.C. in the early 1990s: the B.C. Energy Council and the Crown Corporations Secretariat.

The B.C. Energy Council, which was disbanded in 1994, was under mandate to develop a sustainable energy strategy for B.C., based on broad public consultation. Its structure and mandate were

[1] Mark Jaccard, "Canadian Electricity Markets and the Future Role of Government," *Energy Studies Review*, 6:103-126 (1994), p. 15.

determined after looking closely at similar institutions in the United States, particularly the California Energy Commission and the Northwest Power Planning Council.

The recommendations of the B.C. Energy Council are found in its final report, *Planning Today for Tomorrow's Energy: An Energy Strategy for British Columbia,* released on November 22, 1994. This 150-page report, written in clear and direct language, starts with the idea that "business-as-usual is not sustainable," and attempts to determine both what energy sustainability would look like and how it can be achieved. *Sustainable energy systems* are those which are fully renewable and which have acceptable environmental, social, health and cultural impacts. The report also seeks to define *transitional energy strategies* — those which do not themselves meet all these criteria but which will ease the transition to a fully sustainable economy.

The other agency discussed, the Crown Corporations Secretariat, is charged with overseeing the relationship between the government and all the Crown corporations. Its primary goal is to promote synergies between the various Crown corporations, and it has played an important role in the management of B.C. Hydro, acting as an interface between the government and the Board of Directors. While it appears to have produced very positive results, its role is not essential to the B.C. model of energy regulation.

Environmental assessment

A new Environmental Assessment Act was passed in 1994 by the B.C. Legislature. The new law changes the procedures for environmental assessment of energy-related projects in several significant ways. The new regime dramatically reorganizes the relationship between environmental assessment and energy planning: energy projects will only be permitted into the environmental assessment process if they have already been approved by the Utilities Commission as part of an integrated resource plan.

This simple device resolves the contradiction that has plagued decision-making on energy projects in Québec and in many other jurisdictions, where environmental review boards find themselves having to assess every aspect of a utility's energy planning in order to assess the justification of the project before them. While most observers agree that this is an anomaly, it has been almost impossible to avoid, since the environmental impacts of energy development can only be considered acceptable in relation to both the need for the energy and the available alternatives.

However, for such an approach to be credible, it would have to be based on an IRP process which is strong, transparent and independent. Even in B.C., which has undertaken the changes described in this paper at an extraordinary pace, this step was not taken until the Utilities Commission had been in place for 14 years, and had been requiring IRP for two years. To attempt this kind of restructuring before the IRP/regulatory process is mature would be to invite disaster.

Summary and conclusions

Over the last 15 years British Columbia has experimented with a variety of structures to implement these planning and regulatory concepts. These elements are summarized in the following table. In a final column, it also describes the way these issues are handled in Québec at this time.

	BRITISH COLUMBIA				QUÉBEC
	PRE-1980	1980-1992	1992-1994	1995-	
ENERGY POLICY	Ministry		Ministry, with advice from Energy Council and Utilities Commission	Ministry, with advice from Utilities Commission	Ministry
RATES	Regulated for private utilities, B.C. Hydro rates set by Cabinet	Rates for all utilities, including B.C. Hydro, set by Utilities Commission			Hydro-Québec rates set by Cabinet; gas utilities' rates set by Régie du gaz
RESOURCE PLANS	Budgets for private utilities approved by Utilities Commission; B.C. Hydro's Development Plans approved by Cabinet		IRP required by Utilities Commission		Hydro-Québec's Development Plans approved by Cabinet
ENVIRONMENTAL ASSESSMENT	Hearings by Water Comptroller (for hydro projects only) (justification and impacts)	Hearings by Utilities Commission (justification and impacts)		Prior approval in IRP required; hearings by Environmental Board (impacts only)	Hearings by BAPE or JBNQA committees (justification and impacts)
EXPORT AND CONSTRUCTION PERMITS	Cabinet	Utilities Commission (Cabinet approval for major projects)			Cabinet

With respect to energy policy, actual policy development has always remained with the Ministry, as it does in Québec. However, since 1992 it has benefited from advice based on public consultations carried out by two independent agencies, the Utilities Commission and the (now defunct) Energy Council.

As for ratemaking, until 1980 B.C.'s structure was similar to that now in effect in Québec: rates charged by private utilities were set by a provincial regulatory body, while the Crown electric utility's rates were set directly by Cabinet. That structure was changed in 1980 by the *Utilities Commission Act* — a change which has had profound repercussions on energy planning in B.C. The Utilities Commission created by that Act, which has full regulatory control over B.C. Hydro (except for its bond issues, which are controlled directly by the government), has been the driving force behind many of the changes that have taken place since.

The most important of these changes concern capital spending — major investments in energy resources. Even after 1980, the only way the Utilities Commission could influence capital spending was through its oversight of capital spending budgets. It was only with the promulgation of the Commission's Integrated Resource Planning Guidelines in 1992 that it began to play an major role in overseeing fundamental energy choices, based on a rigorous comparison of all the options.

One of the primary benefits of this IRP process, noted by interveners, Commission staff and utilities as well, is that it provides a public forum for a careful examination of the choices leading up to the decision to develop a major energy resource. In so doing, it has both improved the rigour of resource planning and significantly reduced the level of public controversy surrounding such plans.

Under the *Environmental Assessment Act of 1994,* energy projects are not even allowed to apply for environmental permits unless they are part of an IRP which has already been approved by the Utilities Commission. Thus these hearings, which will take place before an Environmental Board, will deal only with environmental issues; since they will already have passed through a rigourous IRP process, there would be no need for the Environmental Board to address project justification. The Utilities Commission also has a final word after the environmental hearings; if mitigation costs or a changing energy situation have made the project less attractive, it can be reconsidered in light of this new information.

Many of the problems that these structures were designed to meet are still vital and divisive problems in Québec and in many other parts of the world. It will be up to policy makers and the public to find the particular set that is best adapted to the particular characteristics of Québec.

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INTRODUCTION

Issues concerning energy planning have gradually come to the fore in Québec over the last few years. Since the early 1980s, there has been an ever increasing demand for a public debate on energy. By 1994, this call had achieved wide, mainstream support, and, late in the year, the Parti Québécois Government announced that it would carry through with its electoral promise to hold such a debate.

The energy-related issues behind these developments are well known in Québec: opposition from Native and environmental groups to large-scale hydro development, broad public opposition to fossil fuel power plants and to nuclear power, growing interest in conservation and alternative energy sources like wind.

At the same time, the approach to energy planning known as integrated resource planning (IRP) has gained increased prominence in Québec. Since 1993, the Government of Québec has made it clear that it intends to implement IRP as the basis for a revised energy policy, and this has been the subject of a consultation process in 1994. Now, at the beginning of the public debate process, it appears clear that the IRP is likely to play an important role in Québec's energy future.

In the most basic sense, the goals of IRP can be described as follows: to plan for the future supply of energy services at least cost to society, not only through actions that increase the amount of energy available, but also through those that affect how it is used, and taking into account costs of energy development which are not borne by the utility (externalities such as environmental or social impacts). Recognition of the uncertainties surrounding every element of energy planning is also central to the IRP approach. At the same time, IRP is seen increasingly as an opportunity for public involvement in high-level, long-term energy planning, which serves the twin goals of ensuring that major energy decisions take public concerns into account and of contributing to public confidence in and support for utility decision-making.

IRP began in the United States and has been widely applied there, so it is not surprising that most of the IRP literature takes for granted many aspects of the electric power industry in the U.S. These characteristics include a utility industry which is predominantly privately owned[2] and which is regulated by state boards or commissions. Despite the fact that IRP was born in the American Northwest, where hydro power predominates, most of the literature devotes far more attention to the impacts and issues related to fossil fuel energy systems than hydro — probably because there are few if any major hydro projects now under consideration in the U.S.

For these and other reasons, the implementation of IRP in the Québec context raises a number of interesting questions. What would it mean for a large Crown utility like Hydro-Québec to apply IRP?

[2]With the exception of a few large federally owned hydro developments, such as the Tennessee Valley Authority and the Bonneville Power Administration.

Should it be applied only to the electric industry, or also to natural gas? What about the rest of the energy sector? Can a Crown utility be regulated in the same way that private utilities are, and should it? How can methods and procedures developed to assess the externalities of fossil fuel power plants be adapted to account for those of hydro developments, the impacts of which are more local but more complicated to assess? These and other questions must be answered before IRP structures can be developed in Québec.

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While these questions can ultimately only be answered here in Québec, it may be of interest to look at experiences elsewhere in Canada — particularly in provinces that share some of Québec's characteristics. In this sense, British Columbia is particularly pertinent. Its electric industry has striking similarities to Québec's, as we shall see in the next section, and, of all the Canadian provinces, it has gone farthest in applying integrated resource planning.

Like Québec, the B.C. electric industry is dominated by a Crown utility, but, unlike Hydro-Québec, B.C. Hydro has been fully regulated since 1980. The B.C. Utilities Commission, the regulatory body, operates at arm's length from the government, and has full regulatory control over rates and over many types of energy projects. Since 1992, the Utilities Commission has required integrated resource planning of every utility it regulates, including B.C. Hydro and several natural gas utilities.

At the same time, other bodies in British Columbia have also implemented many of the concepts normally associated with integrated resource planning, such as demand-side management, public consultation and participation in decision-making, and the explicit assessment of externalities (social costing). These bodies include the British Columbia Energy Council (an advisory body devoted to long-term planning), the Crown Corporations Secretariat (a body that oversees and provides guidance to all the Crown corporations), and of course, B.C. Hydro and the provincial energy ministry itself. Outside the energy sector, similar ideas have been central to the activities of the Commission on Resources and the Environment, an integrated land-use planning process.

This paper attempts to provide a survey of the implementation of integrated resource planning and related concepts in the energy sector in British Columbia, with a particular focus on electricity. As such, it will look at each of these bodies in turn, describing their mandates, the approaches they use, and the scope of their activities.

A. British Columbia and Québec: some comparisons

The electrical industry in British Columbia has much in common with that of Québec, both in physical terms and in institutional ones. Like Québec, B.C.'s electric supply is based on hydroelectricity, which accounts for 90% of its installed capacity (vs. 95% for Québec). Like Québec (and unlike much of the rest of North America), its periods of greatest electrical demand are in the winter, and electric space and water heating makes up a significant part of the load (though much less than in Québec). Another similarity is that most of B.C. generating stations are located far from the urban centres where most of the energy is used, making high-voltage transmission an important element of the electrical system. British Columbia's population is about half that of Québec, and its domestic electric demand is about 40% as great.

The institutional similarities begin with existence of vertically integrated, Crown utilities which are quasi-monopolies, B.C. Hydro and Hydro-Québec.[3] The two companies were created at about the same time. While Hydro-Québec was created in 1944, it was with the nationalization of Shawinigan Water and Power, Québec Power and eight other electric distribution companies and 45 electric cooperatives in 1963 that it became the Crown utility that it is today. Similarly, the B.C. Hydro and Power Authority (B.C. Hydro) was created by the nationalization of the B.C. Electric Company in 1962.

There are further parallels between the two Crown utilities. Each one embarked on massive hydroelectric development in its early years, which created considerable public controversy — the Peace and Columbia Rivers in the case of B.C. Hydro, and the Manicouagan and James Bay developments for Hydro-Québec — though Hydro-Québec also benefitted from broad “patriotic” support to a far greater extent than did B.C. Hydro. Plans to develop new hydroelectric resources have come under attack in both provinces as well (the 900-megawatt Site C on the Peace River and Alcan's Kemano Completion Project in B.C.; the 3,200 MW Great Whale project and, to a lesser extent, the Sainte-Marguerite-3 project in Québec).

Both utilities suffered through long periods of surplus supply resulting from these first developments, accompanied by corporate downsizing and internal turmoil, but, partly as a result of these developments, each utility now benefits from large blocks of relatively low-cost supply. They also have in common the distinctive operational characteristics of a hydro-based system. Unlike thermal-based systems, energy needs are a significant constraint for hydro systems — in some cases more of a constraint than capacity needs. That is, with a thermal system, planners need only worry about being able to meet peak (capacity) demand; with a hydro system, it is possible to have enough turbine capacity to meet peak demand, but not enough water in the reservoirs to meet energy needs year round.

Also, hydro systems must face considerable uncertainty in the energy output of existing resources,

[3]B.C. Hydro's monopoly is more “quasi” than Hydro-Québec's, with 11% of its sales supplied by purchases from independent producers; this share is expected to grow rapidly in the next few years. Hydro-Québec's purchases from non-utility producers now accounts for less than 1% of its total supply. While in its 1993 *Development Plan* Hydro-Québec expected about 3% of its supply to come from IPPs by the year 2000, this target has been scaled back significantly.

depending on rainfall. Since Hydro-Québec has significantly greater storage capacity in its reservoir system than does B.C. Hydro, it is protected from this variability to a greater extent. Both utilities also have substantial interconnections with their American neighbours, and long-term firm electricity exports have been the subject of ongoing controversy in both provinces.

The industrial structures of B.C. and Québec are also similar: non-ferrous metal smelting (mainly aluminum) and pulp and paper are key industries in both provinces. These two industries are both extremely energy-intensive, and as a result, electricity production is an interesting option for both of them. Alcan owns its own hydroelectric generating stations in both provinces; electricity it doesn't need is sold to the Crown utility.[4] As for the pulp and paper industry, since it requires a great deal of both heat and electricity, it has a considerable interest in cogeneration. In Québec, this interest remains largely theoretical, as only one such cogeneration plant is now in operation; while a number of additional cogeneration plants were planned for, the program has been scaled back significantly in recent years, and several signed contracts were cancelled in 1994. In B.C., annual production of cogenerated electricity in the pulp and paper industry for its own consumption had reached 2.6 TWh by 1989, and energy production from wood waste, which is now disposed of in heavily polluting "beehive burners", is regarded as a high priority.

While B.C.'s electrical industry is thus very similar to that of Québec, there are significant differences as well. B.C. is a producer of both natural gas and oil and is a neighbour (and rival) of Alberta, the centre of Canada's oil and gas industry. Partly as a result, the B.C. public is not as hostile to natural gas as a fuel as is that of Québec. Furthermore, B.C. Hydro became a subject of public controversy earlier than Hydro-Québec did. As a result, the pressures for change that are only now coming to the fore in Québec hit B.C. in the 1980s. These events are described in the next section.

Perhaps the most remarkable difference between Québec and British Columbia has to do with how energy questions are seen today by the different elements of society. In the late 1970s and the early 1980s, energy was a very divisive issue in B.C. society. Proposals to build a series of new, large hydro projects provoked angry confrontations between the environmental movement and labour, and between southern white and northern Native societies. In short, energy was a hot issue, as it is today in Québec, and for all the same reasons.

Energy is no longer a hot issue in British Columbia. B.C. Hydro is widely seen as an environmentally friendly and responsible corporation. Public involvement in energy planning takes place on an on-going basis. When energy is in the news, it is in small articles at the back of the paper, not on the front page.

This is not to say that all the problems are solved. There still are contentious issues, ranging from rates to electricity exports to the development of small, wild rivers by private producers. The

[4] In B.C., Alcan's Kemano Completion Project would have resulted in significant long-term sales to B.C. Hydro. This project and the controversy surrounding it are discussed on p. 29, below.

overall context, however, is one of peace, not of war. Somehow, British Columbia appears to have created institutions that brought the energy debate under control. How that happened, and the nature of those institutions, is the subject of this paper.

B. History

As mentioned earlier, B.C. Hydro was created in 1962 following the nationalization of the B.C. Electric Company. Until 1980, B.C. Hydro was under the direct control of the provincial legislature; its construction projects were only subject to public review insofar as they required water licenses.[5] However, this arrangement came under broad attack in the context of the Water Act hearings on the 1843 megawatt High Revelstoke Dam project on the Columbia River in 1976. In those hearings, interveners insisted on addressing issues such as project justification, energy planning, supply and demand forecasts and environmental and social impacts of the project. The official responsible for hearings, Water Comptroller Howard DeBeck, allowed these issues to be addressed, despite a lack of clear legislative authority, arguing that this was the only regulatory forum where they could be raised.[6] DeBeck issued a license to build the dam in December 1976, with a few environmental restrictions, and a coalition of environmental and recreational groups and a pulp and paper company appealed the decision. A five-member Appeal Tribunal appointed by the provincial Cabinet heard the appeal; a slightly amended license was finally issued in 1978.[7]

As a result of this controversy — in particular concerning the dam's environmental impacts and the credibility of the domestic demand forecasts on which the decision was based[8] — William Bennett's Social Credit government submitted legislation in August 1980 to reform the regulation of the province's energy industry. The new *Utilities Commission Act* incorporated many elements of the provisions of the old *Energy Act*, but included many innovative features as well.

Previously, utilities were regulated by the B.C. Energy Commission, but B.C. Hydro had been exempt from its oversight. Under the new act, B.C. Hydro was placed under the regulatory control of the new B.C. Utilities Commission. The Act also:

[5]B.C. Hydro has paid and continues to pay royalties to the provincial government for the use of the province's water. Until recently, these royalties constituted the Crown utility's only payments to the provincial government.

[6]N. Bankes, “Energy Project Review in British Columbia: A comment on the Utilities Commission Act, 1980,” *U.B.C. Law Review*, 16:1, pp. 101-113.

[7]“Energy in British Columbia — The Turning Point,” *Nature Canada* 7:1, January 1978, and Province of British Columbia, Ministry of Environment, Water Rights Branch, *Power in British Columbia: Annual Review for 1979*, p. 9.

[8]M. Jaccard, J. Nyboer and T. Makinen, “Managing Instead of Building: B.C. Hydro's Role in the 1990s,” *BC Studies*, nos. 91-92, Autumn-Winter, 1991-1992, p. 104.

- created a "single-window" review process for energy projects under the auspices of an inter-ministerial Energy Project Coordinating Committee, where project justification (including load forecasts and alternative energy sources, including conservation) and environmental concerns (including mitigation and compensation) are addressed in a single hearing process, carried out by the B.C. Utilities Commission,

- created a provincial regulatory apparatus for energy exports, to supplement the jurisdiction exercised by the National Energy Board. Exports were to be reviewed taking into account domestic energy requirements, environmental impacts, the degree to which prices reflect full long-term value, and economic advantages and disadvantages to British Columbia, including any effects on employment and income growth; and

- regulated the petroleum and natural gas industries, though these provisions were repealed in 1987.[9]

While these changes were at first severely criticized by the energy industry, environmentalists and local governments,[10] the Act has largely withstood the test of time. Representatives of the utilities, industry, environmental and other public interests and government itself today are extremely supportive of the regulatory regime created by the *Utilities Commission Act.*

It took several years before the Utilities Commission's oversight began to affect B.C. Hydro in a substantive way. As we shall see in the following brief chronology, the Utilities Commission's oversight played an important role in two key changes at B.C. Hydro: the abandonment of the Site C hydro project, and the shift in corporate philosophy to favour conservation over generation that led to the creation and active development of PowerSmart, B.C. Hydro's energy efficiency arm.

In 1981, B.C. Hydro applied to the Commission for approval to build Site C on the Peace River, downstream from the W.A.C. Bennett Dam, whose 2730 MW already supplied a considerable proportion of Hydro's generating capacity. Hearings were held before the new Utilities Commission, starting in November 1981. At the time, B.C. Hydro was forecasting 6% annual load growth, and expected to need Site C by the end of the decade.

By the next year, however, electricity sales were plummeting as the recession hit, and rates were rising. Even the 6% increase granted by the Utilities Commission, the maximum permissible under a government-imposed rate cap, was insufficient to allow the Crown utility to meet its target financial ratios. The Utilities Commission announced that in the future, it would review B.C. Hydro "for prudency of investment and efficiency of its operations."[11] The need date for Site C was put off until 1991.

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[9]A. Thompson, N. Bankes and J. Souto-Maior, *Energy Project Approval in B.C.*, Westwater Research Centre, 1981, p. 25.

[10]N. Bankes, *op. cit.*, p. 101.

[11]B.C. Hydro, *Annual Report, 1982-83,* p. 23.

In 1983, after a year of hearings, the Utilities Commission ruled that Site C was environmentally acceptable, but it "recommended delay until B.C. Hydro's forecasting methods provided firmer evidence of the dam's need."[12] Meanwhile, Hydro announced changes to its load forecasting methods and, perhaps more important, to how the forecasts were used in planning. Instead of building to meet the medium growth scenario, the utility stated that it would only schedule firm resources to meet the low end of the planning range; any load growth above that would be met by purchases or by acceleration of already-scheduled resources.[13]

The Revelstoke Dam came on line in 1984, increasing B.C. Hydro's installed capacity by 25%, but load growth in the early 80s had been so far below projections that when it did, it was in fact 100% surplus to domestic needs. "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 [in 1989 dollars], while the levelized cost of electricity from the dam [was] on the order of 4.2 cents/kWh."[14]

The changes at B.C. Hydro began with the appointment of Chester Johnson as CEO in 1984. Once it was recognized that significant capacity expansion would not be required in the foreseeable future, Johnson dramatically downsized B.C. Hydro. This began what was to become a major shift of power within the utility, where engineers gave way to managers as the dominant force within the company.

These changes accelerated with Johnson's replacement by Larry Bell in 1987. It is Bell who is widely credited with transforming B.C. Hydro. A high-level civil servant in the provincial Finance Department, Bell was named by the Social Credit government of Bill vander Zalm. His mandate was to turn B.C. Hydro into a customer-oriented business that functioned more like a private corporation than like a typical Crown corporation. Bell served as CEO of B.C. Hydro until 1990.

[12]Jaccard et al., *op. cit.*, p. 104-105.

[13]B.C. Hydro, *Annual Report 1984.*

[14]Jaccard et al., *op. cit.*, p. 104.

The Greening of B.C. Hydro

Larry Bell was clearly a pivotal figure at B.C. Hydro, according to Ken Peterson, Director of Planning under Bell and now head of Powerex, B.C. Hydro's export subsidiary. "The lesson from the Bell era is that one guy at the top can make a huge difference if he's got a vision and keeps hammering at it," he said. The flavour of Larry Bell's leadership was well captured in an admiring portrait in a B.C. business magazine shortly before he left the company:

> "The most profound change [under Bell's leadership] has been in philosophy. You could call it The Greening of Hydro. Spurred on by overly optimistic forecasts of economic growth, for decades Hydro built new dams, flooded valleys and provided British Columbia with electrical power in abundance. The very large in-house staff of skilled hydroelectric engineers, whose entire careers were devoted to the exploitation of two major rivers (the Columbia and the Peace), created an internal bias to pursue major dam projects. ...
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> "Bell says Hydro's low cost options are also those that are environmentally attractive. 'Traditionally, conservation was seen as something that you did between projects. Once you had a big project coming on line, you said "We have a surplus for a while." Quite naturally, because you bring it on in big increments and so that is not the time to promote conservation because the marginal cost of energy is literally zero.
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> "'My view of this was that you can't treat it in residual fashion. We have to re-order priorities. Conservation is the first best option, using what you have got efficiently. It enhances people's incomes, it enhances the productivity and profitability of our economy, and so that has to be a constant, not something you turn off and on with major projects. That's a major philosophical change.'"[15]

One of the problems Bell faced was a malaise within the organization, due to the massive layoffs resulting from the recession and the surpluses of the mid-80s. Total staffing dropped by half from 1981 to 1990; the engineering design department fell from 1,150 employees to 350 during the same period. One consequence was that there was a dearth of talented young people in the organization. Bell's responses included a tripling of the budget for training and apprenticeship, and engaging a consulting firm specializing in corporate self-renewal and transformation, Bob Johnson's Trendsitions Strategy Management.

Trendsitions Strategy Management is a small consulting company that has successfully catalyzed corporate transformation in a number of large firms. According to Johnson, his company was called in by Bell, who was disappointed in the lack of response within the company to the changes he had announced. "You can't change a company with posters and videos," says Johnson, who was told by many employees that "you can't get there from here."

Johnson's approach was based on working with small groups at every level of the company, starting at the top. The goal was to harness the ideas and creativity of the staff itself in order to find ways to carry out the changes articulated by top management. The first group — and Johnson insists that this is essential to the success of any corporate transformation — must be composed of the company's top management.[16] Thus, his first workshops at B.C. Hydro were with Bell and his staff, and with the 10

[15] J. Lyon, "The New Face of Power," *B.C. Business*, February 1990, p. 16.

[16] In 1992, Johnson declined an offer to work with one Hydro-Québec department

vice-presidents and their staffs. They worked their way down through the organization, training trainers along the way. By the time they finished almost four years later, he estimates that 4,500 of B.C. Hydro employees had participated directly in one of these groups. "It's a myth that people resist change," says Johnson, "they only resist change that is imposed on them. It is the individuals within the organization that create change, but they must be empowered to do so with a strong commitment from the CEO."

As might be expected, there was some resistance within the company to this "greening." Even among the vice-presidents, there were those who saw the shift of focus to demand-side as something of a "scam" — necessary to obtain government approval to go on building dams. Only after frank and in-depth discussions were these individuals persuaded that DSM was not-dressing, but was in fact the organization's best chance to continue to grow and prosper over the long term.

The clearest legacy of Bell's tenure at B.C. Hydro was the creation of Power Smart, the utility's energy efficiency department. Power Smart was formally launched in 1989, but its roots go back farther than that. While conservation was incorporated in B.C. Hydro's *Electricity Plan* as far back at 1984, it was not until the B.C. Utilities Commission directed Hydro to develop plans to implement energy conservation in 1986 that actual conservation planning began. Staff drew up a list of 35 possible programs and presented them to Bell. "We expected him to choose a few of them," said Jack Habart, until recently head of strategic planning at Power Smart. "Instead, he said, 'Do them all — tomorrow.'"[17]

Power Smart has since grown rapidly. Power Smart energy savings in B.C. last year reach almost 1.5 TWh, or 3.5% of B.C. Hydro's total sales. Its average cost to B.C. Hydro per kilowatthour saved is just 1.6 cents, compared to 3.3 cents per kWh for new short-term supply.[18] By way of comparison, Hydro-Québec's energy efficiency project has realized about 1 TWh of savings, which amounts to 0.6% of its much larger sales volume.

A Power Smart subisidary was also created in 1990 to market the Power Smart name and programs outside of B.C. Power Smart Inc. became an independent company in 1994, and is now jointly owned by seven utilities, including B.C. Hydro, Ontario Hydro and Hydro-Québec. Through B.C. Hydro International, it is marketing demand-side programs to several countries in Europe and Asia.

Since Bell's resignation in 1990, there have been several changes in leadership at B.C. Hydro, due in part to the change in government in 1991. Marc Eliesen, then head of Ontario Hydro, was named to the job by the new NDP government, but he didn't last long. "He irritated everyone — at the Ministry, the Utilities Commission, the Energy Council and at Hydro's Board," said one observer. "I've never seen anyone burn out his welcome that fast."

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because, he says, unless the top management is actively involved, the process is likely to be unsuccessful.

[17]Quoted in *Power Smart Five-Year Review* (1994), p. 3.

[18]*Ibid.*, p. 5.

John P. Sheehan was named interim CEO when Eliesen left in April 1994, and was appointed CEO in November. He has focussed his attention on the movement toward deregulation in the U.S., and has recently announced a major restructuring with this in mind. At the heart of the new structure is the separation of generation from transmission/distribution (T&D) as separate and potentially independent business units. While the short-term effects may not be dramatic — apart from involving several hundred layoffs — the restructuring is widely seen as a step that is intended to permit the company to respond more quickly to possible regulatory developments that may let Canadian utilities compete more directly in American markets.[19]

The election of an NDP government in 1991 led to important changes in the B.C. energy picture. The new government took three actions, the results of which will be discussed at length in this report:

- it named Mark Jaccard, a young professor of environmental and resource economics from Simon Fraser University who had played a leading role in B.C.'s energy debate for several years past, to head the B.C. Utilities Commission. Under Jaccard's energetic leadership, the Utilities Commission has come to play a central role in B.C. energy planning. Since 1992, it has required integrated resource planning of all utilities under its purview, and has played a key role in a broad range of energy-related issues. The structure and activities of the Utilities Commission will be discussed in detail in Chapter II of this report.

- it moved quickly to pass legislation creating a British Columbia Energy Council, an advisory body to report back to the government on a long-term sustainable energy policy, following broad public consultations. While originally conceived as a permanent body, the Energy Council's mandate was terminated as of November 1994. Its processes and its final report, *Planning Today for Tomorrow's Energy*, are discussed in detail in Chapter III.

- it created the Crown Corporations Secretariat (CCS), a small, governmental body whose mandate is to achieve efficiencies and synergies among all the British Columbia Crown corporations, particularly with respect to capital spending. In the energy sector, the CCS acts in effect as the government liaison with B.C. Hydro. Its role, and the relationship between its oversight of B.C. Hydro and that of the B.C. Utilities Commission, will be discussed below in Chapter IV.

Each of these bodies affects, directly or indirectly, the choice of energy resources, both supply- and demand-side. With respect to supply-side resources (both generation and transmission), B.C. is now in the process of revising its approach to environment assessment for energy projects, in a way which establishes close ties with the integrated resource planning process. This new environmental assessment process will be described in Chapter V.

Finally, Chapters VI through VIII will present discussion and analysis of the effectiveness of B.C.'s existing regulatory and planning structures.

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[19] More discussion of this reorganization is found on p. 31, below.

II. BC UTILITIES COMMISSION

A. Structure and mandate

The British Columbia Utilities Commission bears the primary responsibility for energy regulation in British Columbia. It is an independent regulatory agency of the provincial government, set up under the *Utilities Commission Act.* Since 1980, the Utilities Commission has regulated virtually all gas and electric utilities in B.C.[20] Its primary responsibility is "to ensure that the rates charged for energy are fair, just and reasonable, and that utility operations provide safe, adequate and secure service to their customers."[21] The mechanism for carrying out this mandate is the review of rate applications from each utility, in which it determines which expenditures may be recovered from ratepayers, approves rate designs and sets actual rates. Since 1992, as a means of judging the prudency of investments and hence the justification of rates, the Utilities Commission has required the utilities it regulates to carry out least-cost integrated resource planning. This aspect of its activities will be discussed in detail below.

The British Columbia Utilities Commission actually has three distinct roles. First and foremost, it is a regulator. Second, it reviews applications for the authorizations required for different categories of energy projects.[22] It also is responsible for the granting of energy removal certificates (ERCs), required for the export of energy resources from the province. Finally, it holds hearings and makes recommendation on specific energy-related issues referred to it for this purpose by the Cabinet.

The Commission consists of a chairperson, a deputy chairperson, six part-time commissioners, a professional staff of 16, and an administrative and support staff of ten. The Commissioners are named by the Energy Minister; the staff chosen by the Commissioners. Total staffing has varied from a maximum of 33 in 1985 to 24 in 1991 (see Figure 1). Apart from its administrative services and a secretariat that handles formal communications with the government and with the public, the staff is composed of engineers, financial analysts, economists and conservation specialists broken down into three groups: electrical, petroleum/gas, and "strategic services." This last group handles

[20]The Utilities Commission is responsible for the regulation of 19 utilities in British Columbia. These include one Crown corporation (B.C. Hydro), 5 investor-owned electric utilities, 6 municipally owned electric utilities, 6 investor-owned natural gas utilities, and one investor-owned steam heat utility. The only utility it does not regulate in Westcoast Energy, a natural gas transmission company that falls under the exclusive jurisdiction of the National Energy Board.

[21]*British Columbia Utilities Commission Annual Report, 1993*, p. i. This and other publications of the B.C. Utilities Commission can be obtained by writing to R. Pellatt, Secretary, B.C. Utilities Commission, 900 Howe Street, Sixth Floor, Box 250, Vancouver, B.C. V6Z 2N3.

[22]For smaller projects, the Commission directly issues the necessary authorizations, referred to as Certificates of Public Convenience and Necessity. For larger projects, it makes recommendations to Cabinet, which makes the final decision on issuing Energy Project Certificates. This structure will change slightly in accordance with the new Environmental Assessment Act, discussed in Chapter VI, below.

special projects such as the development of the IRP Guidelines and the upcoming hearings on competitive markets.

The Commission holds public hearings in response to applications from utilities (for project approval or for rates) or to requests from Cabinet, or in some cases on its own initiative. In 1993, the Commission held 12 distinct hearings lasting a total of 80 days. As well, 154 specific orders of different types were issued, and 7 Certificates of Public Convenience and Necessity (project approval certificates).

The Commission is funded through a levy on the sales of all regulated utilities; its total budget requires legislative approval. Until 1994, this rate was set at about 0.1% of gross energy sales.[23] The amount levied in 1993 was just over $3 million.

Under the *Utilities Commission Act*, the Commission has considerable independence and powers:

- It is free to determine its own staffing requirements and to choose its own staff, who are not considered civil servants (Section 8);
- it may initiate inquiries or hearings on any matter within its jurisdiction, and thus is not limited to responding to applications or complaints (Section 97);
- it has all the powers of the provincial courts to require testimony and access to documents. As well, it can issue mandatory or restraining orders or order payment of penalties with enforcement powers equivalent to those of the provincial courts. Penalties can be levied against utilities, their officers and employees or other individuals who fail to obey Commission orders, up to $10,000 a day (Sections 88, 89 and 124),
- its decisions can be appealed to the provincial Court of Appeal (Section 115);
- under amendments to the *Act* adopted in 1993, it can pay all or part of the costs of participants in its proceedings, or can order one party to pay the costs of another.

Applications filed by utilities are reviewed by Commission staff, who issue requests for additional information until they are satisfied that the application is reasonably complete. All documentation is sent to registered interveners and is available for consultation by the interested public.

The Utilities Commission's hearing procedures are relatively formal, though not as formal as court proceedings. Witnesses testify under oath for the utility and for each registered intervener that

[23]It is now levied on the basis of quantities of energy sold, rather than on revenues.

wishes to present testimony. Each witness may prefile written testimony and present a short introductory statement. Witnesses are then cross-examined, first by the Commission counsel, and then by counsel for the utility and for each registered intervener. When individuals participate as interveners, they usually are not represented by counsel, but have the right to cross-examine all witnesses themselves.[24] The Commissioners may also intervene with questions at any time.

Regulation of rates

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The primary role of the Utilities Commission is to set rates for the utilities it regulates that are fair, just and reasonable. In doing so, it reviews and makes judgements as to the prudency of all expenditures that the utility wishes to recover through rates. The total amount of money to be recovered by a utility from ratepayers in a given year is referred to as the "revenue requirement." The revenue requirement includes all expenditures which are judged by the regulator to be prudent (including financing, amortization and depreciation of prudent capital expenditures), as well as profits or earnings to the shareholders (the investors or, in the case of a Crown utility, the Government), the amount of which is also set by the regulator at a level commensurate with the risks to which they are exposed.[25]

The revenue requirement includes both current expenditures for operations, maintenance and administration (OMA) and financing costs on previous capital expenditures. OMA expenditures are reviewed by the Utilities Commission in considerable detail. If the Commission is not convinced of their prudency, it can:

- request more detailed accounting of the expenditures, and explanations for them,
- disallow the expenditures, resulting in reduced profits, below the established return on equity, or
- allow the expenditures, but warn the utility that, unless the problems noted are resolved, it may disallow similar expenditures in subsequent years.

[24]Some interveners have expressed concern that this process gives too much space to individuals, using up expensive hearing time in ways which do not contribute much to the outcome.

[25]This profit is usually described as a percentage return on equity (ROE). However, in the case of Crown utilities, where the figure used to describe the Government's "equity" is open to interpretation, other measures of appropriate earnings can be used. See the discussion of Special Direction No. 8, below.

Theoretical Underpinnings of Regulation

Regulation in the electric industry was traditionally based largely on the "natural monopoly" characteristics of the electric industry and the fact that it engenders significant levels of externalities.[26]

Natural monopolies

The concept of recovery of prudent expenditures (plus a guaranteed return on equity) on which the regulatory regime is based, flows directly from the notion of a regulated natural monopoly. A natural monopoly exists when "the lowest possible production costs can be achieved only if there is [only] one firm in the market."[27] In exchange for permitting a firm to reap the benefits of such a monopoly, and to prevent it from extracting excessive profits from a captive public, many governments have chosen to place such a firm under regulatory controls.

A regulatory system for a natural monopoly is in essence a mechanism to apportion costs appropriately between the utility's owners and its customers. For an investor-owned utility, this distinction is clear: the former are the shareholders, who may or may not live in the company's service area, while the latter are the electric consumers served by the utility, the vast majority of whom are not shareholders. Since most utilities are monopolies, in that their customers have no alternative energy supplier with whom they can deal, the shareholder's power to set unfairly high rates is unrestrained by market forces. As long as that monopoly exists, it must therefore be *regulated* to protect the interests of ratepayers.[28]

For a Crown utility, however, the situation is less clear, since most ratepayers are also citizens, and thus indirectly "shareholders". Nevertheless, the distinction is still an important one. If one assumes that all profits from the Crown utility are returned to the provincial government as dividends and thus serve to reduce provincial taxes, an imaginary citizen/ratepayer might be indifferent to the level of electric rates, assuming that he both consumes an average amount of electricity and pays an average amount of taxes. In practice, of course, none of these conditions are true. Most utility profits are reinvested; while they may thus help to reduce electric rates in the future, they do not directly reduce the tax burden. More important, even if they are returned to the government, consultations carried out by the B.C. Energy Council clearly show that most people are not convinced that the money is well spent: they suspect that it is either wasted by utility management or by government.

In practice, therefore, the situation of a Crown utility is not that different after all from that of a

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[26]These concepts, along with a third "public good" rationale, which is less relevant to our discussion here, are explored in much greater detail in Mark Jaccard, "Canadian Electricity Markets and the Future Role of Government," *Energy Studies Review*, 6:103-126 (1994).

[27]*Ibid.*, p. 3.

[28]This monopoly situation has been called into question in the debate over retail wheeling. Ongoing changes both in the structure of the North American electricity market may be leading to changes in the extent to which electric service is a natural monopoly, and hence in the kind of regulation that is appropriate to it. These issues are now being addressed in Utilities Commission hearings on the structure of B.C.'s electric market, under a special mandate from the Energy Minister. See discussion on page 29, below.

privately owned utility: ratepayers have a strong interest in seeing that rate increases are kept to a minimum, while utility management and shareholders (the provincial government) have a competing interest in seeing utility profits maximized. The role of the regulator is precisely to adjudicate between these competing interests, based on the principal that rates should be fair, just and reasonable, and that the utility should only be able to recover prudent expenditures through rates.

Externalities

A second justification for regulation, and one which is rising in prominence even as the "natural monopoly" rationale recedes, is to respond to the growing recognition that significant externalities are associated with electric generation and transmission. Externalities are costs or benefits borne by persons who are not party to the transaction. Common negative externalities associated with the electric industry include urban citizens affected by air pollution from power plants, or Natives whose hunting territories or fishing grounds are lost to hydroelectric development. There are positive externalities as well, though care must be taken not to confound them with mere shifts of economic activity.

If electricity is treated strictly as a commodity with its price determined purely by negotiations between buyers and sellers, these externalities will have no effect on the amounts sold or on their price. From an economist's point of view, the virtue of a free market is that it automatically determines the level of production and consumption that maximizes overall wellbeing; however, if externalities are not accounted for, it will allow more electricity will be produced and used than is economically desirable.

Most regulatory systems attempt to account for externalities in the choice of new resources. Theoretically, they should also be taken into account in making dispatching decisions (deciding which resources of the available resources to use) and in setting electric rates. Some regulators are experimenting with the former; the latter option is discussed below (p. 63).

Revenue requirement regulation can be both retrospective and prospective: a utility comes before its regulator seeking the right to recover through rates monies which have already been spent, or for approval of a budget for future expenditures. Such approval constitutes the "regulatory compact" — if a budget has been approved in advance, the regulator is normally bound to consider the expenditure "prudent" when it is submitted for recovery, later on.

Capital expenditures pose a problem to the regulatory system, since they are only submitted for recovery through rates once the capital project is completed. Given the long lead-times of many capital projects, this may mean that billions of dollars have been spent before the regulator has a chance to evaluate the prudency of the project. While it is not impossible for a regulatory commission to judge a capital project imprudent and disallow recovery of its costs, this would normally be considered a violation of the regulatory compact. However, under exceptional circumstances, expenditures can be disallowed as imprudent. Such disallowance protects the ratepayers, but it can result in significant losses to shareholders; if the disallowances are large enough, they can even threaten the financial stability of the utility.

This has been a major issue in those American jurisdictions which invested heavily in nuclear energy. The nuclear industry encountered enormous cost overruns during the 1980s, and in some cases, utilities commissions refused to allow recovery of these costs in rates, resulting in large losses to shareholders. The losses became catastrophic in cases where the plants were never completed.

In the most famous case, that of the Washington Public Power Supply System (WPPSS, known as "Whoops"), the disallowance of expenditures for uncompleted nuclear plants resulted in a "death spiral": drastic rate increases, leading to loss of customers as industries relocated to avoid the high rates, leading to even more surplus capacity and thus even higher rates, leading ultimately to bankruptcy.

The possibility that major capital expenditures will be disallowed thus creates a very undesirable situation, from all points of view. It is bad for the shareholders, in that it greatly increases their risk, and it is bad for ratepayers, in that it increases the return on equity that shareholders must be permitted in order to ensure continued investment in the utility. It also decreases the financial stability of the utility, thereby increasing its general borrowing costs; since these costs *are* recoverable, it again results in higher rates. Finally, and perhaps most importantly, it denies the regulator an opportunity to consider the prudency of capital expenditures before they are made, and thus undermines the fundamental philosophy of regulation of a natural monopoly, i.e. the right of the public to ensure that the utility's actions are in the public interest.

This need to find a way to fully review capital investment decisions before they are made has been one of the primary driving forces behind integrated resource planning (IRP). Capital costs typically comprise a large percentage of total utility expenses, especially for utilities that rely heavily on capital-intensive technologies such as nuclear power and hydroelectricity. While the *Utilities Act*, under the authority of which the Commission operates, does not specifically mention IRP, it does "outline the Commission's responsibility to make certain that utilities undertake comprehensive planning to ensure that generation, transmission and distribution assets are installed by utilities so that the customer needs are fully satisfied and that rates are fully justified."[29] It is on this basis that the Utilities Commission has developed its IRP process, to ensure that capital expenditures, and hence rates, are fully justified.

An analysis of the B.C. Utilities Commission's approach to IRP is presented in the next section.

In conjunction with its regulatory role, the Utilities Commission can also hold generic hearings on energy-related issues when it sees fit. Thus, hearings were held in 1994 on the appropriate level of return on equity for several smaller utilities, and generic hearings are expected in the coming year on planning processes which involve more than one "fuel" (e.g. both electricity and natural gas). These hearings will be used to determine the basis on which fuel-switching measures by gas and electric utilities will be assessed.

Regulation of exports

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Under the *Utilities Commission Act*, exports of all types of energy resources, including electricity, are also regulated by the Utilities Commission. Export of any energy good, including both natural gas and electricity, requires an *energy removal certificate* (ERC) from the Utilities Commission. For significant

[29] B. C. Utilities Commission, *In the Matter of British Columbia Hydro and Power Authority, 1994/95 Revenue Requirements Application: Decision*, November 24, 1994, p. 64.

exports, the Commission normally holds hearings prior to issuing the ERC.

Electricity exports have been a controversial issue in B.C., due to concerns that British Columbians will suffer environmental impacts relating to electricity production for export which exceed any benefits they may obtain. The debate about electricity exports has gone through several stages. In 1992, the Utilities Commission held hearings on a request for an ERC from B.C. Hydro. The application requested permission to export 2,300 megawatts to the United States and 1,200 MW to Alberta, 6 TWh a year of firm energy, and 25 TWh/yr of interruptible energy.

The Commission recommended granting the certificate, but only under the condition that the energy exported be short-term surplus; in other words, surplus energy from facilities which were built to serve domestic customers. As a result, the Commission recommended that "three years should be the maximum duration for firm energy sales contracts allowable as short-term exports." The Commission decision was made dated June 1992.

It was clear from these hearings that there was still significant public opposition to exports, particularly to long-term exports of firm electricity. To try to resolve these conflicts and to help arrive at a provincial policy regarding long-term exports, in July 1992 the Energy Minister asked the newly created B.C. Energy Council to consult the public and produce a recommendation concerning such exports. Specifically, it was to evaluate the net costs and benefits to British Columbians of exports of sufficient duration and magnitude to require the construction of new generation or transmission facilities.

This review was completed in 1993. It recommended permitted long-term firm exports, but only under the condition that:

- no new large hydroelectric projects be built or advanced for export,

- the period of ERCs be limited to 10 years or to the period for which B.C. Hydro had sufficient supply existing or under construction for domestic needs, unless it could be shown that the export would result in a net benefit for the province, taking all social and environmental costs into account,

- a portion of resulting government revenues would be used to provide benefits to areas that would be impacted by the generation and transmission facilities, and

- export policy be reviewed when ERCs for an aggregate of 4 TWh/yr of long-term firm energy had been issued.[30]

[30]British Columbia Energy Council, *Long-Term Firm Electricity Export Review: Final Report*, April 7, 1993, 115 pp.

Based largely on this report, the government issued a policy on electricity exports in 1993.[31] This policy adhered closely to the recommendations of the Energy Council. However, it extended the maximum term for ERCs to 20 years, and did not include an aggregate annual limit for an automatic policy review.

Special hearings

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Finally, under the *Utilities Act*, the Minister can ask the Utilities Commission to hold public hearings on an energy-related matter and submit a recommendation to the Minister. One such mandate was given to the Commission in 1993 concerning the Kemano Completion Project, which has been the subject of heated controversy in British Columbia for many years. Another has just been made concerning retail competition.

a. The Kemano Completion Project

The first phase of the Kemano project was completed in the early 1950s; it is a hydroelectric generating station owned by Alcan to produce energy for its aluminum smelting operations at Kitimat. It involves the diversion of water from the Nechako River, an eastward-flowing tributary of the Fraser River, through a mountain tunnel into the Kemano River, which flows westward to the Pacific Ocean.

The agreement with the B.C. government on which the first phase of the Kemano project was based also foresaw a second phase, which would involve a second mountain tunnel and the diversion of even more of the Nechako's water. Under the agreement, Alcan would get a permanent water license at 1950 rates for the second phase, but only if it is completed before the turn of the century.

In 1979, Alcan announced that the Kemano Completion Project would go ahead. The company had no plans to build new smelters to use the additional power; instead, it contracted with B.C. Hydro to purchase the additional energy.

The project is controversial for several reasons: on account of its impact on the Native people of the region and on the Nechako River salmon populations (and those of the Fraser, downstream), because the energy is not needed for aluminum production as originally intended, but will be sold to B.C. Hydro instead,[32] and because the terms of the original agreement were so favourable to Alcan. There was also a significant jurisdictional dispute between B.C. and the federal government

[31] Province of British Columbia, Ministry of Energy, Mines and Petroleum Resources, *Electricity Export Policy: Long-Term Firm Exports*, July 12, 1993.

[32] While B.C. Hydro maintains that the energy would be used for meeting domestic needs, it is widely believed that it would instead be exported.

regarding the environmental assessment of the project. These were resolved, in a manner of speaking, in a 1987 out-of-court settlement, whereby the federal government reversed its earlier position and agreed to Alcan's terms.

In 1988, Alcan began construction. In 1990, an environmental group and a Native group filed a court challenge, seeking an environmental review. The Federal Cabinet then declared the project exempt from the EARP process, but a federal court ruled that the exemption was invalid. Alcan then suspended construction, pending the resolution of all outstanding environmental assessment issues. The Federal Court of Appeal reversed the earlier judgement, eliminating the need for a federal review, but the provincial review process still applies.

Thus, under a special mandate from the Minister, the B.C. Utilities Commission was charged to assess the Kemano Completion Project. The terms of reference limited the review to social and environmental impacts within the two watersheds directly affected. Public hearings lasted almost a year. The report was delivered to government in December 1994; in January 1995, it was made public. At the same time, the B.C. government announced that it would not allow the project to go forward. Most observers expect Alcan to seek compensation for its losses; a long legal battle is almost certain to ensue.

b. Retail competition and "unbundling"

A similar mandate has recently been issued to the Utilities Commission, under which it is to hold hearings in the spring of 1995 into possible structural changes in the B.C. electric industry, specifically with respect to retail competition (also known as "retail wheeling") and the "unbundling" of electric services. These two questions are the subject of hot debates across North America, as the electric industry is undergoing a profound restructuring.

Wheeling refers simply to a utility's making its transmission facilities available to others for transactions in which it is not involved. Thus, *wholesale* wheeling is the sale of energy from a generating company to a utility, using the transmission facilities of another utility. Wholesale wheeling allows electric distribution companies to purchase electricity from geographically distant producers, in effect introducing competition between different electricity suppliers at the level of *generation*. Different generating companies can then compete on a level playing field to sell large blocks of energy to distribution utilities, regardless of their geographic location. Such arrangements are increasingly common in North America; the American *Energy Policy Act* of 1992 mandated wholesale wheeling throughout the United States, and structures have been created to make that possible. It should be noted that, under this arrangement, the monopoly position of a utility — its right and obligation to serve all clients within its geographical service area — is not affected.

Retail wheeling, on the other hand, would allow *individual consumers* to purchase electricity from geographically distant producers, in effect introducing competition between different electricity suppliers at the level of *distribution*. This is analogous to the current situation in long-distance telephone service, where individual consumers can choose among several suppliers of long-distance services. Retail wheeling does not now exist anywhere in North America, though several American states are actively exploring the possibility of implementing it. Such an arrangement would break the monopoly relationship between a utility and its customers.

Unbundling refers to the breaking up of traditional electrical service into its components and marketing them separately. Thus, in addition to the firm power traditionally sold to its clients, a utility might offer unbundled "products" such as interruptible power (with no guarantee of constant service), backup power (for clients who produce their own electricity), energy storage, etc.

In the United States, rapid changes are underway in the structure of the electric industry. A vigorous debate is now underway in many jurisdictions across the U.S. whether or not to implement retail wheeling, and if so, how. Support for it is strongest among industrial consumers, who see it as a way to reduce their costs by being able to purchase directly from low-cost suppliers (usually fueled by natural gas), instead of from their local utilities. Utility rates are higher for a number of reasons, including expensive existing supply, the obligation to maintain capacity margins and to serve unprofitable customers, and, in some cases, considerable DSM expenditures.

Many utilities are opposed to retail wheeling. They fear they will be unable to compete with IPPs due to the high cost of power from their more expensive existing installations (especially nuclear), resulting in *stranded investments*[33], and due to their responsibilities for system reliability. Most environmental and public interest groups are also opposed, because breaking the monopoly relationship between a utility and its customers makes the concept of utility-sponsored DSM programs extremely problematic. Also, such an arrangement would tend to reduce regulatory oversight of the industry, with resource-planning decisions based purely on market forces, which do not take into account their total costs to society (the externality rationale for regulation); Finally, they fear that, as "captive customers" of the utilities, residential consumers will be stuck with large rate increases as utilities lose their more profitable industrial clients.

While there do not appear to be significant pressures from within B.C. or other Canadian provinces to permit retail wheeling, there is great interest on the part of Canadian utilities in selling into the markets this movement is creating in the United States. It is not at all clear what changes might be necessary *within* Canadian provinces to permit access to these markets. It has been suggested American electricity pools might not allow Canadian utilities to compete in their markets unless reciprocal access is provided for American producers to Canadian markets.[34] While such reciprocal access would be disastrous for high-

[33]John P. Sheehan, President of B.C. Hydro, made these comments about stranded investments at the Canadian Energy Council Forum in Montreal in October 1994: "Stranded investments, which arise when utilities lose major customers but remain stuck with their investment in plant that was developed in part to serve those customers, pose some difficult questions. Who should pay, or how should the burden of paying for unused generating capacity be shared? The problem becomes worse the longer the amortization period for the plant in question, another reason that megaprojects are out of favor today."

[34]Richard Drouin, CEO of Hydro-Québec, recently stated before the Commission de l'Économie et du travail of the Assemblée Nationale that he expected Hydro-Québec to face retail competition in Québec within four

cost Canadian producers like Ontario Hydro, many observers feel that, due to its low costs, B.C. has little to fear from American competition. However, the uncertainty associated with the *possibility* of losing significant amount of load to foreign competition could wreak havoc with utility forecasting and planning. This will undoubtedly be one of the issues addressed in the Commission hearings.

A recent reorganization at B.C. Hydro may be a foreshadowing of things to come. In late 1994, B.C. Hydro carried out an internal reorganization which in effect separated generation from transmission/distribution (T&D) as separate business units. Setting up T&D as a separate unit is hoped to facilitate participation in the Regional Transmission Groups now being set up in the U.S.; it would also make it easier to permit open access, either on a wholesale or even retail basis, should reciprocity be required.

There are those who see this restructuring as just a beginning; the next step would be to actually spin them off into separate companies, perhaps privatizing some elements. Here, we enter into the world of speculation, as a multitude of different schemes are being discussed. In almost all of them, the distribution company — that which sells electricity directly to consumers — would remain a fully regulated monopoly, in either public or private hands. High-voltage transmission, however, would almost certainly remain publicly owned. According to some models, it would remain fused with the distribution company; in others, it would be a free-standing entity.

Some observers feel that such a structure could theoretically allow the fundamental goals of IRP and regulation to be met, while at the same time capturing the benefits of increased competition.[35] However, to do so would require some kind of "dedicated surcharges," like those proposed by the B.C. Energy Council (see p. 63). Furthermore, the levels of these surcharges would have to be quite substantial, and would have to be modulated to reflect the different social costs attributable to each different source of energy. Others, however, consider such an arrangement politically impossible to achieve, and thus conclude that deregulation even of this limited type remains counter to the goal of sustainability and to society's long-term interests.
The Commission's mandate is to canvass the public and interested groups on the appropriateness of retail competition for B.C., taking into account its implications for integrated resource planning, including DSM and accounting for environmental externalities. Given the high degree of sophistication with which these issues are already addressed by the Commission, the B.C. utilities, and the groups which intervene regularly before them, these hearings promise to be of great interest, not only for British Columbia, but for other regions of Canada as well.

B. Integrated Resource Planning

While other organizations discussed in this report also use concepts related to integrated resource

to five years.

[35]See for instance Jaccard, “Changing Canadian Electricity Markets and the Future Role of Government,” *op. cit.*, pp. 124-125.

planning, it is the B.C. Utilities Commission that actually oversees the application of IRP by energy utilities. This is a relatively recent development, which began with the issuance by the Commission of draft integrated resource planning guidelines in August 1992, shortly after Mark Jaccard was named to chair the Commission. After a period for comment from the utilities and the general public, final Guidelines were issued in February 1993.

These Guidelines are notable for their brevity and generality. While they clearly identify the major steps required, they refrain from specifying the methodologies or modalities to be used to accomplish them (e.g. monetization of externalities). In this way, they differ significantly from the requirements in most of the American states, where the public utilities commission typically specifies in considerable detail the precise information required and how it is to be presented.

According to Commission staff, this choice was deliberate; it was meant to promote flexibility, in two distinct ways. On the one hand, it was meant to allow the same set of guidelines to apply to the 19 diverse utilities regulated by the Commission. These include electric utilities (ranging from vertically integrated utilities to municipal distribution utilities) as well as natural gas and propane pipeline and distribution companies. They range in size from B.C. Hydro (a Crown corporation with annual sales of electricity of over $2 billion) to Northland Utilities, a gas distribution utility with annual sales of under $6 million.

A second but equally important reason for this strategic choice in the Guidelines was the desire to let methods and standards evolve over time. While rigid specifications might lead to more complete submissions in the early years, the authors of the Guidelines felt that this benefit was outweighed by the danger that, in later years, such rigidity would become a millstone, preventing adaptation to changing circumstances. This reflects a basic principle underlying the Commission's approach to regulation: to allow the Commission's policies to develop gradually, as “case-law,” rather than to “legislate” sweeping policies in advance. In keeping with this approach, the Commission insists that utilities take cognizance of all decisions issued, and assume that similar requirements will be applied to them when appropriate.[36]

Steps in preparing an IRP

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The Guidelines outline seven steps in preparing an integrated resource plan, which are described briefly here. In the next section, we shall look at them in more detail as they have been implemented by two electric utilities and a natural gas utility.

- Identification of objectives

[36] B.C. Utilities Commission, *In the Matter of British Columbia Hydro and Power Authority*, *op. cit.*, p. 58.

These can include but are not limited to reliability of service, economic efficiency, equal consideration of DSM and supply-side resources, minimization risk and consideration of social and environmental impacts. In its decisions, the Commission has insisted that objectives be stated explicitly, and that planning choices be based directly on the stated objectives.

- Development of a range of demand forecasts

These are “gross” forecasts, i.e. not taking into account the impacts of DSM programs. There should be a range of forecasts to reflect uncertainty about the future, and the forecast should be structured and disaggregated in such a way that savings from particular DSM programs can be allocated to specific end-uses in the demand forecast.

- Identification of supply and demand resources

These should include all feasible resources, i.e., all indivisible investments or actions the utility could take to modify the supply or the demand of energy and/or capacity.

- Characterizing supply and demand resources

Each of the resources identified should be measured against a consistent set of qualitative or quantitative attributes, which reflect the objectives established above. This multi-attribute analysis may include costs to the utility, to the customer and to third parties, including rate impacts, social and environmental impacts, risks and lost opportunities (those which, “if not exploited promptly, are lost irretrievably or rendered much more costly to achieve”). For some resources, costs can be represented as supply curves, which show the unit cost associated with different magnitudes of the resource.

- Development of multiple integrated resource portfolios

For each of the gross demand forecasts, several plausible resource portfolios should be developed, including both supply and demand resources.

- Evaluation and selection of resource portfolios

This involves the comparison of the portfolios developed in the previous step on an attribute-by-attribute basis, for each of the gross demand forecasts, based on a multi-attribute trade-off process involving the public. Several iterations may be necessary. The result — the integrated resource plan — is the selection of a set of resource portfolios, one for each demand forecast.

- Action plan

The action plan defines the actions necessary in the short term (about four years) to implement the integrated resource plan (IRP)[37] selected for the demand forecast judged most likely. It must also indicate how the utility

[37]Unfortunately, the acronym "IRP" is used to represent both "integrated resource planning" and "integrated

will process and respond to information during that period that might show divergences in demand growth above or below this "medium" forecast.

Process

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The Commission Guidelines clearly require that the public be involved throughout the IRP process, though they do not specify how that should be done. Suggestions include holding information meetings, workshops and stakeholder collaboratives, and preparing issue papers distributed to the public for response.

Stakeholder Collaboratives and Consultative Committees

Stakeholder collaboratives and consultative committees are mechanisms used increasingly widely to give the interested public a voice in important decisions. They consist of groups of 10 to 30 individuals, representing a broad range of interests and points of view, who work together over a period of time attempting to find solutions that are acceptable to all. The term "stakeholder" refers to all those groups and individuals in society who hold a "stake" which is potentially affected by the decisions under consideration. For utility planning, the stakeholder group is typically very broad, including business, industry, farming, environmental and consumer groups, First Nations and other public interest groups. A distinction can be made between a true *collaborative*, where decision-making power is shared among all participants, and a *consultative committee.* Consultative committees retain full control over their own process, like a collaborative; however, their role is advisory and not decisional.

Under the Utilities Commission's IRP Guidelines, there is a positive obligation on the part of the utilities to permit the public to be involved throughout the IRP process, and thus to make its decisions in the full knowledge of the public's informed recommendations. However, utilities have to take full legal responsibility for their plans, and the Utilities Commission has rule that they cannot delegate this power. The Commission's recent decisions, discussed below, make clear that it strongly favours the use of stakeholder consultative committees.

A widely admired true collaborative was sponsored by B.C. Hydro to evaluate the technical and cost-effective potential for energy conservation and efficiency.[38] The collaborative committee included 13 members, representing 34 organizations, including residential, commercial, industrial, Native, environmental and local government interests, as well as B.C. Hydro. Representatives from the Energy Ministry and from the Utilities Commission also participated as observers. Decision-making was by

resource *plan."*

[38]Electricity Conservation Potential Review Project, 1988-2010, *Achievable Conservation Potential in British Columbia Through Technological and Operating Change: Final Report* and *Conservation Potential Through Lifestyle Change: Final Report*, July 1994. The review was coordinated by Nancy J. Cooley of Colley/Olsen, Inc. and Janet Gavinchuk of B.C. Hydro, with the assistance of the Synergic Resources Corporation (SRC). It is available from B.C. Hydro, or from SRC (report no. 7933-R5).

consensus, and included "approving the terms of reference for the review, selecting consultants, determining all key assumptions and parameters to be used by the consultants, and reviewing and approving all reports."[39]

The Guidelines also require that Utilities Commission staff be given opportunities to review and comment on the IRP at various stages of its preparation. Plans are to be filed with the Commission for review every two years. The Commission is to provide written commentary on the plans, and its review may involve public input.

C. Recent decisions

The best way to understand the application of IRP by the Utilities Commission is through its decisions. We will look in detail at three recent decisions, concerning the IRPs of West Kootenay Power (a small investor-owned electric utility), and of the Crown electric utility, B.C. Hydro. The IRP of B.C. Gas, a large gas distribution utility, will also be briefly discussed.

West Kootenay Power

West Kootenay Power (WKP) is small investor-owned utility serving about 120,000 customers in the southern interior of B.C., including the rapidly growing Okanagan Valley region. It owns four hydroelectric plants on the Kootenay River, with a combined capacity of 205 MW. The remainder of its needs are met a complicated combination of purchase contracts from Cominco (a lead-zinc smelting company) and B.C. Hydro.

a. West Kootenay Power's IRP

The draft integrated resource plan filed in 1993 by WKP was its first, and it was the first draft IRP to be examined by the Utilities Commission following its February 1993 Guidelines. A concise document, it consisted of 104 pages, plus 136 pages of technical appendices. In structure, it adheres closely to the Guidelines. Introductory materials are followed by chapters on power requirements, supply-side resources and DSM resources, social costing (externalities), portfolio analysis, and finally an action plan.

Supply-side resources

The analysis of supply-side resources in the draft IRP looked at two types of resources:

- resources that could be developed by WKP either alone or in joint ventures: these included both site-specific projects and generic resources. The first category included four new hydro projects, two hydro expansion

[39] *Ibid.*, p. 6.

projects, two small (5 MW) wood waste plants, combined-cycle gas turbines, turbine upgrades, T&D efficiency improvements, non-firm purchases and energy from American dams on the Columbia River that may be returned to Canada upon expiration of the Columbia River Treaty (the so-called "Downstream Benefits"). The resources treated on a generic basis included coal, wind, solar, fuel cells, biomass, municipal solid waste, geothermal and nuclear power; and

- purchase offers in response to a request for proposals (RFP): the utility had 36 offers, including 10 small hydro projects, 8 wood waste thermal projects, 8 gas turbines (both single and combined cycle), 2 waste-to-energy projects, 2 cogeneration projects, one wind-hydro combination and 5 sales offers from other utilities.

Demand-side resources

The range of DSM options examined included:

- increased investment in the seven DSM programs now underway at WKP,
- new residential programs, including comprehensive or selective building envelope retrofit rebates, new construction efficiency rebates, free showerheads upon request, refrigerator buyback program, compact fluorescent lights, and a fuel switching program (electric baseboard to natural gas),
- new commercial programs, including programs for efficient lighting, heating, ventilation and air conditioning,
- new industrial programs, including motors, pumps and fans, an industrial audit program, and a special set of programs for Cominco, and
- a peak shaving program including heat storage systems, programs to shift water pump and water heating loads off-peak and demand limiters.

These options were screened for financial impacts, using a software package distributed by the Electric Power Research Institute (EPRI), with rebates calculated to yield a 2-year payback period for participants. They were evaluated based on standard DSM evaluation tests such as the total resource cost, ratepayer impact and utility perspective tests, taking into account cross-effects. All but seven of the 32 programs evaluated past the TRC test. The successful programs were combined into a single package, and then compared with the supply-side resources.

Rate considerations such as rate design, differential rates for interruptible power and mechanisms to decouple profits from sales were also considered.

Social costing

Social costing is the term most commonly used in British Columbia for the integration of externalities. That is, the "social cost" is defined to be the total cost to society, taking into account direct financial costs, financial costs to third parties (including governments), environmental and social impacts, regional development benefits, etc.

WKP's analysis of social costs was based on the multiple accounts approach developed by the Crown Corporations Secretariat (see below, p. 68). The main accounts used were:

- financial perspective, including net present value of revenue requirements, capital needs and rate impacts,
- environmental perspective, including assessment of air emissions, land and water use, noise and waste disposal impacts,
- societal perspective, including assessment of local economic impacts, and
- energy security perspective, including assessment of reliability impacts, portfolio flexibility, and portfolio risks.

Monetary values were used for some non-financial impacts, using values from the Bonneville Power Administration or the Northwest Power Planning Council. Other impacts were quantified, but not monetized. A weighting system was used in order to be able to compare impacts between the different accounts, and values for each one were “normalized” to a scale of 1 to 3.

Public involvement

In order to determine the relative values of the various attributes, a stakeholder committee was set up, with representatives from a broad range of community interests. The group, which met some seven times, was composed of representatives of diverse interests within the utility's service area, and were chosen by invitation of the utility.

Screening

The various resources were ranked according to their financial benefit/cost ratios, and also according to their performance with respect to a weighted basket of the four main accounts. Three different weighting schemes were used:

- WKP's preferred weighting, where financial impacts were given a weight of 70%, environmental impacts were given a weight of 15%, social impacts 5% and energy security issues 10%,
- one where all accounts were treated equally, and
- an intermediate approach recommended by the stakeholder committee, where the financial account was weighted at 50%, environmental and social impacts at 20% each, and energy security at 10%.

The draft IRP suggests that the stakeholder group did not come to a clear consensus on the weighting of specific attributes. However, it notes that, for the most part, the ranking of resources was highly insensitive to the precise weightings chosen.

A multi-attribute trade-off analysis was also carried out (see box), exploring the trade-offs between and within the different accounts. However, not much detail is provided in the draft IRP concerning this analysis.

Multi-Attribute Trade-off Analysis[40]

Multi-attribute trade-off analysis is a technique used that is gaining increasing acceptance in B.C. and elsewhere for making choices that have many and varied repercussions. "The goal is to make it clear how much it 'costs' in terms of one attribute (including, but not limited to, money) to gain a given benefit, or to avoid a given cost, in terms of another. Ultimately, the purpose is to find trade-offs where accepting a limited deterioration in one attribute will permit a large improvement in another. ...

"Traditional least cost planning is focused on a single criterion — monetary value. It is intended to quantify the risk of alternative courses of action and thereby to help decision makers choose a course of action that maximizes the expectation of profit.

"Multiattribute decision analysis begins with the identification of the most important attributes and, for each one, the metric that best measures performance. In the case of environmental attributes the metrics are usually either physical measures like tons, acres, gallons, etc., or subjective measures such as a range from 'very high impact' down to 'no impact'. Analysts then measure the performance of each alternative on each attribute.

"In order to be able to rank the alternatives and determine which has the greatest total utility, one must first have determined the relative importance of each attribute. In situations where there is a clearly defined group of decision makers, this is a matter of determining their value systems. But this can be very difficult in complex issues like utility planning that affect many different sectors of society, all of which are involved in the decision-making process, and which may have very different degrees of influence. ...

"In this type of analysis, the different alternatives are compared, two or more attributes at a time. The purpose is to identify situations where environmental impacts could be significantly reduced with little increase in cost, or where there are similar advantageous trade-offs between two potential impacts. To achieve additional improvements in one attribute would then result in significant deterioration in the other. ...

"Unlike traditional decision analysis, this approach delays inclusion of value judgments until after the trade-off analysis. Using this technique, decision makers must still make trade-off between attributes, but they do not have to formally describe their values, as they do in other decision analysis approaches. While people often disagree on the preferred alternatives, this analysis helped to focus the debate on those alternatives which are most desirable with respect to many attributes, including but not limited to cost."

[40]Excerpted from Litchfield, Hemmingway and Raphals, *Integrated Resource Planning and the Great Whale Public Review* (Great Whale Public Review Support Office), pp. 73-79.

Portfolio analysis

Six resource portfolios were compared, each one emphasizing a different strategy (e.g., one that minimizes financial costs, two based on hydro expansions, one relying solely on purchases, one relying solely on thermal resources, and one including the mix of resources favoured by the stakeholder committee). On the basis of the preliminary screening, certain resources were identified as extremely desirable with respect to cost, environmental impacts, flexibility and risk. WKP considered that these should be all be acquired even under the low load growth scenario, and so they were included in all but the purchase portfolio.

The six portfolios were then evaluated under the four accounts. A sensitivity analysis was also carried out, comparing them under a variety of scenarios that could pose significant challenges to the utility, including high and low load growth, high and low gas price escalation, loss of wholesale customers due to wheeling, and high and low capital costs. Each portfolio was evaluated against each scenario, according to net present value of revenue requirements.

Preferred resource strategy

WKP's preferred strategy is not the “Financial” portfolio, which ranked first in the sensitivity analysis under all scenarios, but the “Waneta” portfolio, which includes a joint venture with B.C. Hydro to increase capacity at the existing Waneta hydro plant by 390 MW. The explanation given is that this is a “lost opportunity” resource; if WKP does not pursue it now, it may lose the opportunity to participate in the redevelopment of this site.

b. The Utilities Commission decision

The Utilities Commission decision is very positive about the draft IRP, and applauds WKP for its efforts. However, it suggests the following improvements:

Public participation

The Commission found that the consultative committee should be given greater independent control over its process, and should have an independent facilitator. Thus, it should function more like a collaborative. However, its decisions cannot be binding on utility management. “Ultimately, the utility management and the Commission have decision-making responsibility for determining the prudency of the utility's IRP and the Action Plan contained therein. Neither management nor the Commission can avoid their responsibilities via a collaborative process.”[41] It also accepted

[41]B.C. Utility Commission, *In the matter of Applications by West Kootenay Power Ltd, 1994/95 Revenue Requirements, Rate Design and Integrated Resource Plan: Decision*, June 17, 1994, p. 5.

interveners' arguments that environmental and other key interests were insufficiently represented on the committee.

Demand-side resources

The Commission suggested that DSM resources should be disaggregated into smaller sets of measures, making it possible to explore the extent to which management and the consultative committee would choose to "include DSM projects that involve the trade-off of higher financial costs (hence higher rates) against non-monetized gains in the other accounts."[42]

Social costing

Several interveners objected to the methodology used by WKP for weighting and aggregating the scores of resources in the various accounts. The Commission agreed that there are problems, and asked WKP to seek to improve the methodology in its next submission.

Portfolio analysis

In the hearing, WKP defended its preference for the Waneta portfolio even though its was outperformed by the Financial portfolio, arguing that the "lost opportunity" aspects of Waneta and other attributes favourable to it were not included in the analysis. However, the Commission had serious reservations about WKP's treatment of Waneta as a lost opportunity resource. The Commission defines a lost opportunity resource as one "which will be lost to the whole of society if it is not realized at a specific time." WKP did not argue that Waneta would be lost *to society* if it was not built immediately, but only that it might be lost to WKP. This use of the concept "in a competitive sense" was troubling to the Commission, "because it could be used to justify preemptive investments in a competitive but rising costs market."[43]

WKP explained the fact that its preferred portfolio was not the one selected by its own trade-off process by arguing that the methodology chosen by the utility did not in fact fully incorporate all the Company's concerns. The Commission was careful to point out that it was not insisting that "the preferred resource portfolio need be the mechanistic outcome of the resource evaluation and account weighting exercise." But it did insist that "deviations from the outcome of the multi-attribute trade-off process must be clearly explained and defended."[44]

c. Conclusion

[42]*Ibid.*, p. 7.

[43]*Ibid.*, p. 8.

[44]*Ibid.*, p. 11.

Despite its flaws, the WKP exercise is seen by the Utilities Commission staff and by key interveners as a success, and as evidence that the IRP process can work, at reasonable cost, even for a small, rural utility.

2. B.C. Gas

The most recent hearings of B.C. Gas before the Utilities Commission were divided into three phases. The first phase dealt with rates and revenue requirements exclusively, and will not be discussed here. The second dealt primarily with a proposed mechanism to provide stabilization of rates with respect to variations in the weather, and with “decoupling” proposals; the third phase dealt with the company's IRP.

a. Rate stabilization and decoupling

It is widely recognized that one of the primary obstacles to demand-side measures is the simple fact that utilities make money on energy they sell, and not on energy they don't sell. “Decoupling” is the name given to a variety of mechanisms, several of which are now in use in various parts of the U.S., meant to “decouple” a utility's profits from its gross energy sales.

Usually these mechanisms involve somehow establishing how much energy a utility would “normally” sell, and what its profits would be; in the event that it sells less energy due to successful demand-side programs, its revenue requirement (and hence its rates) would be allowed to increase in order to provide it that same level of profits, despite its lower sales. Thus, to the extent that a utility is decoupled, it is indifferent as to whether or not its sales increase; this is widely believed to be a prerequisite to a successful demand-side program.

The previous year, B.C. Gas had requested approval for a weather stabilization-adjustment mechanism, which would have shielded the utility from revenue fluctuations resulting from changing weather conditions — in effect, a partial decoupling. In response, the Utilities Commission had instructed B.C. Gas to submit a proposal for full decoupling in its 1994 application.

The utility did not do so, but instead filed an analysis of full decoupling, finding that it was inappropriate for B.C. Gas at this time. Several intervenors objected to this failure to comply with a clear Commission directive; the B.C. Energy Coalition argued that “a simple decoupling mechanism is the most practical approach for beginning the alignment of shareholder and customer interests.”[45]

In its decision, the Commission agreed with the utility's assessment that “full decoupling of sales from profits is not an *essential* precndition for ensuring that the utility pursues only those sales that are in the

[45]B.C. Utilities Commission, *In the Matter of B.C. Gas Utility Ltd., 1994/95 Revenue Requirements Application, Phase 2: Decision,* August 4, 1994, p. 2.

best interests of customers and society."[46] However, it pointed out that one of its objectives was "to minimize the need for detailed regulatory control ... by ensuring that, wherever possible, the incentives of regulation are aligned with the public interest." It agreed with the Energy Coalition that decoupling the distribution utilities' sales from short-run profits would have this result. However, it rejected the Energy Coalition's proposed solution, favouring instead the one proposed by R. Brian Wallace, speaking for the industrial consumers. This solution would have the effect of eliminating the profit incentive to pursue short-run sales during the winter (peak) period, "thereby eliminating the potential conflict with the demand-side pursuit of economically efficient energy services."[47] At the same time, the new mechanism would not affect summer sales, since the Commission found that increased off-peak sales increased the efficiency of the entire system, leading to benefits for all classes of customers.[48] This solution appears to be acceptable to the utility, as well as to the interveners. A B.C. Gas spokesman described it as "complicated, but workable." Jaccard, however, characterizes it as one of the simplest decoupling mechanisms in North America, both with respect to implementation and monitoring.

b. Integrated Resource Plan

Despite the important differences between the electric and gas industries — the most important being that gas utilities handle transmission and distribution only, while production is unregulated and in the hands of other companies — the experience of the B.C. Utilities Commission demonstrates that the same integrated resource planning framework can be applied to both, with only minor adjustments.

The Utilities Commission in general reacted very positively to the IRP filed by B.C. Gas. However, a number of points were criticized. The key issues addressed in the IRP phase of the hearings included IRP objectives, the multi-attribute trade-off analysis (MATA) process, demand-side management, resource portfolios and fuel switching. Other issues which will not be addressed here included long-term load forecasts, avoided costs, and the main extension policy (distribution system).

IRP Objectives

While the Commission accepts the fundamental objectives posed by B.C. Gas for its IRP, objections were raised regarding two points. First, the issue of the relationship between the IRP objectives and the Corporate Strategic Plan. B.C. Gas argued that the two documents were only loosely connected, in that the Strategic Plan described what the Company's role should be in certain activities, while the IRP described goals for the indistry and the province as a whole. Thus, while the two documents are complementary, neither is dependent on the other. On the other hand, the B.C. Energy Coalition

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[46]*Ibid.*, p. 4.

[47]*Ibid.*

[48]The greenhouse-gas implications of off-peak load building are not addressed in the decision.

argued that the IRP should serve as a guide for corporate planning.

The Commission disagreed with the utility, stating that "the IRP is does not merely describe what the Company is encouraging for the industry and the province." The Commission believes that the Corporate Plan must be consistent with the IRP; otherwise, "there will be a serious risk of corporate actions frustrating effective implementation of IRP activities."[49]

The multi-attribute trade-off analysis (MATA) process

The MATA methodology used by B.C. Gas was strongly criticized by the Energy Coalition and Consumers' Association of Canada (B.C. Branch). Carol Reardon, legal counsel for the Energy Coalition, argued that it was inadequate to permit participants' values to be clearly translated into tradeoffs between attributes.

More specifically, she argued that, "The use of the median values to derive the coefficients for the MATA calculations was fundamentally contrary to consensus decision making. The Keeney/MacDaniels process is simply not designed to encourage agreement among the stakeholders."[50] Furthermore, she noted that, "The authors of the questionnaire took no steps to ensure that the answers they got were mutually consistent, despite the existence of a large body of learning showing that these sorts of questionnaires can produce distorted, misleading and inconsistent results."[51]

The Commission acknowledged these criticisms, but stopped short of condemning the approach taken. Rather, it urged the utility to continue to refine its efforts to incorporate monetized environmental impact measurements, and to collaborate with other utilities in solving these problems.

Demand-side management

Generally speaking, the gas industry has been far more reticient about DSM than the electric industry. Gas executives often argue that, since they are transmission/distribution companies and not producers, their potential cost savings resulting from conservation are considerably lower than those of vertically integrated electric utilities.

In this light, it is somewhat remarkable that the B.C. Gas IRP proposed a series of nine conservation

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[49]B.C. Utilities Commission, *In the Matter of BC Gas Utility Ltd., 1994/95 Revenue Requirements Application, Phase 3: Decision*, August 12, 1994, p. 4.

[50]Carol Reardon, *Written Submission on Behalf of the B.C. Energy Coalition, In the Matter of An Application by B.C. Gas Utility Ltd., 1994/95 Revenue Requirements Phase 3 and Integrated Resource Plan*, July 1994, p. 8.

[51]*Ibid.*, p. 12.

and load management DSM programs to reduce growth in energy sales by 24% and to reduce growth in peak demand by 55% by the year 2000. The Commission commended B.C. Gas "on the breadth and depth of its proposed conservation and peak shaving programs, and concludes that a reasonable balance has been achieved amongst the key criteria of market penetration, cost effectiveness and equity."[52] Nevertheless, and despite the fact that no interveners objected to any of the programs, the Commission took a critical look at each one. It rejected two proposals outright; for most of the others, it insisted that the utility proceed cautiously, starting with pilot projects, before a commitment is made to major incentive investments. Most of these programs were later approved, after modifications.

Resource portfolios

The long-term load forecasts developed by B.C. Gas project a growth in energy demand of 27% to 40% over the next 20 years, and a growth in peak (daily) demand of 43% to 59%. (The Commission expressed reservations about the forecasting methodologies used, and required the utility to continue to explore alternative models.) Based on these figures, the utility looked at ten different supply options. These options, which included peaking/seasonal contracts, underground storage and various liquified natural gas (LNG) or propane/air possibilities, were combined with the retained DSM options and grouped into seven portfolios, which were then compared with a base-case status quo alternative. This alternative assumed that all additional load would be supplied by new gas purchase contracts and that the existing storage facilities would remain available.

The results, in the view of both the utility and the interveners, clearly showed that new LNG plants would play an important role in a least-cost plan. This general orientation was accepted by the Commission. However, it noted that, on the one hand, the cost assumptions used regarding the LNG plant may have been overly optimistic, while on the other hand, potential benefits such as reliability, security of supply and operating flexibility were not factored in.[53] Thus, the Commission required the utility to proceed with additional uncertainty analysis in its ongoing analysis of the LNG option.

In an earlier decision, the Utilities Commission had denied approval for a deferral account to begin feasibility studies for such a plant, "on the basis that B.C. Gas had not established in an IRP framework that a new LNG plant was necessary.[54]" Given the acquiescence of all the interveners, the Commission agreed to open the deferral account for a first phase feasibility study. However, it stipulated that, before additional expenditures would be approved, the utility would have to perform the uncertainty analyses described above. Also, driven by the concern that it might prove impossible to find an acceptable site for such a plant, the Commission required the utility to provide ongoing information on siting as the studies proceed.

[52]*Ibid.*, p. 21.

[53]*Ibid.*, p. 13.

[54]*Ibid.*

Fuel switching

Among its DSM programs, B.C. Gas included several "fuel switching" programs to encourage clients to switch from electric heating to natural gas. The Commission found that the underlying issues had not been sufficiently addressed to justify such measures; it rejected all these programs, pending generic hearings or other processes to be held in 1995 on the assessment of fuel-switching initiatives (see p. 26).

c. Discussion

Despite the widespread feeling in the natural gas industry that IRP runs counter to its fundamental interests, B.C. Gas appears to have embraced this approach to planning. Philip Murray, who directed the IRP process for the utility, described the process as constructive and useful. He was critical of the common approach of using public participation as a public-relations tool — "It is supposed to be getting input from the stakeholders before you make decisions," he said.

Indeed, of the three examples examined here, it appears that it is in the B.C. Gas IRP that public input had the most direct impact — and, curiously enough, for a supply-side option, the liquified natural gas (LNG) plant. The reason is that storage facilities make it possible to respond to peak demand without building new pipelines; coupled with an aggressive demand-side program, it appeared (at this preliminary stage) to be the least-cost solution, taking both economic impacts and externalities into account. Interestingly, this option had not aroused much interest in government circles; it was stakeholder support that was decisive in convincing the Utilities Commission.

3. B.C. Hydro

While B.C. Hydro is just one of the 13 utilities regulated by the B.C. Utilities Commission, it is by far the largest, and the only Crown corporation. As such, it poses special problems.

The relationship between B.C. Hydro and the Utilities Commission has not been an easy one. This is attributed by observers to the circumstances surrounding the creation of the Utilities Commission in 1980. As described earlier, a desire to "bring Hydro under control" was an important element leading to the *Utilities Commission Act* of 1980, and it is thus perhaps understandable that the utility has not been an enthusiastic supporter of the Commission. Widespread scepticism regarding the technical competence of the Commission during its early years did not help matters. However, the changes at the Commission in the last few years seem to have won the respect of B.C. Hydro management. B.C. Hydro spokespersons now express grudging support for the Commission and the importance of its auditing and oversight role.

Tensions remain, however, particularly concerning IRP. While B.C. Hydro is widely seen as a leader in the application of integrated resource planning in Canada, it has been severely criticized by the Commission for ignoring the Commission's Guidelines. B.C. Hydro, for its part, has maintained that the Utilities Commission does not have statutory authority to require it to submit IRP's for Commission approval.[55]

Notwithstanding this legal objection, B.C. Hydro has not refused to carry out the integrated resource planning process mandated by the Commission in its Guidelines. In 1993, B.C. Hydro thus submitted its long-term *Electricity Plan* and supporting documents as an IRP.

The Commission engaged a well-known consulting firm, Barakat & Chamberlin to determine whether or not these documents were consistent with the elements of IRP, as set out in the Commission's Guidelines. The consultants' report found that the *Electricity Plan* appeared to be reasonably consistent with general IRP principles, but noted several areas where it failed to meet the requirements of the Guidelines. Specifically, it found that:

- the utility's objectives in the IRP process were not clearly identified,

- the information provided concerning the load forecast was not sufficient to be able to judge its validity, and the range of forecasts was too small to make it possible to test the robustness of resource acquisition decisions,[56]

- detailed information was provided on the preferred resource portfolio, but it was not clear what resources had been considered but rejected, or why the preferred portfolio is preferred,

- it was not clear from the *Plan* whether external stakeholders were involved throughout the planning process, as required by the Guidelines, or only towards the end of the process when certain details had to be resolved.

For the most part, B.C. Hydro witnesses acknowledged these criticisms. The Commission's decision directed B.C. Hydro "to make those changes which are necessary to convert the current *Electricity Plan* in to a full Integrated Resource Plan."[57] In particular, it needed "a clearer statement of objectives, increased documentation of load forecasting methodologies and a broader range of forecasts, identification of all resources considered in the planning process, not just those retained in the preferred portfolio, more information concerning each resource and the process used to choose among them, and increased public

[55]B.C. Utilities Commission, *In the Matter of B.C. Hydro, 1994/95 Revenue Requirements Application: Decision*, December 7, 1993. This argument was rejected by the Commission, but the decision was appealed by B.C. Hydro. The matter is still before the courts.

[56]"A proposed resource portfolio is considered robust if it has the flexibility to meet energy service requirements not only under the scenario considered most likely, but also for a broad range of possible futures, with minimal economic or environmental penalties." Litchfield, Hemmingway and Raphals, *IRP and the Great Whale Public Review, op. cit.*, p. 10.

[57]*Ibid.*, p. 42.

participation at an earlier stage of the planning process."[58] Furthermore, B.C. Hydro was reminded that "the IRP provides the focal point for justification of future capital projects which the Utility may wish to undertake. As a result, the IRP should contain sufficient information to allow non-utility parties to understand the Utility's objectives and to follow the Utility's reasoning in arriving at its decisions. ... It is expected that the Utility's IRP will generally conform with the Commission's Guidelines and, where not in conformity, the Utility will explain and justify the reasons for deviation."[59]

This set the stage for the 1994/95 hearings, which took place in September 1994. The decision, released in late November,[60] is even tougher than the previous one. While lauding much of the work done by the Crown utility, it insists, in very direct language, that the requirements of the Guidelines be met. Furthermore, the Commission found little evidence that its capital budgets were actually based on the IRP process.[61]

The decision addresses each element of the IRP Guidelines in turn.

Objectives

The *Electricity Plan* set out six long-range planning objectives, and five specific objectives. In addition, B.C. Hydro has five corporate objectives, established by the Board of Directors without input from senior management. However, the relationships among these various sets of goals were not clear, nor was their role in determining the preferred resource portfolio. Furthermore, "the Commission is concerned that the lack of public involvement undermines the credibility of the chosen IRP objectives."[62] The Commission directed B.C. Hydro to review the objectives with its new IRP consultative committee, and to ensure that all future capital plans are based on the IRP and its action plan.

Development of a range of demand forecasts

The Commission found that the utility's methodologies are consistent with the IRP Guidelines, but that insufficient use was made of scenario analysis to evaluate the risks faced by the utility.

Identification of supply and demand resources

The Commission was satisfied that all feasible supply and demand resources were identified with

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[58] Ibid., p. 30.

[59] *Ibid.*, p. 42.

[60] B. C. Utilities Commission, *In the Matter of British Columbia Hydro and Power Authority, 1994/95 Revenue Requirements Application: Decision*, November 24, 1994.

[61] *Ibid.*, p. 24.

[62] *Ibid.*, p. 33.

respect to generation. However, given the size of the anticipated capital spending on transmission and distribution, it found that more work was necessary to identify scenarios that used other options to meet these needs, taking into account the risk of stranded investment resulting from new technologies of conservation and distributed generation.[63]

This risk was detailed in a study prepared by B.C. Hydro, tabled at the hearings at the request of an intervener.[64] The study looks at the impacts on the utility's financial performance that would result from losing part of its expected customer load due to a gradual increase in distributed generation starting early in the next century. The results are dramatic: even a minor penetration of these technologies would lead to very substantial energy surpluses and a drop in return on equity from 15% to 6.4%; moderate penetration would result in very substantial losses.

While the study is very preliminary, including many simplifying assumptions, the conclusion is clear: increasing uncertainties in load projections due to the eventual penetration of distributed generation technologies pose a major threat to utility finances. The same reasoning evidently also applies to load lost through retail wheeling.

Characterizing supply and demand resources

The factors taken into account by B.C. Hydro in evaluating resource options are described in its Resource Acquisition Policy, one of the documents that make up its IRP. The Policy was developed without extensive public involvement, but is presented by B.C. Hydro as consistent with both the multiple accounts evaluation guidelines of the CCS and the Commission's IRP Guidelines.

The Commission expressed dissatisfaction with the lack of public involvement in the multiple accounts evaluation (MAE), and also with the selection of resources to which this approach was applied. B.C. Hydro limited its MAE to potential generating resources which passed an informal screening and which it had an interest in developing in the near future. A number of issues were therefore eliminated from the process, including generating resources excluded for one reason or another by the utility, “committed” resources (those for which a formal decision had been made to acquire them), transmission projects and the dispatch of existing resources.

The Commission thus called for a more systematic assessment, using a public process to assess the trade-offs between a wider range of resources for a broader and more consistent list of attributes. In particular, the Commission called for a more explicit treatment of uncertainty, and directed B.C. Hydro to review the contracts with Alcan related to the Kemano Completion Project as part of its

[63] Distributed generation refers to the situation where an energy consumer generates his own power and thereby buys less from the utility. It discussed on page 60, below.

[64] B.C. Hydro, *Potential for Stranded Investments: Financial Consequences to B.C. Hydro of New Generation Technologies*, February 1994 (30 pp.).

next IRP, comparing the economic and social costs of implementing the contract with the costs of not implementing it.[65] It also required that purchases from independent power producers (IPPs) be evaluated on an equal footing with in-house resources.

Development, evaluation and selection of resource portfolios

According to the Commission Guidelines, utilities are to develop several plausible resource portfolios to meet each of their load forecast, and to compare them on an attribute-by-attribute basis, according to the stated objectives of the IRP. In its Plan, B.C. Hydro presented a single preferred portfolio for all levels of demand, saying it would "address the risk of supply and demand imbalance through adjustments to project schedules, power purchase and sales opportunities, thermal generation levels and storage in multi-year reservoirs." The Commission pointed out this problem, noting that "each of these [actions] has vastly different environmental and social implications."[66]

As concerns the selection of resources, the *Plan* states that reliability of supply is the primary acquisition criterion, but that "resources will be acquired in advance of reliability requirements if there is an opportunity to reduce the expected social cost of meeting future requirements."[67] This policy is applied to "lost opportunity resources" as well as to those which are so economically attractive to the utility that the benefits of their purchase would outweigh any risk of oversupply. B.C. Hydro places this limit at 2.5¢/kWh, which thus "constitutes a standing offer at which to purchase electricity. ... [This price is] below its short-run cost of new electricity supply and would generally be less than the price at which the Utility could expect to resell the energy in the non-firm export market."[68]

While it did not directly criticize any of the specific policies presented in the *Electricity Plan*, the Commission was extremely critical of the process by which these decisions were arrived at.

> "To date, B.C. Hydro has used multiple account evaluation simply as a means of structuring information for use in an apparently unstructured decision-making process. While this ... may prove useful to decision-makers, it does not allow for public scrutiny of the decision. As a result, the decision-making process continues to be opaque rather than transparent. The Commission believes an explicit decision-making process is necessary if the public is to be assured that all interests have been fairly represented and fairly considered."[69]

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[65]See note 71, below.

[66]B. C. Utilities Commission, *In the Matter of British Columbia Hydro and Power Authority, 1994/95 Revenue Requirements Application: Decision, op. cit.*, p. 48.

[67]*Ibid.*, p. 49.

[68]*Ibid.*

[69]*Ibid.*, p. 51.

Public participation

The decision is scathing in its assessment of B.C. Hydro's public participation process:

> "B.C. Hydro has not followed the spirit of the Commission's Guidelines with respect to public involvement [and] has not followed the specific directions given to it in the last Decision with respect to public involvement ... Although the Utility has put into place a number of processes which deal with the public, it appears that the majority of these processes are more in the nature of education programs which provide information to the public but do not involve the public in decision-making.
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> "The Commission finds such an approach unacceptable for two reasons. First, decisions concerning resource acquisition require not only the consideration of the direct costs and benefits attached to a particular project but also the indirect, and frequently intangible, costs and benefits. Determination of the appropriate trade-offs between resources requires that the values the public attaches to these costs and benefits must be determined and factored into the decision in an explicit and transparent way. The Commission has made it clear that such values are best determined through the direct participation of representative interest groups.
>
> "Exclusive reliance on the B.C. Hydro staff, managers and Board of Directors for resource selection is also unacceptable for another reason. A closed, in-house process has the appearance of, and real potential for, bias in decision making that favours the interests of the bureaucracy within the Utility. ...
>
> "This failure to understand or, if understood, failure to comply with, the Commission's Guidelines and directives with respect to public participation forces the Commission to issue new directions with respect to this issue that are unprecedented in their detail. The Commission regrets that such action is necessary since it is wary about entering areas that have traditionally been the prerogative of management; however, B.C. Hydro's failure to respond to the Commission's December 7, 1993 directions leaves it no choice."[70]

The Commission thus instructs B.C. Hydro to set up an IRP consultative committee, building on the membership of the prior DSM collaborative (see page 34), and including representatives of IPPs. As noted earlier, it is understood that, while the committee should have independent control over its own process, B.C. Hydro retains all decision-making power with respect to the IRP.
Precise instructions are given as to the issues that should be addressed by this committee, ranging from the IRP objectives, load forecasting methodology, scenario development, DSM programs, policy for addressing greenhouse-gas concerns, a multi-attribute trade-off analysis along the lines of that conducted by West Kootenay Power, comparison on a equal footing of all resources under consideration, and the risks and benefits associated with B.C. Hydro's treatment of purchases from IPPs and from Alcan (including from the Kemano Completion Project).[71]

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[70] p. 57.

[71] This instruction that the consultative committee include the purchase of energy from the Kemano Completion Project in its deliberations was of considerable significance. Until then, B.C. Hydro had treated this purchase as a "committed resource," and therefore it has not been included among the options under review in the IRP. Public opposition to the Kemano project was strong, and, while there clearly would have been substantial penalties if B.C. Hydro had withdrawn from its contract with Alcan, B.C. Hydro and its consultative committee would have had to weigh those costs against the environmental and social benefits that may have resulted from cancellation. Now that the government has cancelled the project, these questions are of course moot.

Adequacy of documentation

Several interveners insisted that B.C. Hydro's *Electricity Plan* does not constitute an IRP and should not be accepted as such. The Industrials Customers noted that “there is no clear ranking of supply options, no clear portfolio alternatives, [and] no visible and identifiable risk analysis.”[72] The Energy Coalition described the documents as “a cosmetic improvement to the most serious problem ... : the lack of transparency of the resource planning process and the barrier it creates for public accountability. Even after two weeks of hearing, the trade-off process that went into these documents is still as mysterious as the Sphinx.”[73]

Discussion

As the other two examples we have looked at demonstrate, it would be a mistake to see the testy relations between B.C. Hydro and the Utilities Commission as typical of the regulatory process in B.C. Rather, it should probably be seen as symptomatic of the shifting power relationship between a large Crown utility and what it sees — at least at some level — as an “upstart” regulator. At the smaller utilities, like West Kootenary Power or B.C. Gas, the Commission's authority is not questioned: it is seen as having a clear mandate to oversee their affairs, including their long-term planning, and they are making their best effort to meet the Commission's requirements.

At B.C. Hydro, the situation is very different. Despite its stated support for the IRP process mandated by the Commission Guidelines, it seems clear that, at its highest levels, Hydro has not really accepted the right of the Commission to instruct it as to what kind of decision-making processes to follow, or what kind of documents to produce. This is clear in the company's position, mentioned earlier, that, under the *Utilities Commission Act*, the Commission does not have authority to approve or disapprove a utility's IRP, but only to require that one be submitted. This argument was rejected by the Commission in its 1993 hearings, but B.C. Hydro is seeking leave to appeal this decision.

As to the future development of this relationship, one can only wait and see. Most observers believe that B.C. Hydro will follow the Commission's instructions, and thus accept its role in planning, albeit grudgingly. Nevertheless, this experience probably indicates that the imposition of regulation onto a large, hitherto independent Crown utility is not a simple or painless process.

[72] *Ibid.*, p. 62.

[73] *Ibid.*

III. BRITISH COLUMBIA ENERGY COUNCIL

A. Mandate

The British Columbia Energy Council was created in June 1992 by provincial legislation, the *Energy Council Act*, following a recommendation from the British Columbia Round Table on the Environment and the Economy. The Round Table was set up in 1990 "to produce a sustainable development strategy for British Columbia and to propose better ways of resolving conflicts over the environment and the economy and to increase public understanding of sustainable development issues."[74] It was modelled on the federal Round Table set up by Council of Resource and Environment Ministers, and was composed of stakeholders from all sectors of society.

The purpose of the Energy Council was to advise the Minister of Energy, Mines and Petroleum Resources on energy matters, and in particular to facilitate comprehensive energy planning in British Columbia. Specifically, it was to prepare recommendations for a sustainable energy strategy at two-year intervals, and to examine specific energy issues as directed by the Minister.

The planning focus of the B.C. Energy Council is much broader than that of the B.C. Utilities Commission. The reflections of the B.C. Energy Council focussed largely on the ways in which future energy needs are determined by the actions of people or bodies that are not concerned or even aware of the impacts of their actions of energy consumption.

Public involvement and participation were central to the Council's mandate. The Council's terms of reference required that it "assure the opportunity for public involvement ... and weigh economic, environmental, social and regional considerations in keeping with a sustainable energy strategy for British Columbia."[75]

The Council consisted of one full-time chair, six part-time councillors, and a small staff. Its budget, funded directly by a levy on energy utilities based on their total energy sales, was just under $1.5 million per year.

During its 2½ years of existence, the Council produced 36 documents, including two major reports. The first, in response to a mandate from the Minister, was on long-term electricity exports (*Final Report on Long Term Electricity Exports)*. The second, its final energy strategy *(Planning Today for Tomorrow's Energy: An Energy Strategy for British Columbia)* issued just before the Council closed down in November 1994.[76]

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[74]British Columbia Energy Council, *Planning Today for Tomorrow's Energy*, p. 4.

[75]*Ibid.*, p. i.

[76]These and other publications of the B.C. Energy Council are available from the B.C. Ministry of Energy, Mines and Petroleum Resource, Communications and Public Affairs, 8th Floor — 1810 Blanshard Street, Victoria, B.C. V8V 1X4. Telephone: (604) 952-0152, Fax (604) 952-0151.

While, under the *Energy Council Act*, the Energy Council was to have been a permanent body which would produce an Energy Plan at two-year intervals, the B.C. government decided in March 1994 to terminate its mandate by the end of November 1994. (The reasons for this decision are discussed at the end of this chapter.) The Council's sustainable energy strategy, entitled *Planning Today for Tomorrow's Energy*, is thus its first and last full report.

In addition to its mandate to prepare an energy strategy, the Council was also to carry out public reviews of specific energy-related issues upon the request of the Minister. The Council was given such a mandate soon after it was created: to produce recommendations concerning long-term firm exports of electricity. It carried out this mandate before beginning work on the energy strategy, and submitted its report in April 1993.

According to its chair, Richard Gathercole, the structure and mandate of the were determined after looking closely at similar institutions in the United States, particularly the California Energy Commission and the Northwest Power Planning Council. However, he pointed out that it is difficult for the NPPC to address certain issues because its mandate is limited to electricity planning. The Energy Council sought to take broader aim, including other fuels (like natural gas) and other energy sectors (like transportation) within its purview. “If you look at the California Energy Commission and what it does, it is very much a creature of the 1970s,” he said, “and the Northwest Power Planning Council is a creature of the 80s. We sought to create an institution that would meet the demands of the 90s.”

B. Process

The Energy Council took its mandate to involve the public in its deliberations seriously. For the energy strategy, written or verbal submissions were made by some 40 individuals and about 120 groups, including environmental and consumer groups, business and professional associations, municipal and regional governments, utilities and First Nations. Meetings and discussions were held in 37 communities around B.C.

The Council's approach to consultation was based on the following principles:

- involving people in all parts of the province,
- removing financial barriers to participation,
- listening with an open mind,
- making sure that time frames for participation were reasonable,

- being sensitive to land claims and cultural issues in dealing with First Nations people;
- giving participants a variety of ways of providing input,
- providing clear and easily understandable materials,
- designing the public process in consultation with those involved, and
- providing feedback to participants as to the Council's reactions to what it has heard.[77]

Throughout this process, the Council maintained an unprecedented degree of openness in its proceedings. All of its meetings were open to the public, and everything was on-the-record. "There has been a long history of bad public consultations in this province," said Gathercole, and the Council was determined to do it right.

The public involvement process consisted of the following steps:

- A mailing was sent to about 800 organizations and individuals, requesting comments on the scope, priorities and principles for the energy strategy. The Council received over 200 written responses.
- A discussion paper was prepared based on these responses outlining the Council's proposed approach, and requesting comments on guidelines for the strategy, principles of sustainability, specific areas of energy policy to be focussed on and the processes for public involvement.
- A series of "brain-storming sessions" were held to broaden the range of ideas on the table.
- Four consultative groups were established to provide input on the energy strategy as a whole and on the three issues determined by the public to be most important: space conditioning (heating and cooling) and water heating, wood residues (the use of wastes from the pulp and paper industry as an energy resource) and transportation. Each of these groups consisted of representatives of 15 to 20 groups, with staff support from the Energy Council. Their monthly meetings were open to the public.

[77] *Ibid.*, p. 145.

- An information bulletin was sent out once a month, and a series of background papers were produced and distributed free of charge.

- The Council released its draft strategy and a 30-minute video entitled *Energy Sustainability and the Planning of Cities and Towns,* and toured the province to solicit comments from the public.

C. Recommendations

The recommendations of the B.C. Energy Council are found in its final report, *Planning Today for Tomorrow's Energy: An Energy Strategy for British Columbia,* released on November 22, 1994. This 150-page report, written in clear and direct language, starts with the idea that "business-as-usual is not sustainable," and attempts to determine both what energy sustainability would look like and how it can be achieved. *Sustainable energy systems* are those which are fully renewable and which have acceptable environmental, social, health and cultural impacts. The report also seeks to define *transitional energy strategies* — those which do not themselves meet all these criteria but which will ease the transition to a fully sustainable economy.

Key points and recommendations will be described briefly below.

a. Development strategies to favour sustainability

The Council is of the view that it is impossible to achieve energy sustainability without changing *energy service levels,* in addition to the technologies used to supply them and the efficiency of end uses. This does not require deprivation; "on the contrary, people are now beginning to understand that it can mean a high quality of life of the type they are seeking anyway."[78] For instance, in addition to looking at vehicle efficiency and fuels, it could involve looking at the way new communities are planned, so as to minimize the need of their future inhabitants for *transportation services.* Thus, the Council views municipal and regional planning as key elements of a energy sustainability, since "people and agencies who often are not concerned with energy costs or impacts make the basic decisions that determine how much energy is use."[79]

As well, the Council developed a number of sustainability principles specific to energy. These include:

- *a definition of sustainable energy supply that is not limited to strict renewability, but that also includes environmental and social impacts as well as the sustainability of related activities.*

[78] *Ibid.,* p. 17.

[79] *Ibid.,* p. 19.

For a supply option to be considered sustainable, its impacts must be acceptable to those who bear them, and must not exceed the carrying capacity of the ecosystems affected. Thus, some renewable energy sources are not sustainable. For instance, "large amounts of biomass energy from wood residue could be renewed indefinitely, but the methods of harvesting wood from forest ecosystems may not be acceptable on ecological grounds."[80] Similarly, the Council considers large-scale hydroelectricity to be unsustainable, since dams flood productive river valleys and disrupt their ecosystems, and promote a boom-and-bust type of development that runs counter to the long-term interests of local communities.

- *recognition of the importance of transitional fuels and strategies.*

Clearly, it is not possible to convert immediately to sustainable energy systems. Rather, energy decisions "should be judged on the basis of whether or not they move society towards this goal."[81]

Since energy infrastructure built today will last for a very long time, it is essential to make choices now that not only meet current needs, but also can be converted to future, more sustainable, energy supply or demand options at reasonable cost. It also implies high levels of energy efficiency: "super-efficient houses heated by small amounts of (unsustainable) natural gas can be converted to sustainably provided solar or electric heat more easily than an inefficient electrically heated house.[82]"

The Council is of the view that natural gas has an important role to play as a transitional fuel, since most infrastructure and technologies developed for gas could easily be converted to hydrogen when hydrogen technologies mature. However, "natural gas's transitional role does not warrant blind substitution or promotion of its use. It involves specific, forward-looking, high-efficiency applications whose building, equipment or infrastructure designs do not constrain conversion to a sustainable energy supply."[83]

- *recognition that both competition and regulation play important roles in moving toward sustainability.*

Competition tends to reduce the cost of goods and services that have a price, but those reductions may be achieved at the expense of things which do not have a market price. "The challenge is to determine when and where energy sales and transmission contracts based solely on competitive principles fit within the public's economic, social and environmental interests."[84] The Council favours a "made-in-B.C.-for-B.C." approach to answering this question, based not on theory or ideology but on desired outcomes.

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[80]*Ibid.*, p. 22.

[81]*Ibid.*, p. 22.

[82]*Ibid.*, p. 24.

[83]*Ibid.*

[84]*Ibid.*, p. 123.

Other sustainability principles include,

- *the intrinsic value of locating energy supply close to its point of use, so that the environmental and social impacts of its production are evident to and borne by the user,* and

- *the value of integrated resource planning processes which directly involve those who receive the benefits and those who pay the costs of energy-related decisions.*

b. Municipal and regional planning

Referring to the suburban model of development as "a 40-year experiment that failed," the Council is strongly in favour of the *urban village* concept for new communities. Compared to traditional suburbs, developments of this type include smaller, adjoining residences (reducing space heating requirements), mixed neighbourhoods including both residential and commercial buildings (reducing transportation problems), and street grids instead of the suburban cul-de-sac (reducing the cost per residence of linear infrastructures like roads, sewer and water lines). Energy-efficient construction, district heating and combined residential/commercial ground source heat pumps all contribute to the energy sustainability of new developments.

The Council also strongly advocates community-based energy planning to sponsor and coordinate energy efficiency programs for utilities, businesses and homes. It advocates the application of integrated resource planning principles at the local or regional level to consider a wide range of energy options. Off-grid communities, in particular, have a very wide range of choices and, given the high cost of new lines or gas mains, resources which are not yet be cost-effective for the province as a whole may well be part of the optimal energy strategy for such communities. Such local IRPs need not be expensive. Working with a utility or with consultants, the Council suggests that the process should take no more than a few months.

c. Transportation

The Council recognizes that transportation uses more energy than the commercial and residential sectors combined and that, since oil companies are not utilities, the traditional regulatory approaches cannot provide a solution. In keeping with its long-term mandate, the Council focusses primarily on the ways that urban and regional planning determine patterns of energy use. Thus, it states that, "Rethinking how cities and towns are developed is fundamental to creating an energy-conserving transportation system."[85] This would involve measures to reduce the underlying demand for transportation services and to shift the ways people move around (by favouring public transit).

[85] *Ibid.*, p. 77.

Detailed recommendations are made for a number of transportation problems, but the underlying approach is that integrated resource planning principles be applied to transportation planning at both the provincial and regional levels, in order to ensure that a wide range of options are examined.

d. Greenhouse gas reduction

In order to meet the greenhouse gas targets to which British Columbia is committed, "unprecedented, innovative policy measures would have to be taken immediately. ... Many of these measures are worth doing anyway in that they make economic sense independent of the environmental effects of greenhouse gas emissions." However, the Council does not draw a clear line between greenhouse gas strategy and energy sustainability. "All recommendations intended to reduce fossil fuel use or appropriately substitute fuels are greenhouse gas recommendations. ... For example, recommendations that would result in denser or mixed-use urban zoning and those encouraging district energy systems are, among other things, greenhouse gas recommendations."[86]

As noted earlier, the Council does not consider hydroelectricity to be sustainable, due to its large site-specific impacts. Thus, "an energy sustainability strategy cannot deal with the greenhouse gas issue by off-loading the problem onto large hydro development."[87]

e. Distributed generation

Distributed generation refers to the situation where an energy consumer generates his own power and thereby buys less from the utility. From the utility's perspective, distributed generation is a demand-side resource, but from a broader perspective, it is a supply-side resource.

The Council considers distributed generation to be a key element of a sustainable energy future. It sees an intrinsic value in locating energy supply close to the point of use, because the environmental and social impacts of energy production are then "evident to and borne by the user of the energy."[88] It also results in lower transmission and distribution losses, and less need for new T&D investments.

The Council expects distributed generation technologies to be widely available and cost effective in a not-too-distant future. These technologies include fuel cells, photovoltaics and micro-cogeneration units, as well as very small hydro and wind power. Other distributed technologies that do not generate electricity, but that can replace it, include ground-source heat pumps, solar space and water heating, and district heating, which can be linked to municipal cogeneration.

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[86]*Ibid.*, p. 33.

[87]*Ibid.*, p. 43.

[88]*Planning Today for Tomorrow's Energy*, p. 6.

> "Distributed technologies ultimately could spell the end of utility planning as we know it. The users of electricity would buy generation technology in competitive markets in the same way they buy appliances or building materials. The grid would be used mostly for back-up and at times of peak demand. Long-range forecasting and central station and major transmission line planning would fade in importance."[89]

At the same time, the Council points to several elements of current policy that discourage distributed generation. For instance, the fact that electric rates reflect average system cost, which is lower than the cost of new supply (marginal cost), tends to discourage investments in distributed generation, even when it is less costly than other new supply, since the only payback for the customer is the savings on his electric bill. Also, the Council recognizes that distributed generation is usually a "lost opportunity resource" that is much more cost-effective if installed at the time of construction or major renovation. B.C. Hydro is now willing to pay up to 2.5 cents/kWh for energy at all times; the Council seems to favour adjusting this policy to explicitly favour lost opportunity resources.

f. Integrated resource planning

The Council is very supportive of the utility IRP required under the B.C. Utilities Commission guidelines, and of the Commission's extension of IRP to natural gas distribution utilities. It also recommends extending the concept even further. While recognizing that this has never been systematically done, it favours the application of IRP to transportation, with public transit and better urban planning playing the role of DSM in utility IRP. It also recommends a shift from province-wide to regionally-based IRP, which "reflects shifts to small-scale, site-based electricity generation technologies and to geographically targeted DSM programs." Thus, it urges that B.C. Hydro carry out a series of local or regional IRPs, which "supports the principle that the parties who directly reap the benefits and pay the costs are the ones who need to be consulted."[90] Finally, it urges the Utilities Commission to move toward integrating the IRPs of the various utilities it regulates.

Furthermore, "sustainable electricity resources tend to be located on or near customer premises and therefore their development requires the involvement of the customer. Local interests should be approached for solutions and business arrangements, not only for opinions."[91]

g. Social costing

Social costing can be defined as "an attempt to estimate what energy costs — and therefore prices — would be if the economy was perfectly competitive," that is, in an ideal world where all environmental and social costs were internalized into prices. "Social costing policy is based on the assumption that the best resources are the ones of least total cost, including those costs (impacts) not paid in money. Economic theory asserts that least-cost resources would be the ones developed

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[89]*Ibid.*, p. 125.

[90]*Ibid.*, p. 121.

[91]*Ibid.*

in a perfectly competitive economy."[92]

Each of the energy planning bodies discussed in this report use the principles of social costing in one way or another. The CCS requires that all Crown corporations use multiple accounts evaluation, a social-costing approach, in evaluating capital expenditures, and the B.C. Utilities Commission requires it of all utilities in their IRPs.

The Energy Council report makes specific recommendations regarding the appropriate methodologies for social costing. It comes out strongly against the monetization of environmental damages, an approach widely used in the United States, especially for air emissions of fossil-fuel power plants. The Council points out that the hydroelectric and wood-residue resources that make up much of British Columbia's energy mix lend themselves much less easily to generic monetized costs, since their impacts are highly site-specific. Stating that, "importing a methodology tailored to U.S. environmental problems will not do justice the B.C. situation," the Council calls for "a 'made-in-B.C.' social costing methodology that reflects the province's own resource base and environmental issues."[93]

The Council argues that approaches based on monetization inevitably oversimplify the complex, uncertain and variable nature of most environmental impacts. It notes that even without monetized values, environmental impacts can still be accounted for in decision-making, and calls for processes "that bring together an informed body of stakeholders to evaluate the multi-dimensional trade-offs among resource options." These stakeholders, provided with full technical support, can then look at the trade-offs between environmental, economic and other attributes for a wide range of alternatives. "A major strength of the stakeholder approach is that it is constructive, encouraging consensus and real decisions."[94]

h. Energy pricing and taxation

It must be noted, however, that these applications of social costing apply only to the selection of new resources; they have only a small and indirect impact on actual energy *prices*. The Energy Council fully supports social costing, but believes it should be carried further into actually internalizing social costs into energy prices.

The Council's report notes that the idea of increasing energy prices to reflect social and environmental costs was supported by a large majority of the individuals and groups it consulted. However, such an approach is not without costs, since "a policy that results in higher energy prices

[92]*Ibid.*, p. 53.

[93]*Ibid.*, p. 118.

[94]*Ibid.*, p. 120.

adversely affects every car driver and utility bill payer in the province."[95] As well, it would reduce the profitability of many industries, and could lead to perverse effects if only applied to some energy resources. In particular, the Council notes the danger of increasing costs of regulated sources but not unregulated ones.

The Council's answer to these problems is to increase energy costs through a surcharge, but for all additional government revenues to be returned to energy service markets in ways that support sustainability. This type of dedicated surcharge is referred to by the Energy Council as *"closed-circuit taxation."* "The public input received on this issue clearly indicates that there is support for a closed-circuit taxation and financing mechanism *only* if the government is forced to spend the tax money collected in specific, predetermined ways. ... Unequivocally, there is *no* public support for energy taxation that flows into general revenue."[96]

As for the nature of the surcharge, the Council expresses a preference for one on the basic energy content of fuels and electricity — often referred to as a "BTU tax" — as opposed one based on carbon content. This is primarily because carbon taxes or greenhouse gas taxes create a bias that favours certain energy resources over others. For instance, they tend to make large hydro projects look more desirable, since their greenhouse gas emissions are usually considered to be very small.[97] As mentioned earlier, the Council considers that large hydroelectric projects are not sustainable; thus, a surcharge that selectively penalizes fossil fuels but favours hydroelectricity would not be in the interest of energy sustainability.

The main benefits of this type of dedicated surcharge is that they would increase prices to the level where they approximate the real costs to society of new energy resources, and at the same time provide a means of financing measures that will lead closer to energy sustainability. The Council proposes several mechanisms for reducing the burden on low-income consumers and small businesses (e.g. exemptions or rebates) and for ensuring that the change produces neither windfall profits nor financial harm for utilities or oil companies. These latter mechanisms are similar to those used to *decouple* profits from gross sales — an important goal of IRP, since as long as increased sales produce increased profits, utilities have a strong disincentive to promote conservation. Many decoupling mechanisms are used in various jurisdictions in North America; as noted earlier, in its last rate decision, the B.C. Utilities Commission effectively "decoupled" B.C. Gas.

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[95] *Ibid.*, p. 55.

[96] *Ibid.*, p. 58.

[97] Recent research has cast some doubt on this widely held belief. Studies from the Freshwater Institute in Winnipeg and from the Université du Québec à Montréal have shown substantial quantities of methane — a powerful greenhouse gas — released from hydroelectric reservoirs. More research is needed before it will be possible to accurately estimate the actual greenhouse-gas impacts of hydroelectric reservoirs. It seems clear, however, that these emissions vary considerably depending on the physical characteristics of the reservoir, and that, at least in some cases, they may be substantial.

i. Retail and wholesale wheeling

Among the questions raised by the profound restructuring underway in the American electric industry is that of retail/wholesale wheeling, or transmission access. These terms in effect refer to introducing competition into the electricity supply markets, either at the wholesale or the retail level.

The Council is entirely favourable to wholesale wheeling. Given the existence of small-scale, highly efficient generating technologies, there are no longer significant economies of scale in electric generation, and thus the Council considers that it is no longer a natural monopoly; thus, there is no reason that there should not be a competitive wholesale market for electricity, as there is for natural gas.

The Council is thus of the view that wholesale wheeling is compatible with the existing generating technologies, and that it is also consistent with integrated resource planning and with energy sustainability. This is because competitive procurement of electricity by distribution utilities (which still are regulated natural monopolies) does not interfere with their ability to choose between supply- and demand-side resources on the basis of their financial, environmental and social costs. It also supports the unbundling of electric services — providing a variety of different types of electric service at different rates (interruptible service, backup service for self-generators, etc.).

At the same time, the Council is of the view that, given the technological structure of today's electric industry, retail wheeling — sale of energy to a consumer by a producer other than the local utility, implying open access to transmission and distribution equipment — is *not* compatible with the goal of sustainability. Integrated resource planning requires that utilities take environmental and social costs into consideration in making decisions regarding the generation or purchase of electricity, and that demand-side resources be given equal consideration to supply-side resources. Under a retail wheeling structure, however, sales would be made directly between producers and consumers, based on exclusively financial considerations, resulting in a strong bias toward cheap supply-side resources, regardless of their environmental or social impacts.

The Council also notes that there is no significant pressure from within British Columbia for retail wheeling, as there is in the United States, in part due to B.C.'s low electric rates. The only real pressure of this nature comes from industrial customers with their own generation equipment that would like to be able to wheel their excess power to their other plants.

The Energy Council's opposition to retail wheeling is thus based on its view that it would hinder society's efforts to create sustainable energy systems. The Council is convinced that a sustainable energy future must be based on *distributed* technologies, which are more efficient and have smaller environmental impacts than do equivalent centralized generating stations, avoiding the costs and impacts of transmission.[98] As well, they also make energy production and its impacts more evident to the user,

[98]High-voltage electric transmission projects arouse as much public opposition in B.C. as do generation projects, probably because they have a greater direct impact on areas of greater population density.

creating a powerful incentive to use energy more prudently.

The Council argues that implementing retail competition at this stage would slow down the commercialization of distributed technologies. Similarly, retail competition at this stage would restrict utilities' investment in demand-side measures, since, even if they continue to provide demand-side services on a competitive basis, they would have to compete against private power, which would be priced at its financial cost, not its social cost. However, once distributed technologies mature, the Council believes that retail competition might become desirable.

j. Demand-side management

The Council recognizes that customer rebate and information programs are not in themselves very effective, "a slow and costly method for moving markets to greater efficiency."[99] It considers rather that DSM programs should seek to permanently transform markets, so that the programs themselves are only transitional. It points to some of B.C. Hydro's Power Smart programs as a model, such as rebate programs for refrigerators and motors that have managed to shift the market to more energy-efficient models.

While current DSM programs still focus primarily on broad, customer-oriented programs, the Council suggests that, in the future, they will focus more on targeting specific customer groups and geographic areas where there is more "bang for the buck" and on manufacturers' incentives, preferably in coordination with other utilities, like the $30-million "golden carrot" being offered by a group of 24 U.S. utilities for the manufacture of a CFC-free refrigerator that meets much more stringent efficiency standards.

As well, the Council recommends:

- that utilities give priority to capturing "lost opportunities," such as new building construction and industrial retrofits, even if the electricity is not currently needed. If energy-efficient choices are not taken immediately in these situations, the resulting inefficiencies will last for many years to come, raising future energy supply costs,
- that the effect of rate structures on consumption not be ignored,
- that DSM programs be targeted on a local basis based on avoided transmission and distribution costs, which vary considerably from one region to another, and
- that there be consistent rules for determining the cost-effectiveness of proposed DSM programs, and for assessing their performance.

[99] *Ibid.*, p. 129.

k. Governance

The Council's report addresses the structural characteristics of government (it refers to these aspects as "governance") which stand in the way of the kinds of reforms discussed elsewhere in the report. Much of the problem ultimately is related to the fact that the provincial economy historically was based on *harvesting resource commodities*, not on providing services or managing the territory. The ministerial structure of government is based largely on these commodities, resulting in significant overlap as well as significant lacunae.

Thus, one small area may be simultaneously a forestry resource, a tourist attraction, an energy resource, a job-creation site, an ecological sanctuary and a distinct nation, with each aspect managed by a different Ministry. These overlapping and often conflicting mandates make it very difficult for sustainability to become a serious priority.

The situation is similar for transportation energy policy. The choices that determine how much and what kind of energy will be used for transportation are made by a multiplicity of bodies, including the Ministry of Transportation and Highways and the Ministry of Municipal affairs, and Crown corporations like B.C. Transit and B.C. Ferries, none of which have a mandate to manage energy consumption. The Energy Management Branch of MEMPR has only limited input into transportation policy. The result is that sustainability planning falls through the cracks.

The Energy Council also pointed to a lack of political leadership in energy sustainability, but made no specific recommendations regarding governance, arguing that the question is not limited to energy policy, and must be addressed in a broader forum.

D. Discussion

The Energy Council's report, *Planning Today for Tomorrow's Energy*, is an important document, and not only for British Columbia, in that it lays out in clear terms what it would mean for energy use to be sustainable. It is not clear, however, to what extent its recommendations will be put into effect. An inter-ministerial committee has been set up within the B.C. government to examine this question.

As noted earlier, it appears that the Energy Council's functions will be largely folded into the mandate of the B.C. Utilities Commission. Also, part of the Energy Council's mandate may be devolved to the new "Sustainability Council" being formed at the Whistler Centre for Business and the Arts. This Centre will be even more "arm's-length" than was the Energy Council — it will have no formal ties to the government at all, though it appears to have government support. The idea is "to bring government and non-government together to work out solutions, not to be an advocacy group" according to Richard Gathercole, former head of the Energy Council and one of the organizers of the Centre.

IV. CROWN CORPORATIONS SECRETARIAT

As noted in the Introduction, the Crown Corporations Secretariat (CCS) is a quasi-governmental body which oversees the 14 Crown corporations in B.C. Its mandate is to enhance the cooperation among Crown corporations and to help them improve their decision-making processes, especially with respect to capital spending. The CCS plays an important role in the oversight of B.C. Hydro (the only Crown in the energy sector); it is also of interest in that the analytical framework that it has mandated for all the Crowns, known as multiple account evaluation (MAE), is intimately related to integrated resource planning.

The CCS was set up in 1992. In February 1993, it issued its *Multiple Account Evaluation Guidelines*, which serve as a planning framework for all the Crown corporations. They have also been used by many investor-owned utilities in B.C. as the basis for the multi-attribute trade-off analysis mandated by the B.C. Utilities Commission.

For the most part, the CCS works with the Boards of Directors of the Crown corporations. Ken Peterson, a former Director of Planning at B.C. Hydro, was Acting Asst. Secretary of the CCS in 1992, and continued to handle energy issues there until the end of 1994, when he became President of B.C. Hydro's power export subsidiary Powerex. According to Peterson, the CCS has been able to work directly with both the management and the Board of B.C. Hydro in a way that it is very difficult for the government to do directly. “The Boards are often simply neglected, because the government finds it easier to deal directly with the Chair or the CEO,” he said.

B.C. Hydro's Board is unusual in a number of respects. Since the 1980s, it has been regionally balanced, with members from every region of B.C., including Native representation. (Since 1992, it is also gender-balanced.) Members are not all from the business community, but come from all walks of life. The role of the CCS is to help provide them with the tools to judge what they get from management — a problem also shared by sophisticated Boards, says Peterson.

The fundamental priority of the CCS has been to promote synergies among the different Crown corporations (e.g. between Ferries and Highways) and to bring fresher thinking to the way they approach planning. In particular, the CCS has tried to bring greater rigour to the way the Crown corporations approach capital spending. It was noted that, while some of the Crowns used relatively sophisticated techniques to ensure that capital spending was prudent, others were quite primitive. In this regard, B.C. Hydro was one of the leaders, and, according to Peterson, one of the purposes behind the CCS was to induce the other Crowns, particularly those involved in transportation, like B.C. Ferries, B.C. Transit and B.C. Rail, to emulate B.C. Hydro's approach to evaluating supply-side and demand-side alternatives.

Even though it was not carrying out explicit and methodical integrated resource planning, since the late 1980s, B.C. Hydro has been actively pursuing demand-side alternatives to new capital spending through its Power Smart programs. One of the key goals of the CCS has been to transplant this "demand-side ethic" to the other Crowns. This would mean, for instance, that instead of automatically building more highways as traffic increases, less expensive demand-side solutions such as reserved lanes and better transit should also be considered. Similarly, instead of automatically adding more trains and more ferry terminals to respond to increased rush-hour congestion in the mass-transit system, inexpensive off-peak fares can be used to divert some travellers away from the peak periods.

Of course, to be able to decide among such different alternatives requires much more sophisticated information than is needed to choose among supply-side alternatives, including marginal costs per user for new supply-side alternatives and the cost implications of the various demand-side solutions, which differ significantly one from the other.

Furthermore, in keeping with the government's commitment to the incorporation of environmental, social and other non-monetary factors into decision-making, the CCS developed its Multiple Account Evluation Guidelines to help the Crowns compare very different strategies on the basis of a broad range of interests and objectives, including but not limited to the strictly financial, within an integrated planning framework.

A. Multiple Accounts Evaluation Guidelines

The multiple accounts evaluation approach begins with "developing a clear understanding of the problem or opportunity it is intended to address and then identifying the full range of alternatives to which it should be compared. ... It is the creativity and thoroughness brought to bear in the identification of alternatives where the greatest potential gains can be realized from the evaluation process."[100]

The MAE approach involves assessing the performance of alternative plans and projects under several different "accounts". In general, the CCS proposes the use of five main accounts, and each account may have several sub-accounts. However, the list is not set in stone, and can be adjusted to meet the needs of the particular problem under study. It is important to note that some of the accounts are monetary, some are quantitative and some are qualitative. Under the MAE methodology, there is no need to represent all impacts in the same units.

While the choice of accounts can be tailored to the particular situation of each agency, the main accounts are typically the following:

- financial performance: revenue and expenditure implications from both a corporate and a broader government perspective,

[100] Crown Corporations Secretariat, *Multiple Account Evaluation Guidelines* (February 1993), p. 6.

- customer service: the net benefit or value derived from the alternatives by customers or users,
- environment: the nature, magnitude and significance of the major biophysical and natural resource impacts of the alternatives,
- economic development: the nature, magnitude and significance of the income and employment impacts of the alternatives, and
- social: the major impacts of the alternatives on the social fabric, values or goals of affected communities, including aboriginal communities.

The MAE Guidelines do not present any explicit methodology for making trade-offs among the various accounts. Their purpose is simply to identify the varied types of impacts of each alternative, and to present them in a structured and easily understood way. However, the MAE can in effect be used as *input* to a more sophisticated decision analysis. This was seen in the West Kootenay Power IRP (p. 38).

In effect, two distinct methodlogies were used there. First, each account in the MAE was "normalized" on a scale of 1 to 3. That is, the alternative with the best result for a given account was given a score of 1, the one with the worst result was given a score of 3, and the others were arranged proportionately between these extremes. This is an elegant way to introduce a single but non-monetary measure among all the accounts, allowing them henceforth to be combined (according to pre-determined weights) into a single score. Unfortunately, this approach has two flaws. The first is that, even if the weights are derived by participatory and democratic means, the participating individuals have no clear methodology to arrive at their own weightings, which thus have a somewhat arbitrary nature. (This problem was answered in the WKP with the observation that the outcome was quite robust, in that it did not vary with the choice of weightings.)

The second and subtler flaw has to do with the "normalization" to a scale 1 to 3. The problem is that this approach treats the financial account differently from the others, in a way which may in some cases bias the outcome. For the financial account, the project with the best benefit/cost ratio is given a 1, the one with the worst is given a 3, and the others are interpolated between them. This means, of course, that there is always one option that has a "perfect" financial score of 1. This is not true for the other accounts, where scores were given directly by participants, on a scale from 1 to 3. As a result, it is not entirely clear how the financial account should be compared to the others.

The second methodology used by WKP is a "multi-attribute trade-off analysis," known in B.C. by its acronym MATA. In effect, the MAE scores are used as input in the MATA process, which compares the net performance of several different *portfolios* of resources (as opposed to individual resources) with respect to several different attributes (accounts).

The MATA process was discussed earlier (p. 38). While it is very compatible with the MAE process proposed by the CCS, it does not form part of their Guidelines.

B. Oversight of B.C. Hydro

Under the *Utilities Commission Act*, the Cabinet can give special instructions to the Commission to govern its treatment of B.C. Hydro. Eight of these Special Directions have been issued to date. The first, issued in March 1981, soon after the creation of the Utilities Commission, gave it instructions that B.C. Hydro's rates should be set in such a way as to permit it achieve a financial position allowing it to borrow money "on the most economic terms available." Specifically, it established that rates should be sufficient to permit an interest coverage ratio (the ratio of gross income to interest charges) of 1.3, in order ultimately to establish a debt-to-equity ratio of 80%.[101]

Special Direction #3 to the Utilities Commission, issued in 1989, recognized "that electricity rates should gradually increase to meet the higher costs of new electricity supply," but instructed the Commission to ensure that rate increases were "smooth, stable and predictable and contribute to conservation and efficient electricity use." It further reiterated the financial criteria first articulated in 1981.

Since its creation in 1992, the CCS has played a key role in developing these Special Directions. In particular, it developed Special Direction No. 8, issued in November 1992, in which the financial criteria under which the Utilities Commission sets B.C. Hydro's rates were changed. This Special Direction specifies that the rates for B.C. Hydro shall be set so as to allow the company to earn a return on equity "consistent with that earned on a pre-income tax basis by the most comparable investor-owned utility regulated under the Act." It also caps B.C. Hydro's rate increases at 2% over inflation. The CCS estimates that this change will increase B.C. Hydro's dividend payments to the government by over $150 million a year.[102]

This Special Direction has been extremely controversial, both from a technical and from a political point of view. From a technical point of view, it gave rise to complex debates about on what accounting basis such a comparison should be made and on what is "the most comparable investor-owned utility" — clearly, due to its size and its status as a Crown corporation, the differences between B.C. Hydro and any private utility in B.C. are far greater than the similarities.
Political opposition to the Special Direction was due to the fact that it adds considerably to B.C. Hydro's payments to the provincial government. This was seen by many as a revenue grab, milking the utility as a cash cow at ratepayers' expense. "The government sees B.C. Hydro as a way to spend

[101]In contrast, Hydro-Québec's interest coverage has not exceeded 1.1 since 1989. Its debt-to-equity ratio target is 25%, below which it cannot pay dividends to the government; the figure has hovered around 24% since 1989.

[102]Crown Corporations Secretariat, *Annual Report 1992-93*, p. 8.

money in the province without raising taxes - it raises rates instead to pay for it," said Brian Wallace. In his view, the real reason behind Special Direction #8 was the decline in interest rates, which resulted in significant savings for B.C. Hydro. Rather than allowing rates to decline, the government simply appropriated the surplus, he said.

The CCS has also been involved in many other aspects of B.C. Hydro. It has helped to develop policy with respect to exports and purchases from IPPs, it has undertaken a review of Power Smart programs, and worked with the Ministry to set up a major Electric System Operating Review. It also was actively resolved in planning the negotations regarding the downstream benefits of the Columbia River Treaty with the United States.

V. THE ENVIRONMENTAL ASSESSMENT ACT OF 1994

A new Environmental Assessment Act was passed in 1994 by the B.C. Legislature. Draft regulations have been issued, but the new law has not yet come into effect. The new law changes the procedures for environmental assessment of energy-related projects in several significant ways.

Under the former procedure, review of energy projects was coordinated by the Ministry of Energy, Mines and Petroleum Resources (MEMPR), with the involvement of the Environment Minister on certain elements. Responsibility for licensing and authorization of energy projects was divided: for minor projects, it is the exclusive jurisdiction of the Utilities Commission. For major projects, the final decision is made by Cabinet, based on recommendations from the Utilities Commission following public hearings. Prior to the hearings, the application was reviewed by an inter-agency Energy Project Coordinating Committee, which included representatives of MEMPR, the Environment Ministry, the Utilities Commission and the Federal Environment Assessment Review Office (FEARO).

The new regime which is about to come into effect includes many detailed procedural changes. One of these changes dramatically reorganizes the relationship between environmental assessment and energy planning: energy projects will only be permitted into the environmental assessment process if they have already been approved by the Utilities Commission as part of an integrated resource plan.

This simple device resolves the contradiction that has plagued decision-making on energy projects in Québec and in many other jurisdictions, where environmental review boards find themselves having to assess every aspect of a utility's energy planning in order to assess the justification of the project before them. While most observers agree that this is an anomaly, it has been almost impossible to avoid, since the environmental impacts of energy development can only be considered acceptable in relation to both the need for the energy and the available alternatives.

Public participation has long been accepted in environment assessment, while it is only now that it is becoming the norm in energy planning. As long as energy planning has not been subject to public review, it is more or less inevitable that environmental and other public interest groups will insist that their concerns be addressed in the one forum available to them. The solution in the Environmental Assessment Act is thus one which will greatly reduce the burden on environmental assessment panels to have to look at energy planning issues.

Interestingly, for the civil servants who are designing this new system, this is not even the primary benefit. For them, the primary benefit is that the environmental review mechanism will not even have to look at projects whose justification has not already been accepted. “We don't have the resources to waste reviewing projects that will never see the light of day,” said John Allan, the Deputy Minister of Energy in charge of the development of the new law.
The other side of this contradiction is that energy regulators should not have to sign off on projects in the IRP process, when they only have a general and qualititative idea of the project's impacts. And it would be inappropriate to require detailed environment impact assessments, including mitigation and compensation strategies, at such an early planning stage. The new system has a solution for this impasse as well: after environmental assessment, energy developers still will need a project authorization (a “Certificate of Public Convenience and Necessity,” or CPCN) issued by the Utilities Commission.

The process then works as follows: if a utility's IRP includes new energy projects within a near-to-medium time frame, and if the IRP is approved by the Utilities Commission, the projects go to environmental assessment. The assessment process is focussed more on identification and mitigation of impacts than on approval/disapproval, since there is already a presumption that the project is the best of the available alternatives, which were studied, along with a rough estimate of their environment impacts, in the IRP. When this process is completed, if no major unexpected impacts have been uncovered in the environmental assessment process, the developer goes back to the Utilities Commission for a CPCN. If, and only if, the Commission is convinced that the project is still the best solution, it will issue the authorization for construction to begin. If, however, demand projections have changed, or if mitigation measures required as a result of the environmental hearings significantly increase the project's cost, the Utilities Commission can still deny the certificate.

It should be noted that the Utilities Commission has jurisdiction not only over the construction of new energy resources, but also over the operation of existing ones. Thus, its role is not over once it has authorized construction. Any problems or complaints that arise during construction or operation all come back to the Commission, assuring informed oversight over the entire process.

For major projects, the process is the same, except that, as under the current system, final approval must be given by Cabinet.

VI. INTEGRATED RESOURCE PLANNING CONCEPTS AS APPLIED IN BRITISH COLUMBIA

While it is the B.C. Utilities Commission that is most explicitly involved with integrated resource planning, many of the essential concepts of IRP are also found in the other institutions that make up the planning and regulatory framework in B.C. These essential concepts can be described as follows:

- ensuring that demand-side alternatives to meeting energy service needs are considered on an equal footing with supply-side alternatives,
- seeing that externalities (environmental and social costs and benefits) are taken into account in choosing new energy resources,
- ensuring that decisions are made in a transparent process, to which the public has access and in which it takes part, and
- ensuring that the risks and uncertainties inherent in planning for the future are fully recognized, and that robustness in the face of these uncertainties be a key consideration in planning.

It is now possible to see how the major elements of IRP are being applied in British Columbia.

A. Energy efficiency: a level playing field

Recognition of the importance of demand-side alternatives is now a given throughout the B.C. energy world. This principle is well established at B.C. Hydro and the other utilities via Power Smart, and it figured prominently in the deliberations of the B.C. Energy Council. Under the Utilities Commission's IRP Guidelines, demand-side resources must be clearly identified and compared to supply-side resources.

An interesting feature of the Utilities Commission's regulation of rates is its oversight over demand-side programs. Typically, demand-side programs first come before the Commission when a utility requests a “deferral account,” whereby it requests that expenses for developing a particular program be deferred, to be recovered through rates when the program begins to operate. Perhaps surprisingly, the Commission has been severe in approving these deferrals. As for any supply-side project, the Commission needs to be convinced that the expense is prudent — not only that the program will work, but that it is well designed and is the best and most cost-effective of the available alternatives. Thus, of 20 specific demand-side programs proposed by B.C. Gas in its 1994 IRP, the Commission rejected 7 outright, judging that they were either poorly designed or showed little benefit in relation to their costs. For most of the rest, it approved scaled-down pilot projects only, requiring that the utility come back again for further approvals. This attention to detail and to minimizing the rate impacts of DSM is one of the reasons for the Commission's broad support, not only among environmentists, but among industrial consumers as well.

B. Externalities

Referred to in B.C. as “social costing,” mechanisms to integrate externalities into decision-making are central to the functioning of each of the bodies described in this report.[103] Perhaps the key achievement of the Crown Corporations Secretariat, for instance, is the application of social costing to decision-making by all the Crown corporations through its Multiple Account Evaluation Guidelines. Similarly, the Utilities Commission's IRP Guidelines make clear that externalities must be fully represented in the IRP decision-making process.

It can be argued that there is a certain redundancy in the way that social costing has been taken up by each of the agencies discussed in this report. The industrial consumers insist that these multiple social costing exercises are redundant and wasteful. In his final argument on their behalf in the last B.C. Hydro rate case, R. Brian Wallace stated, “We are concerned that this leads to duplication of efforts and wasted time and expense as each group studies the problem and then attempts to justify their approach on a very difficult topic. The Commission must do everything it can to bring all social costing efforts together in one place.”

The social costing exercises proposed by the CCS, and those carried out by B.C. Hydro and the other utilities, all are focussed on making sure that externalities are taken into account in the selection of new resources. The B.C. Energy Council's final report takes the concept of social costing one step further. It recognizes that using social costing in decision-making regarding new resources goes only a small part of the way toward the economist's theoretical goal of “internalizing the externalities.” Ideally, that is, all environmental and social costs of energy development should be compensated, and the costs made part of the market price of the energy services; if this were the case, the market itself would restrict energy use to the level at which users were willing to compensate the harm they indirectly cause. From this economic point of view, the fact that the price signals to consumers do not include these externalities is one of the main reasons why regulation is required.

Using social costing for selecting new resources has only a small impact on prices.[104] Even if a more expensive resource is chosen over a cheaper one because its “social cost” is lower, this higher cost will be greatly diluted when it is averaged into the total system costs; it is only after such a system has functioned for many years that actual prices will start to reflect the premium paid for lower-

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[103]AS noted earlier, "social costing" is the term used in B.C. to refer to the determination fo the total cost of a resource to society, including its direct and indirect financial cost, environmental impacts and social impacts.

[104]The term “cost” refers to what it *costs* a producer to generate a unit of energy; its *price* is the amount paid for that unit by a consumer.

impact resources, and even then, the actual impacts of energy production still would not be internalized into prices.

The process can be carried one step further by using social costing in *dispatch* as well as in the selection of new resources. That is, in systems which have substantial amounts of cheap but dirty resources, significant environmental gains might be obtained if social cost rather than financial cost where used to determine which resources to shut down when the system is not running at full capacity. This could result in a greater price impact than when social costing is used only for resource selection, since less polluting, higher-cost resources would be used much more frequently.

The B.C. Energy Council proposes going even farther, to the direct internalization of externalities through dedicated surcharges. Under this concept, a tariff would be applied to all energy sold, in order to bring its price to a level that actually represents the cost to society of its use. Money from such a surcharge would not go into general revenues, however; it would be earmarked to compensate actual damage or, more likely, to fund demand-side programs that reduce the overall cost to society of meeting energy needs.

Such a surcharge would make it possible to resolve many of the conundrums of energy economics. In theory, it could remove the two greatest objections to retail competition: the loss of utility funding for DSM, and the inevitable result that the producers who would win out in the marketplace would be those whose financial (not social) costs were the lowest. Using revenue from these surcharges to fund DSM would solve the first problem; modulating them to reflect the differing externalities of differing production technologies would solve the second. That is, producers using highly polluting and unsustainable technologies would have a higher surcharge added to the price of their product than would those using clean renewables; the result would be that the price advantage of socially undesirable generating technologies would be cancelled out. However, it may be argued that, in practice, it is unlikely that such a surcharge would be of sufficient magnitude to account for the social costs of non-renewable and non-sustainable energy resources.

C. Public Participation

The public participation ethic is widespread in British Columbia. Consultations take place on a broad scale regarding all kinds governmental and non-governmental decisions. With respect to energy, the most wide-ranging consultations were those of the B.C. Energy Council; these gave rise to a broad set of policy recommendations regarding long-term energy sustainability. Indeed, public consultations were a key element in the Energy Council's mandate.

The functioning of the B.C. Utilities Commission also involves the public, though in a much more restrained and formal way. As described earlier, the Commission's hearings are for the most part quite formal. In its special hearings, such as those on the Kemano Completion Project, Commission procedures are somewhat more relaxed and, if, as many suspect, part of the now-defunct Energy Council's mandate is transferred to the Utilities Commission, we may perhaps expect to see it "let its hair down" even more.

A key issue in public participation is participant funding. While no one expects to be paid to come and tell a commission what they think, community and public interest groups cannot participate in on-going planning processes to the extent and with the degree of rigour and responsibility now expected of them without funding. Funding was available for participants in the Energy Council deliberations. As noted below, the Utilities Commission also provides participant funding, but in a manner that some groups regard as inadequate.

As for public participation in the integrated resource planning *per se*, the unbending insistence of the Utilities Commission that representatives of the public actually be involved in each stage of the development of an IRP is starting to show effects. Following the first round of actual IRPs by the province's major utilities, the results are mixed. West Kootenay Power's IRP did involve the public, though in ways that were not entirely satisfactory. As for B.C. Gas, its consultative group was seen as a good first start; expectations are high that in the next round it will do better, especially with respect to the social costing process.

The biggest problem to date has been with B.C. Hydro, but not because it does not consult. In the year prior to its last hearing, B.C. Hydro actually carried out more than 40 distinct consultation processes, relating to projects across the province. However, the Utilities Commission was categorical in stating that these project-oriented, piecemeal consultations do not fulfill the fundamental requirement of IRP that the public be involved throughout the planning process.

From 1991 to 1994, B.C. Hydro sponsored a collaborative process (discussed earlier) to evaluate B.C.'s energy conservation potential, which was extremely successful. This collaborative differed from B.C. Hydro's project-based consultations primarily in that it was directed by the participants, not by the utility, and that it made all its own process-related decisions. The Utilities Commission has directed B.C. Hydro to establish a consultative committee similar in composition to this collaborative, which will participate in each step of its IRP process.[105]

D. Planning under Uncertainty

Uncertainty and risk are dealt with within the IRP process mandated by the B.C. Utilities Commission. Its Guidelines require the development of a range of plausible load forecasts, and more important, the development of resource portfolios for each one of these forecasts. In theory, it is the set of these portfolios that actually is the IRP.

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[105]It is interesting to note that the advisory group to Hydro-Québec's consultative process also recommended the use of a collaborative process — a suggestion that was rejected by the utility. *Avis des membres du Groupe-conseil sur le processus provincial de participation publique au plan de développement 1996 d'Hydro-Québec* (November 1993), pp. 16-17.

In practice, uncertainty and risk do not seem to have played as prominent a role in the IRPs that have been presented to the Commission as might be expected. While risk assessment and robustness remain important concepts in the Commission's deliberations, planning still seems to take place primarily in terms of the “most probable” growth scenario, with other possibilities addressed through sensitivity analysis rather than as the subject of independent analyses. The danger is that such an approach tends to over-emphasize the “medium-growth” scenario, and hence to underestimate the (sizable) likelihood that actual demand growth may in fact be significantly greater or lesser than predicted.

According to Jaccard, the reason is that sensitivy analyses have shown that choosing a higher or lower projected growth rate has little effect on short-term decisions, since planning in B.C. is now dominated by small and short-lead-time resources. If sensitivity analyses were to show that resource planning would change dramatically under the low or high load-growth scenario, however, the Commission would probably insist on the development of separate plans for each.

VII. PLANNING AND REGULATORY AGENCIES IN BRITISH COLUMBIA: A CRITICAL ANALYSIS

A. The B.C. Utilities Commission

The Utilities Commission is in many ways the centerpiece to the energy planning and regulation system in British Columbia, and the piece that makes the others work. Interviews with representatives of regulated utilities and of many of the principal intervenors, from all sectors, demonstrated a remarkable degree of unanimity in their support for the Utilities Commission — both for its mandate and for the decisions its has made in carrying it out. Even from those sectors which one would expect to resent a tough and activist regulator — the utilities themselves and their industrial clients — the Utilities Commission appears to have won the respect of these parties, and is seen by them as a fair broker of their divergent interests. In the words of R. Brian Wallace, who often represents industrial interests before the Commission, “We are there because we believe that if we say something that is right, the Utilities Commission will do something about it.” Wallace is not a “true believer” in IRP, but he is convinced that it is contributing to improving B.C. Hydro's planning. “If it takes IRP for the Utilities Commission to lay out guidelines for B.C. Hydro's planning, I'm all for it,” he said.

In an interview, Ken Spafford, Manager of Resource Planning and B.C. Hydro's main spokesperson on IRP, spoke of the checks and balances created by the oversight structure as a “healthy tension.” Spafford sees the independent review of the appropriateness of expenditures carried out by the Commission to be very desirable, “and it is the only forum for interveners to get into that type of detail.” As for the IRP Guidelines, while B.C. Hydro feels that the Commission has no legislative authority to appprove or reject an IRP, it is very favourable about the process itself. “Before, at revenue requirement hearings, intervener groups always wanted to talk about our resource plans, but resource plans are strictly irrelevant to revenue requirements,” said Spafford. “The IRP Guidelines created a forum for a structured discussion about resource acquisitions. Public consultation alone clearly is not adequate to deal with this issue. There is no replacement for a quasi-judicial review.” Thus, B.C. Hydro appears to acknowledge that a full airing of the issues concerning energy planning ultimately serves its own interests as much as those of interveners.

An important feature of this structure is the arm's-length relationship between both the Utilities Commission and the government. According to Deborah Emes, head of Strategic Services at the Utilities Commission, “having an arms' length regulator ensures that decisions are transparent, and this leads to better decisions. For instance, if the government really wanted to see Site C built, it would have to issue a Special Direction, and would have to take the heat for it. But the Commission also provides a benefit to the government, in that it relieves it of having to make unpopular decisions. To those who want to pressure it into proceeding with an ill-advised project, it can always respond, ‘We wanted to build it, but the Utilities Commission said no.'”

Spafford agreed, noting that the arm's-length structure forces the government to make its agenda explicit. Thus, when the government decided to increase its revenues from B.C. Hydro, it issued a Special Direction to the Utilities Commission, requiring it to set rates at a level which would allow the Crown utility to turn a profit equivalent to what it would be earning if it were a private utility. The decision was criticized by some, defended by others — but because of the Commission's arm's-length, independent role, the government had to lay its cards on the table.

Multiple roles

As we have seen, the B.C. Utilities Commission actually carries out a complex mix of mandates. Are these separable? Are they all essential, and, if so, is it essential that they be linked together as they are under the *Utilities Commission Act*? As noted earlier, the statutory mandates of the Utilities Commission are:

- to regulate the rates of all provincial utilities,
- to review applications for permits for the construction and operation of energy projects,
- to review applications for energy removal certificates, required for energy exports, and
- to hold hearings and make recommendations on questions referred to it by Cabinet.

To this list must be added a fifth role, that is, to oversee the preparation of integrated resource plans by all provincial utilities. Legally, this is understood as an extension of its mandate to regulate rates. In practice, IRP review is usually addressed in the context of a rate review, though in some cases it has been separated out into a separate hearing.

The biggest question, and the most important one from a practical point of view in trying to imagine the application of such a system in Québec, is the advisability of maintaining this connection. Is IRP inherently associated with rate regulation, or is that association in B.C. an artefact of the historical evolution of the Utilities Commission?

It certainly is not unreasonable to associate IRP with rate regulation, which has been applied to all utilities in B.C. since 1980. As noted above (p. 25), IRP, or something like it, is necessary to permit a regulator to assess the prudency of capital investments before they are a *fait accompli*. But while the two often go together, examples can be found where they did not. To start with the obvious one, rate regulation without IRP existed in B.C. until the Utilities Commission IRP Guidelines were issued in 1992. This proves little, however, since it was precisely the inadequacies of the earlier structure that led to the Guidelines.

A more interesting example is that of the (American) Northwest Power Planning Council, widely seen as the birthplace of IRP. The NPPC is not and has never been a regulatory body, in that it has no responsibility or control over rates. Rather, its sole function is in planning: it prepares long-term plans, and reviews the resource plans of all the utilities in the four-state region it covers.

As such, the NPPC's sole legal power with the individual utilities is one of persuasion, not of control.[106] However, it does have considerable informal power. The Council's plans are very thorough, and, since the members are representatives of the four State Governors, it has quite a bit of clout. In fact, according to James W. Litchfield, who was head of planning for the NPPC from 1981 to 1992, the Public Utility Commissions and other types of regulators in the four-state area make considerable use of the the Council's Plan and its expertise in their own deliberations.

In fact, the NPPC does not replace the application of IRP by state regulators, but it supplements it. In each of the four states, the Public Utility Commission requires the utilities under its control to carry out IRP, following guidelines very similar to those of the NPPC. The Council thus functions in part as a model and guide for utility IRPs, in part as an expert resource in PUC hearings. It also serves the role of “big-picture” planning: while each utility performs IRP with respect to its own service area, it is only the NPPC that can stand back and look at the combined effects of actions being taken throughout the region.

In other words, each PUC exercises a function very similar to that of the B.C. Utilities Commission, with rate regulation and IRP together. In addition, the NPPC exercises a regional planning mandate, providing leadership and supplementing, but not replacing, Commission-mandated IRP.

In Québec, a strong consensus has been reached on the importance of IRP, but less emphasis has been placed on the issue of rate regulation. Is it possible, and is it desirable, to have one without the other? Most of the key players in British Columbia interviewed in the course of this research were of the view that it is not. Many reasons were given, but the most pervasive was simply that it is only through rate regulation that the Commission can control a utility, especially a powerful Crown utility. Aside from punitive legal sanctions, which have never been used in B.C., the most important power the Utilities Commission has over the utilities is its power to refuse their requests for a rate increase. This is no trivial power: in controlling the flow of revenues to the utility, the Commission can in fact insist that its IRP requirements be followed. Without this stick, most observers felt that the Commission would be nothing more than an irritant to a utility that did not want to follow its lead. Its planning requirements would thus become voluntary, not mandatory.

Bringing together IRP and rate regulation under a single roof serves another important purpose. Rate regulation is by its nature highly detailed and technical, and thus requires a strong professional staff. IRP also requires a strong staff, though one can imagine implementations of IRP which remain more qualitative and superficial. Fusing the two roles in a single body in effect ensures that the IRP exercise will not be trivialized.

The same may be said for the licensing roles, both with respect to energy projects and exports. Once

[106] There is one exception: the Bonneville Power Administration, which is federally owned and the largest power producer in the region, cannot build a new resource greater than 50 MW without Council approval.

a strong technical staff has been created, it seems only logical to make it available for these other types of regulatory approvals.

Procedures

Another question that must be resolved in the implementation of an regulatory structure concerns procedures. In Québec, there is a widespread belief that quasi-judicial processes are undesirable because of their formality and expense. Perhaps surprisingly, most observers in B.C. strongly defend its relatively formal way of functioning, with testimony under oath and cross-examination of witnesses by interveners, or more often by their legal counsel.

Furthermore, public hearings may be of value for the utility itself. “Public hearings focus the minds of utility management far more than do consultation processes,” said Brian Wallace. “The preparation of top management for public hearings is the most productive time they ever spend. The CEO says to his staff, ‘tell me every embarrassing thing that could possible come up, *now*. If I get caught on something you haven't warned me about, you're gone.'”

Interestingly enough, the public interest groups were equally enthusiastic about the quasi-legal approach. Despite the expense of working with lawyers, they vigorously defend the importance of doing so. Groups interviewed were virtually unanimous in the view that, without legal counsel and cross-examination, the exercise would quickly become meaningless. It was noted by several parties that interveners who did not have legal counsel were often unable to get clear and straightforward answers from a skilled witness, even when they participated effectively in the proceedings. “Cross-examination is absolutely essential,” said Dermot Foley of the B.C. Energy Coalition. “Otherwise, there's nothing to stop you from getting brushed off. It is not essential to have a lawyer, but it helps a lot. They are trained to focus their questioning to build an argument, and to insist on getting their questions answered.”

The one point where the public interest groups are not satisfied is with the process used to provide funding to them to support their participation. The Utilities Commission doesn't provide any funding for preparatory work, but only for actual hearing days. As noted earlier, funding is only awarded at the end of a hearing, and is based in part on the Commission's judgement of how valuable the group has been to its deliberations. For small public interest groups, this means that they must decide how much effort to invest in a hearing (counsel, expert witnesses) without knowing whether or not the expenses will be reimbursed. “The Utilities Commission claims to care a lot about the informed public actively participating, but it makes it almost impossible to do so,” said one intervener. Another intervener, the Public Interest Advocacy Centre, has sued the Commission for what it considers an inadequate cost award.

B. The B.C. Energy Council

Any critical evaluation of the achievements and failings of the B.C. Energy Council must take place in the context of the government's decision to terminate its mandate. Though it was originally meant to be a permanent body, the B.C. Energy Council's mandate was terminated as of the end of November 1994, after two years of existence.

In addition to preparing the Energy Strategy described above, the Council also carried out a public consultation concerning long-term firm exports. This was in fact the first task to which it turned upon its creation, and, as we shall see, many observers feel that this consultation was inextricably linked to the Council's demise, though there are different interpretations as to how.

As noted earlier, work on the Council's primary mandate, the energy strategy, was delayed until after it completed its export review in April 1993. The first discussion paper on the energy strategy was not released until June 1993, and the draft report was not released until June 1994. This had two important consequences. First, it meant that, when the provincial budget was being prepared in March 1994, the Council still had nothing to show for a year of work on its primary mandate. Thus, some observers argue that, had it not been for the export review, the draft strategy would have come out much earlier, and the resulting awareness of the Council's accomplishments would have ensured its continued existence.

Criticism of the Energy Council seems to have been harshest among the utilities — who paid for its activities through a levy on their sales — and their industrial clients. Members of these groups expressed the views that the Council was redundant to the other planning bodies in British Columbia, and, perhaps more important, that the consultative approach taken by the Council was too long, too expensive and ultimately wasteful. One industrial spokesperson described the Council's approach as being one which measured the success of its consultative efforts on how many people it heard from, rather than on the value of what they had to say.

This view was not shared by other stakeholders, however. The Council got high marks from many observers, both inside and outside governmental and regulatory bodies, for taking its consultative mandate seriously. As well, there seems to be a fairly broad consensus that the Energy Council fulfilled a necessary function, in seeking a long-term perspective on energy sustainability — very different from the hand's-on approach of the Utilities Commission or the policy role of the Ministry of Energy, Mines and Petroleum Resources.

Some of the public interest groups have a different take on demise of the B.C. Energy Council. According to this admittedly cynical view, what the government really wanted from the Council was its report on electricity exports, which paved the way for a provincial policy that permitted such exports with only minor restrictions. Having gotten what it needed, the government then pulled the plug.

A more mainstream view also sees the demise of the B.C. Energy Council as based on political factors. According to this view, the Council's termination was a fluke that was due less to redundancy, irrelevance or inherent flaws in its structure than to the political conjuncture in which it found itself, with a left-wing government dogged mercilessly by a right-wing press. A creation of the NDP government and chaired by a former NDP candidate, the Council had the press against it from the start. For this reason, the Minister felt obliged to give it a high-profile mandate in order to get it through Cabinet; this, then, was the political justification for the export policy review. But the export review, necessary to ensure the Council's creation, was also its downfall: instead of taking the time necessary to get the institution up and running, to build a staff and to develop credibility among the key stakeholders, the Council was thrust into a high-profile, controversial review before it was ready. In the process, it lost considerable credibility with the public interest groups, and as a result had a much harder time building consensus around its core mandate, the long-term sustainable energy strategy.

It is not entirely clear who will pick up the ball from the B.C. Energy Council. In terminating the Council, the government indicated that MEMPR and the B.C. Utilities Commission would each perform some of the Council's functions. In its report, the Council made a number of recommendations on this matter. It suggested that the strategy needs to be updated at two- to three-year intervals, to keep pace with rapidly changing energy markets and technologies. Responsibility for seeing that updates are done rests with MEMPR, but the Council suggests that it may be preferable for the review to actually be carried out by an arm's length agency, in part because it is the Ministry is responsible for implementing the strategy, and in part because the questions raised extend into the territory of other ministries. Thus, it would be required “that the Ministry receive a clear mandate to enhance its ability to work with other ministries, with other levels of government, with business, environmental and other public interest groups and with the general public.”[107]

It seems clear that at least some of the Council's functions will be transferred to the B.C. Utilities Commission. The Council noted that that the Commission already has the authority to implement many of the Council's ideas, and it recommended that the Commission's IRP initiative be broadened to allow it to integrate the plans of the various utilities. As for the Council's role in examining specific energy issues, this is already part of the Commission's mandate, though the processes of the two bodies are very different. The Commission's quasi-judicial procedures make it much more formal than the Council's wide-ranging public consultation; while these procedures serve it well for some issues, they may limit its ability to sound the public in a more general way.

It was remarked earlier that there is a tension at the Utilities Commission between openness and formality. Some feel that hearing time is too valuable to continue to give members of the general public standing to participate as full interveners, with rights to cross-examine every witness. Folding the Council's mandate for broad public consultation into the Utilities Commission could aggravate these difficulties.

However, Commission chair Mark Jaccard is confident that the Utilities Commission can comfortably

[107]*Planning Today for Tomorrow's Energy*, p. 149.

play this advisory role. In the past, the Commission has issued discussion papers and held public sessions on general energy issues. Now, in the review of competition and wheeling policies discussed earlier, it will rely heavily on workshops, panels, town hall meetings, synthesis papers by Commission staff, and other mechanisms.

“While we will eventually end up in formal hearings, we will try to stay away from that format as long as possible,” says Jaccard. He is convinced that people are in fact more interested in participating in Commission consultative processes than in those held by purely advisory bodies. “People are very keen on our processes, because they realize that they can actually lead to decisions,” he said.

C. The Crown Corporations Secretariat

As noted earlier, it seems clear that the Crown Corporations Secretariat has played a useful role in British Columbia. Whether or not is an essential role, or one that should be emulated, is another question. In an interview, Ken Peterson, who handled energy issues for the CCS, acknowledged that the energy portfolio in B.C. is in a sense “over-determined,” but he did not see any conflict of mandate between the CCS and the Utilities Commission. “The Utilities Commission is much more reactive than we are, in that it responds to applications,” he said. “Under Mark Jaccard, it has taken a very active role, particularly with its IRP Guidelines, which we think are excellent. But the Commission's approach to receiving, reviewing and hearing is much more deliberate and public than ours, and corresponds much less to the direct management role that the governemnt may sometimes wants to employ in relation to its biggest assets.”

According to Peterson, the CCS was never meant to be a permanent body. “We definitely cut into the Crowns' territory, so this kind of an agency is by nature very short-lived,” he said. “To be able to do it effectively, you've got to annoy a lot of people, and pretty soon, they get even with you. The alternative is a bureaucratic approach like that of the Crown Investments Corporation in Saskatchewan, which is a holding company of all the Crowns. It is a permanent structure, with significant bureaucracy. That's not a bad way to go either, if you can get a quick response, but it's very hard to get people in large institutions to think about their business in a different way. The feel like they are successful in what they are doing, so why should they change? You really have to whack 'em every once in a while to get them to think about things differently.”

Even if it ends up being short-lived, the CCS can take credit for significant improvements in the functioning of many of the Crowns, including BC Transit, BC Ferries and BC Rail, as well as BC Hydro. In its first year of functioning, with a budget of just over $2 million, it had achieved almost $200 million in actual savings, and estimated the future benefits of actions undertaken at close to $1 billion.

D. Environmental Assessment of Energy Projects

While it is not usually considered to be part of the energy oversight process, environmental assessment does plays a key role in the ultimate approval of energy projects. The reform currently underway in B.C. is of considerable interest precisely because it brings these two aspects of energy resource planning into a much closer relationship.

Under the existing system in Québec and elsewhere in Canada, the two processes are separate, and are under the responsibilities of two separate Ministries. Under this system, each energy producer carries out its own planning procedure — with or without public involvement, and with or without supervision by public agencies. When an energy producer chooses to proceed with a project, it is submitted for governmental authorizations which, depending on the size and nature of the project, may require a public environmental assessment process. For projects in southern Québec, this is carried out by the Bureau des audiences publiques sur l'environnement (BAPE); for projects in the territory governed by the James Bay and Northern Québec Agreement, it is carried out by the committees created therein.

In the context of such environmental assessments, the question of project justification has assumed considerable importance. The report of the BAPE hearings on the Sainte-Marguerite project — the most recent large hydroelectric project to be undertaken in Québec — raised significant questions as to the project's justification. The question occupied a major place as well in the environmental assessment of the Great Whale hydroelectric project, which was recently suspended. In effect, in the absence of a transparent and credible public *planning* process, environmental panels have little choice but to reflect in depth on whether or not the proposed project is the best solution, from a societal point of view, to projected energy needs. This was precisely the situation in B.C. in the Revelstoke hearings in 1976, when, for exactly the same reasons, the Water Comptroller agreed to hear argument on project justification despite the fact that it was beyond his explicit mandate.

The reform of environmental assessment (EA) procedures now underway in B.C. suggests a possible resolution to this fundamental problem. Evidently, EA procedures vary enormously from one jurisdiction to another, and it would make no sense to try to directly import the B.C. formula to Québec, but the basic concept is of great interest. Its essential elements are:

- that prior approval in a public IRP process be an essential requirement before a project can be submitted for EA, and

- that, once the environmental and social impacts of the project have been carefully evaluated in the EA process, the file is returned to the energy planning body to ensure that it is *still* the best choice, taking into account the detailed information on its impacts that has emerged from the EA process as well as an updated analysis of energy needs and alternatives.

Such an approach would greatly simplify environmental assessment — in removing project justification from its domain — and it would also save time and money from beleaguered Environment Ministries by reducing the number of projects submitted for evaluation.

However, for such an approach to be credible, it would have to be based on an IRP process which is strong, transparent and independent. Even in B.C., which has undertaken the changes described in this paper at an extraordinary pace, this step was not taken until the Utilities Commission had been in place for 14 years, and had been requiring IRP for two years. To attemp this kind of restructuring before the IRP/regulatory process is mature would be to invite disaster.

E. Essential Features

British Columbia offers much food for thought in reflecting on possible institutional structures for Québec. While the wisdom of the choices it embodies with respect to individual agencies and their mandates is open to debate, the B.C. model clearly shows the advantages of distinguishing fundamentally different elements of energy planning and regulation, and of entrusting them to bodies of different structures and mandates. One of the first questions that needs to be addressed is, which parts of the existing regime in B.C. are "essential" — that is, which ones represent the implementation of a clear philosophy of energy planning and regulation — and which are the consequences of particular situations or historical antecedents which are unique to British Columbia?

1. The Crown Corporations Secretariat: Liaison with the Crown utility

Of the three bodies discussed in this report, it seems clear that the Crown Corporations Secretariat is not essential, in the sense described above. This does not mean that it is not an excellent tool for improving the performance and accountability of B.C.'s Crown corporations, or even that it might not be interesting for Québec to consider this approach to managing its para-governmental bodies. However, its existence and its mandate have emerged from the general issues relating to government control over Crown Corporations, and are only incidentally related to energy policy.

With regard more specifically to the role of the CCS with respect to B.C. Hydro, there are elements that may be of value to retain. It is widely known that relations between the government and Hydro-Québec are not always smooth. It is not always clear which choices belong to the utility, and which to the government.[108] Situations arise in which the government is accused of meddling in the affairs of Hydro-Québec, or conversely, situations where Hydro-Québec is seen as "out of control." Thus, while such a body is in no way essential for the implementation of IRP, it may be interesting to look

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[108] Signs of friction or of incomplete communication between the Crown corporation and its sole shareholder include incidents such as Energy Minister Lise Bacon's public efforts to force Hydro-Québec to sign certain cogeneration contracts in 1992, Premier Daniel Johnson's announcement of the Ste-Marguerite hydro project on the same day that Hydro-Québec announced major reductions in its load forecasts, and of course Premier Parizeau's announcement of the suspension of the Great Whale project in November 1994, which apparently took Hydro-Québec by surprise.

more closely at the CCS as one possible approach to normalizing and improving the relationship between Hydro-Québec and the government.

2. The B.C. Energy Council: Long-term planning on a societal level

While government departments are normally responsible for planning and policy, situations arise where a broader view, and one which is at arm's length from the government, is required. British Columbia found itself in this situation in 1980, when it launched the process that led to the adoption of the *Utilities Commission Act*, and again in the early 1990s, when it established the B.C. Energy Council.

Policy development in B.C. continues to rest with the Ministry of Energy, Mines and Petroleum Resources, but it is now supported by the results of the deliberations of the Energy Council, which were based in turn on very extensive public consultations. As noted earlier, an inter-ministerial committee has been established to address the complex issues raised in its report.

If there is an interest in creating institutions such as these in Québec, many questions will have to be addressed. To start with, decisions would have to be made as to whether or not these roles should be grouped together in a single body. One approach is for resource planning, regulation and consultation to be the responsibility of a single body. This is the direction that B.C. appears to be heading, since the disbandement of the Energy Council, with all three of these roles carried out by the B.C. Utilities Commission. This is not the only possible structure, however. Another possibility would be to entrust integrated resource planning, both on a utility level and on a wider regional or societal level to one body, and rate regulation to another. The pros and cons of these alternate arrangements need to be examined in detail.

As for the British Columbia Energy Council, such a body may not be essential as a permanent structure, though its importance should not be minimized. The setting of long-term goals through a very public process is an admirable and probably a necessary process. Key characteristics of the Energy Council were its independence from the government, its mandate to base its recommendations on extensive consultation with the public, and the relatively long timeframe of its mandate (18 months for the preparation of its energy strategy).

In effect, the role played by the Energy Council in B.C. may well turn out to be that of the Public Debate on Energy in Québec. While the modalities of that process have not yet been announced as of this writing, there may well be a considerable similarity between these two processes, in that both are intended to privde broad public input into long-term energy policy. While the Energy Council was at first intended to be a permanent body, its mandate was terminated after being in existence for two years.

3. The B.C. Utilities Commission: Regulation and planning

Finally, there is the British Columbia Utilities Commission. As noted earlier, the Utilities Commission is in a sense the centerpiece to the energy planning and regulation system in British Columbia. This is perhaps curious, because the Utilities Commission is in many ways an unlikely creation. As noted by Mark Jaccard in an article cited earlier, the natural monopoly and public good characteristics of the electricity market have led Canadian governments to intervene either through regulation or through public ownership of generating resources, but not both. Most of the provinces which rely heavily on capital-intensive hydro or nuclear technologies have Crown electric utilities which are not directly regulated.

Jaccard points to two problems with the public ownership model:

> "The first relates to the economic inefficiency that may result when political concerns and the self-interest of utility managers interfere in investment and operating decisions. The second relates to the problems for democratic societies from the concentration of power in the hands of managers of large publicly owned corporations."[109]

These problems can be thought of as a "principal-agent" problem. "According to this concept, the publicly owned corporation is an agent of government assigned to meet the government's objectives. However, the agent may have different objectives than government and as a result may frustrate or at least fail to achieve the latter's objectives."[110]

This, for Jaccard, is the justification for grafting a regulatory apparatus onto the public ownership model:

> "In the late 1970s, British Columbia Hydro was increasingly criticized for planning large hydroelectric projects throughout the province without fairly evaluating financial and environmental risks, smaller scale supply opportunities, and energy efficiency alternatives. The largest and most criticial investment decisions in the province were being made by a group of technicians and bureaucrats, with virtually no opportunity for public input or review. Mounting public concern that the 'agent' was not at all serving the interests of the 'principal' convinced the government to place its publicly owned utility under the regulatory control of the provincial public utility commission. This created the somewhat unique situation in which a publicly owned utility was created to address the natural monopoly and public good failures, while the layer of utility commission regulatory control was added to address the principal-agent problems of publicly owned corporations. In spite of its unconventional design, this institutional model has proven to be very successful compared to other Canadian jurisdictions."[111]

Thus regulation is in fact in no way incompatible with public ownership. As the B.C. experience demonstrates, the application of a regulatory regime to a Crown utility offers considerable benefits, with respect both to transparence and public accountability, on the one hand, and to the quality and integrity of the energy planning process *per se*, on the other. While public ownership serves important goals, it is not in itself adequate to ensure that societal priorities are reflected in energy choices.

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[109]Jaccard, *op. cit.*, p. 4.

[110]*Ibid.*, p. 15.

[111]*Ibid.*

While there are many possible structures that could accomplish these goals, a number of elements appear to be necessary. The principle ones are the following:

- ***Regulation of rates and revenue requirements***

  As we have seen, there are several reasons why utilities are regulated, including their monopoly status and the impacts their activities have on third parties. In addition to the capital spending focus of IRP, most jurisdictions have considered it essential to regulate the rates of utilities in order to protect customers' interests, since utilities are shielded from competitive pressures by their monopoly status. Even when the utility is publicly owned, a strong argument can be made that such regulation imposes greater discipline on the utility with respect to its expenditures, and greater transparence as well, which leads to increased public confidence.

  The B.C. Utilities Commission has a clear and unequivocal mandate to regulate the rates and revenue requirements of all utilities in B.C., including B.C. Hydro, a Crown corporation. The B.C. experience has shown that rate regulation of a Crown utility is not only feasible, but in many ways desirable.

- ***Integrated resource planning***

  It is now clear that integrated resource planning is a powerful tool for ensuring that capital expenditures for energy resources are made in the best interest of society at large. In many jurisdictions, IRP is carried out by individual utilities under the mandatory control of a Utilities Commission. As well, some jurisdictions have also implemented regional integrated resource planning in order to achieve a greater coordination between the actions of different players in the energy sector. Such regional IRP can be done on an electricity-only or on an inter-fuel basis.
  In B.C., IRP is carried out by each utility under the overview of the B.C. Utilities Commission. At the same time, the Utilities Commission appears to be moving toward regional (inter-utility and inter-fuel) IRP processes as well, following in part the recommendations of the B.C. Energy Council. However, it has no explicit mandate to do so, and the mechanisms under which such processes would take place have not been fully elaborated.

On a slightly more distant horizon, there is concern that coming changes in the electric industry — the separation of generation, transmission and distribution components (vertical de-integration) and the gradual introduction of competitive generation markets, whether wholesale or retail — could substantially reduce the role both of the utilities and of their regulators in determining which facilities will be built. Such developments could also substantially weaken the role of environmental assessment processes, since competitive markets often favour small projects that are exempt from public review. Alternatives such as watershed and airshed management have begun to be discussed. These questions are only now coming to the fore in the deliberations of the B.C. Utilities Commission and other policy and advisory bodies.

F. Conclusions

The oversight and planning process for energy in British Columbia can be broken down into three main elements: energy policy, rate regulation and resource planning.

Energy policy

The development of energy policy can be broken down in turn into three distinct parts:

- long-term "visionary" planning, the role of the B.C. Energy Council. Its purpose was not to create policy or to implement it, but to sound the public and attempt to set out the broad lines of an *approach* to energy policy which, over the long term, would meet the economic, environmental and social goals of the population;

- public consultation with respect to specific elements of energy policy. Both the Energy Council and the Utilities Commission provide recommendations on policy matters, consulting the public directly and at arm's length from the government;

- development of energy policy itself. This remains the domain of the government, through the Ministry of Energy, Mines and Petroleum Resources. Ministry policies form the basis for choices both of B.C. Hydro and of the Utilities Commission;[112] the Ministry is also involved in the preparation of Special Directions to both the utility and the Commission, which are mandatory and binding.

Rate regulation

Detailed economic regulation of the province's utilities is the exclusive domain of the B.C. Utilities Commission, which has all the powers of an administrative tribunal to enforce its decisions.

Resource planning

Energy resource planning is a complex process that leads to the choice of new energy resources, which can include generating and transmission equipment as well as demand-side management programs or purchases. The process includes three major elements:

- the development of resource plans, now done through an IRP process under the oversight of the B.C. Utilities Commission. As well, the capital investment policies of B.C. Hydro is overseen by the Crown Corporations Secretariat.

- environmental assessment. While environmental assessment is often considered to be a separate process, no major energy projects can be built without environmental authorizations. Under the new Environmental Assessment Act, there is a close relationship between this process and the IRP process of the Utilities Commission.

[112]See for instance recent policy statements on electricity exports and on purchases from IPPs.

- licensing and authorization of energy projects. This responsibility is divided: for minor projects, it is the exclusive jurisdiction of the Utilities Commission. For major projects, however, the final decision still rests with Cabinet.

Over the last 15 years British Columbia has experimented with a variety of structures to implement these planning and regulatory concepts. These elements are summarized in the following table. In a final column, it also describes the way these issues are handled in Québec at this time.

<table>
<tr><th rowspan="2"></th><th colspan="4">BRITISH COLUMBIA</th><th rowspan="2">QUÉBEC</th></tr>
<tr><th>PRE-1980</th><th>1980-1992</th><th>1992-1994</th><th>1995-</th></tr>
<tr><td>ENERGY POLICY</td><td colspan="2">Ministry</td><td>Ministry, with advice from Energy Council and Utilities Commission</td><td>Ministry, with advice from Utilities Commission</td><td>Ministry</td></tr>
<tr><td>RATES</td><td>Regulated for private utilities, B.C. Hydro rates set by Cabinet</td><td colspan="3">Rates for all utilities, including B.C. Hydro, set by Utilities Commission</td><td>Hydro-Québec rates set by Cabinet; gas utilities' rates set by Régie du gaz</td></tr>
<tr><td>RESOURCE PLANS</td><td colspan="2">Budgets for private utilities approved by Utilities Commission; B.C. Hydro's Development Plans approved by Cabinet</td><td colspan="2">IRP required by Utilities Commission</td><td>Hydro-Québec's Development Plans approved by Cabinet</td></tr>
<tr><td>ENVIRONMENTAL ASSESSMENT</td><td>Hearings by Water Comptroller (for hydro projects only) (justification and impacts)</td><td colspan="2">Hearings by Utilities Commission (justification and impacts)</td><td>Prior approval in IRP required; hearings by Environmental Board (impacts only)</td><td>Hearings by BAPE or JBNQA committees (justification and impacts)</td></tr>
<tr><td>EXPORT AND CONSTRUCTION PERMITS</td><td>Cabinet</td><td colspan="3">Utilities Commission (Cabinet approval for major projects)</td><td>Cabinet</td></tr>
</table>

With respect to energy policy, actual policy development has always remained with the Ministry of Energy, Mines and Petroleum and Resources, as it resides in Québec with the Ministère des Ressources naturelles. However, from 1992 to 1994, the Ministry received advice both with respect to particular policy issues and with respect to long term planning for sustainability from the B.C.

Energy Council. With the termination the Energy Council's mandate at the end of 1994, it appears that this mandate will for the most part be shifted to the B.C. Utilities Commission. A new non-governmental organization, the Sustainability Council, may also play some role in ongoing reflections on long-term energy choices.

As for ratemaking, until 1980 B.C.'s structure was similar to that now in effect in Québec: rates charged by private utilities were set by a provincial regulatory body, while the Crown electric utility's rates were set directly by Cabinet. That structure was changed in 1980 by the *Utilities Commission Act* — a change which has had profound repercussions on energy planning in B.C. The Utilities Commission created by that Act, which has full regulatory control over B.C. Hydro (except for its bond issues, which are controlled directly by the government), has been the driving force behind many of the changes that have taken place since.

The most important of these changes concern capital spending — major investments in energy resources. Even after 1980, the only way the Utilities Commission could influence capital spending was through its oversight of capital spending budgets. This was an important control, but it did not permit it to fully assess the basis on which capital projects were selected. It was only with the promulgation of the Commission's Integrated Resource Planning Guidelines in 1992 that it began to play an major role in overseeing fundamental energy choices, based on a rigorous comparison of all the options. It should be noted that the legislative authority under which these Guidelines were issued was still the Utilities Commission Act of 1980, which makes no explicit mention of IRP. While there appears to be no move underway at this time to revise the Act, if it were written today, it would almost certainly spell out the Commission's role in IRP.

One of the primary benefits of this IRP process, noted by interveners, Commission staff and utilities as well, is that it provides a public forum for a careful examination of the choices leading up to the decision to develop a major energy resource. In so doing, it has both improved the rigour of resource planning and significantly reduced the level of public controversy surrounding such plans.

Since the late 1970s, the principle has been widely accepted that, before a major energy resource can be developed, there must be some kind of public environmental assessment process. Until 1980, the only mechanism for such hearings in B.C. was under the Water Act, which only affected hydroelectric projects. These hearings were meant to address environmental impacts only; however, in the landmark Revelstoke hearings of 1976, project justification for the first time appeared as a major issue in the hearings. Since 1980, under the *Utilities Commission Act*, such hearings were held by the Utilities Commission, which had a mandate to address both justification and environmental issues. As in Québec, these hearings were lengthy and complex affairs.

In an attempt to improve on this situation, a new system has been passed into law, but not yet proclaimed. Under the *Environmental Assessment Act of 1994*, energy projects are not even allowed to apply for environmental permits unless they are part of an IRP which has already been approved by the Utilities Commission. Thus these hearings, which will take place before an Environmental Board, will deal only with environmental issues; since they will already have passed through a rigourous IRP process, there would be no need for the Environmental Board to address project justification.

Finally, to complete the review process for capital spending, this new regime also provides a role for the Utilities Commission after the environmental hearings; if mitigation costs or a changing energy situation have made the project less attractive, it can be reconsidered in light of this new information.

Many of the problems that these structures were designed to meet are still vital and divisive problems in Québec and in many other parts of the world. It will be up to policy makers and the public to find the particular set that is best adapted to the particular characteristics of Québec.