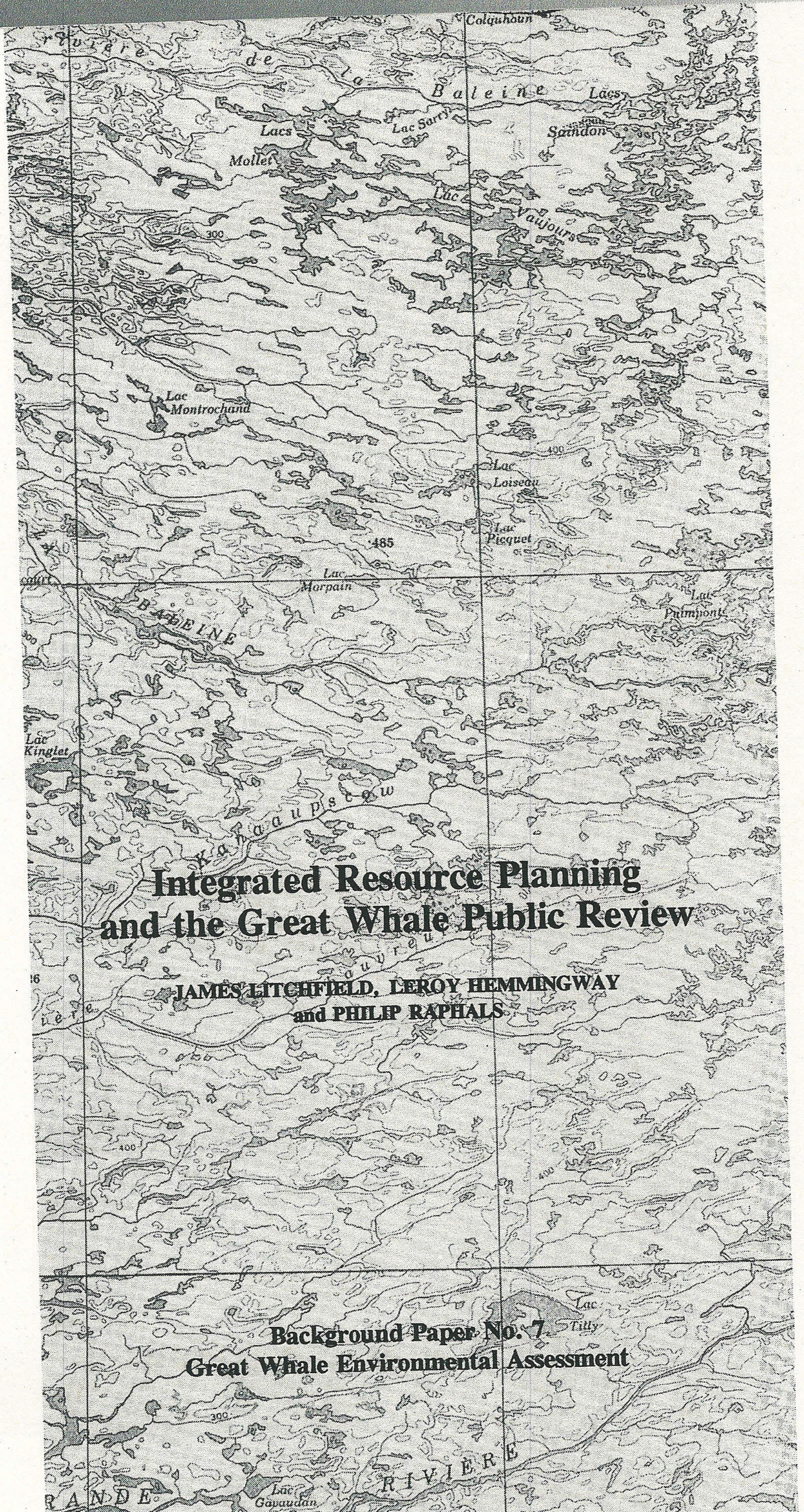

Integrated Resource Planning and the Great Whale Public Review

JAMES LITCHFIELD, LEROY HEMMINGWAY
and PHILIP RAPHALS

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ABSTRACT

This paper reviews the basic concepts of integrated resource planning (IRP) as they have developed in the energy planning field over the last 15 years and their relevance to project justification in the Great Whale Public Review. IRP differs from traditional utility planning in four major ways:

- Load forecasts describe the full range of plausible future energy needs, not just the utility's "best guess" as to the most likely level of future demand. When planning and decision-making processes place inordinate weight on the medium forecast, the impact of load uncertainty on resource decisions is often underestimated or ignored;

- Measures to reduce demand for electricity are considered on an equal footing with new power production resources. This requires that the economic ranking of alternate resources include energy efficiency resources as well as new generating resources;

- Uncertainty and risk are explicitly recognized, both with respect to energy needs and to financial consequences, and strategies are developed to manage uncertainty and minimize risk;

- The environmental and social impacts of various resource strategies are fully integrated into the decision-making process. As long as alternative resources are ranked according to economic criteria alone, neither the criterion of sustainability nor that of least total cost to society can be met.

The paper provides an overview of key IRP concepts and their inter-relationships. It also describes a multi-attribute decision analysis method which could be used to better understand the trade-offs between economic and environmental costs in comparing several resource strategies.

RÉSUMÉ

Ce document porte sur les concepts fondamentaux de la planification intégrée des ressources (PIR) tels qu'ils ont été élaborés au cours des quinze dernières années dans le domaine de la planification énergétique et discute de leur pertinence relativement à la justification du projet dans l'examen public du projet hydroélectrique Grande-Baleine.

La PIR se distingue de la planification traditionnelle des compagnies d'électricité sous quatre rapports fondamentaux, qui sont:

- Les prévisions de la demande, qui décrivent l'éventail complet des futurs besoins énergétiques plausibles, et non seulement «la meilleure approximation» de la demande future la plus vraisemblable. Quand les processus de planification et de prise de décisions accordent un poids démesuré à la prévision moyenne, l'impact de l'incertitude de la demande sur les décisions en matière de ressources est souvent sous-évalué ou ignoré;

- Les mesures visant à réduire la demande d'électricité, qui sont mises sur le même pied que les nouvelles ressources de production d'énergie. Ceci requiert que le classement économique des ressources inclut des ressources d'efficacité énergétique et de nouvelles ressources de production;

SUMMARY

Integrated resource planning (IRP) is the name given not to a single planning methodology but to an evolving approach designed to make sure that utility planning furthers the interest of society as a whole. The purpose of IRP is simple: to provide the energy services required by society at the lowest cost and with the least negative impacts through the systematic analysis of all possible stategies for meeting energy service needs, and taking into account all plausible futures. The emphasis in IRP is on "energy services" rather than on energy *per se*, because it is the services provided by energy, such as heating, lighting, motive power, cooling, computing, etc., that have value to society. Though applied differently in different regions, the basic principles of IRP are widely accepted, and it is now practiced in large parts of the United States and Canada.

While most utilities would describe their traditional planning methodologies as "least-cost", it has become apparent that many significant costs were excluded from this process. Integrated resource planning thus differs from traditional utility planning in four major ways:

- Load forecasts describe the full range of plausible future energy needs, not just the utility's "best guess" as to the most likely level of future demand;

- Measures to reduce demand for electricity are considered on an equal footing with new power production resources;

- Uncertainty and risk are explicitly recognized, both with respect to energy needs and to financial consequences, and strategies must be developed to manage uncertainty and minimize risk;

- The environmental and social impacts of various resource strategies are fully integrated into the decision-making process;

The proposed Great Whale hydroelectric project is widely seen – both by its advocates and by its detractors – as a key issue for Quebec's energy future. A comprehensive environmental review process has been put in place to assess both the need for and the potential impacts of the proposed project, and project justification is a major focus of the Guidelines which set requirements for Hydro-Québec's Environmental Impact Statement.

The fundamental questions of project justification include whether or not there is a need for new generating resources, and whether the best scenario for meeting that need includes the Great Whale project. But to answer these two apparently simple questions, answers must first be found to some very complex ones.

As IRP has evolved over the last 15 years, a series of technically rigorous methodologies have been developed that can provide answers to these kinds of energy planning

questions. The conceptual approach on which these methods are based is to a large extent embedded in the *Guidelines*. The primary goal of this paper is to explain these methodologies and to indicate their relevance to the analysis of project justification.

We address six broad areas of integrated resource planning: load forecasting, the assessment of supply-side (generating facilities) and demand-side (conservation and energy efficiency) resources, resource portfolio analysis, financial analysis, and the assessment of externalities and their incorporation into the planning process.

Load forecasting

In the past, major resource decisions were made on the basis of a forecast of the future considered most likely to occur, corresponding to the so-called "average" scenario. These decisions were inherently very risky, because actual conditions would often differ greatly from the forecasts on which the decisions were based. A planning process that relies on a single forecast ignores the uncertainty that is fundamental to the prediction of future events.

The function of the load forecast in IRP is to set out a *reasonable range* within which loads may vary over the planning period. While some load scenarios are more likely to occur than others, it is essential that the long-term plan be able to respond to all possible futures within this range, not just the one that the forecaster considers to be "most likely".

Supply-side resource assessment

IRP requires a complete assessment of all potential resources, both supply-side (generation) and demand-side (conservation and energy efficiency). The first problem is to compare the costs of resources that vary greatly in their length of service, necessary lead-time, capital costs, fuel costs and operating and maintenance costs. The tool planners usually use to compare these costs is known as "levelized real life-cycle costs"; this same measure can also be used to compare demand-side to supply-side resources.

While levelized real costs are a very useful tool, their limitations must be well understood. Even though the levelized real cost of a new resource may be no greater than today's average system cost, the resource may lead to substantial rate increases when it is commissioned. This rate impact will be proportional to the levelized *nominal* cost of the new resource, which, for capital-intensive resources like hydroelectricity, is about twice as great as the levelized *real* cost.

The financial risks associated with large resources and those with long lead times become apparent when evaluated within an IRP framework. This risk can be evaluated and assessed an economic value. Thus a risk penalty should be assigned to large, long lead-time resources when compared to shorter lead-time, smaller resources.

Demand-side resource assessment

The *Guidelines* in essence require that all demand-side alternatives that can be competitive on both cost and performance with supply-side resources are included in the resource plan. However, demand-side resources pose difficult assessment issues. These involve the determination of the *technical* and the *techno-economic potential*, as well as the expected *penetration rate* -- the percentage of potential users of a particular demand-side measure who are likely to actually implement it, within a given time period. Target penetration rates for large utilities to typically range from 30 to 60 percent of the techno-economic potential over a 10-year period, and from 60 to 90 percent over a 20-year period.

Demand-side programs, while not technically complex, are extremely challenging to design and manage. Unlike most generation projects, energy efficiency programs require thousands of individual contacts that, if successful, cumulatively reduce the need for additional resources. However, the level of detail and degree of understanding of energy efficiency resources need to be comparable to the level of engineering and technical detail provided for conventional generating alternatives.

Resource portfolio analysis

Most integrated resource plans today describe their output in terms of a preferred "resource portfolio". Since the future is not knowable, a utility system must be prepared to economically meet a wide range of possible futures, and portfolio analysis is the only way to concretely compare alternative strategies involving different resources.

Not all resource portfolios have the same degree of flexibility in response to changing conditions. A flexible portfolio allows the utility to maintain a close balance between supply and demand, thus minimizing the risk of finding itself unable to meet demand, on the one hand, or the financial risk of developing more resources than necessary, on the other.

In order for portfolio planning to be an effective tool, demand-side programs must be treated as a separate resource that can be added to the system based on cost and energy needs. Many utilities are now required to explicitly reconsider the use of intensified demand management programs before deciding in favor of any new construction, making demand- and supply-side resources compete on an equal basis. Since energy efficiency programs almost always have shorter lead-times and are available in quantities that more precisely match the expected shortfall, they have a strong competitive advantage over new plants.

Financial analysis

Because the choice of resources can have such a great effect on a utility's rates and its financial health, integrated resource plans must pay careful attention to financial issues. The analysis of resources must include study of the financial requirements for each type of resource and the financial risks of each resource strategy. The rate effects of each strategy must be analyzed with the understanding that escalating rates create not only an economic problem for customers but a political and regulatory problem for the utility.

Only by comparing the financial impacts of different resource strategies across different possible futures, is it possible to judge whether or not a given portfolio is financially viable.

Assessment and incorporation of externalities

In an integrated resource planning context, "lowest cost" refers not only to costs borne by the utility, but also to costs borne by other individuals or by society as a whole (environmental and social impacts). Since these costs are "external" to the utility's balance sheet, they are called "external costs" or "externalities". Finding a way to account for these external costs is perhaps the greatest challenge to the still-evolving field of integrated resource planning.

The various approaches to dealing with externalities can be broadly classified into those that monetize all impacts (express them in monetary terms) and those that do not. To the extent that it can be done effectively, monetization is a very desirable approach. Indeed, many specialists believe that unless external costs are fully monetized, they will inevitably be ignored in the final decisions on resource acquisition.

However, it is widely recognized that the major externalities of hydroelectricity are very different from those of fossil-fuel based systems, and are much harder to quantify. Monetization depends on first *quantifying* each impact, and then determining the monetary *value* that should be assigned to each unit of impact. Only if each of these steps is both technically rigorous and seen to be valid by all stakeholders will the resulting dollar figure provide a legitimate basis on which resource decisions can be based. Both parts of this process are complex and subject to large uncertainties.

Another approach seeks to bring out possible trade-offs between different costs and benefits without determining explicit monetary values. This appears to be the type of analysis favoured by the *Guidelines*, which do *not* call for full monetization, but which do require that the externalities of each resource be described as precisely as possible, whether in monetary, quantitative or qualitative terms. While no methodology is specified, they leave no doubt that, in addition to the economic and reliability issues described above, these environmental and social considerations should be taken into account in selecting the resources to be acquired.

A number of conceptual and practical tools exist to help decision-makers approach trade-offs more rigorously. The purpose is to find trade-offs where accepting a limited deterioration in one attribute will permit a large improvement in another.

The Analysis Group for Regional Electricity Alternatives (AGREA) at the Massachusetts Institute of Technology has recently developed an interesting approach to decision analysis based on multiple attributes of diverse energy resources. This method, which makes it possible to compare the costs and impacts of resources as different as hydroelectricity, gas and coal generation and energy efficiency programs, could be of use in the optimisation of resource portfolios in a complex context like that of Quebec. This type of structured analysis could permit an improved understanding of the trade-offs implicit in each alternative resource portfolio, and hence of the impacts on the economy and the environment not only of the Great Whale project, but also of the alternative resources that could be called upon to take its place.

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order to create jobs and promote industrial development.[9] While such policies are not within the control of an electric utility, their impacts on long-term planning may be quite significant. In order for the analysis to remain rigorous, the expected loads, their effect on choice and scheduling of future resources and their financial impacts must be explicitly accounted for in an integrated resource plan.

3.2 Supply-Side Resource Assessment

IRP requires a complete assessment of all potential resources, both supply-side (generation) and demand-side (conservation and energy efficiency). While environmental and other constraints will be dealt with later, the first problem is to compare the costs of supply-side resources that vary greatly in their length of service, necessary load-time, capital costs, fuel costs and operating and maintenance costs.[10] Planners usually use "levelized real life-cycle costs" to describe resource costs. This same measure can also be used to compare demand-side to supply-side resources.

The term "levelized real life-cycle costs" describes the series of hypothetical "real" per-kilowatt-hour payments that would pay for the resource over its lifetime. That is, it describes the cost per unit of the energy that would be produced by the resource in a hypothetical world where there was no inflation (hence "real", as opposed to "nominal" — see below) and where both the project's costs and its energy output remained at the same even level ("levelized") throughout its useful lifetime ("life-cycle"). This measure makes it possible to compare projects that have very different lifetimes and different patterns of energy production and costs spread out over those lifetimes. Using this type of

[9] These issues are addressed in the *Guidelines* in ¶219-222.

[10] Addressed in the *Guidelines* in ¶225.

calculation, one can for example compare a hydroelectric plant, which may have high initial capital costs but low annual operations and maintenance costs, to a gas-turbine generator that may have low capital costs but substantial annual fuel costs, which may also increase at a rate faster than the rate of inflation.

Of course, to make these comparisons, a full assessment of the energy output and costs of each resource over time is required. In addition, important assumptions need to be made. To calculate levelized real life-cycle costs, the planner must decide how to value future costs. This is done through the choice of a discount rate, the percentage by which future costs or benefits are "discounted" each year to account for inflation, interest, risk and uncertainty.[11]

To determine the levelized real life-cycle costs of a project, estimates of the annual costs for the life of the plant are "discounted" to their present value today, using a real (inflation-free) discount rate. This total present value cost is then converted to a stream of identical annual costs. Average annual energy output is divided into the levelized cost to produce an estimate of the real levelized unit cost.

While levelized real unit costs are a very useful tool, their limitations must be well understood. These costs *cannot* be used to compare a proposed resource with existing resources. This is because they exclude the effects of inflation, not just over the construction period, but over the entire life of the project. This inflation is a major component of the interest that will be paid on the bonds that finance the project for many years to come. Since the cost of the existing system (expressed, for

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[11] For a discussion of the issues involved in choosing the appropriate discount rate, see section 3.5 (Financial Analysis), below.

instance, in the system-wide average unit cost) *includes* this long-term inflation, the two types of costs cannot be directly compared.

Thus, the term is misleading, as levelized real life-cycle cost estimates are not comparable to the costs actually experienced by the utility and provide no indication of the rate impacts that will be experienced if the resource is built.[12] Even though the levelized real cost of a new resource may be no greater than today's average system cost, the resource may lead to substantial rate increases when it is commissioned. To avoid this type of misunderstanding, some utilities now use levelized *nominal* costs to compare resources. It is important to grasp this distinction, as the levelized nominal (current dollar) cost of a capital-intensive resource like hydroelectricity is usually about double the levelized real cost.

The following chart (Figure 2a) may help to explain these concepts.[13] It is based on a hypothetical example, a hydro project which would produce 10 TWh per year of electrical energy, starting in the year 2001. The total construction cost, including all necessary transmission line improvements, is $8.3 billion ($ 2001). This figure includes all financing costs from the beginning of construction until the commissioning date in 2001.

Under standard utility accounting procedures, this total cost is converted to a series of equal payments (like a mortgage), which would be necessary to pay off the total investment over the life of the project. This payment comes to $837 million per year, or 8.37¢ per kilowatthour. This figure,

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[12] The term used for this concept in Quebec ("coût de revient", or cost price) is perhaps even more misleading, in that it suggests that this is the actual cost to the utility.

[13] For the sake of simplicity, operating and maintenance costs are omitted. Financial assumptions used are similar to those in Hydro-Québec's *Development Plan 1993*.

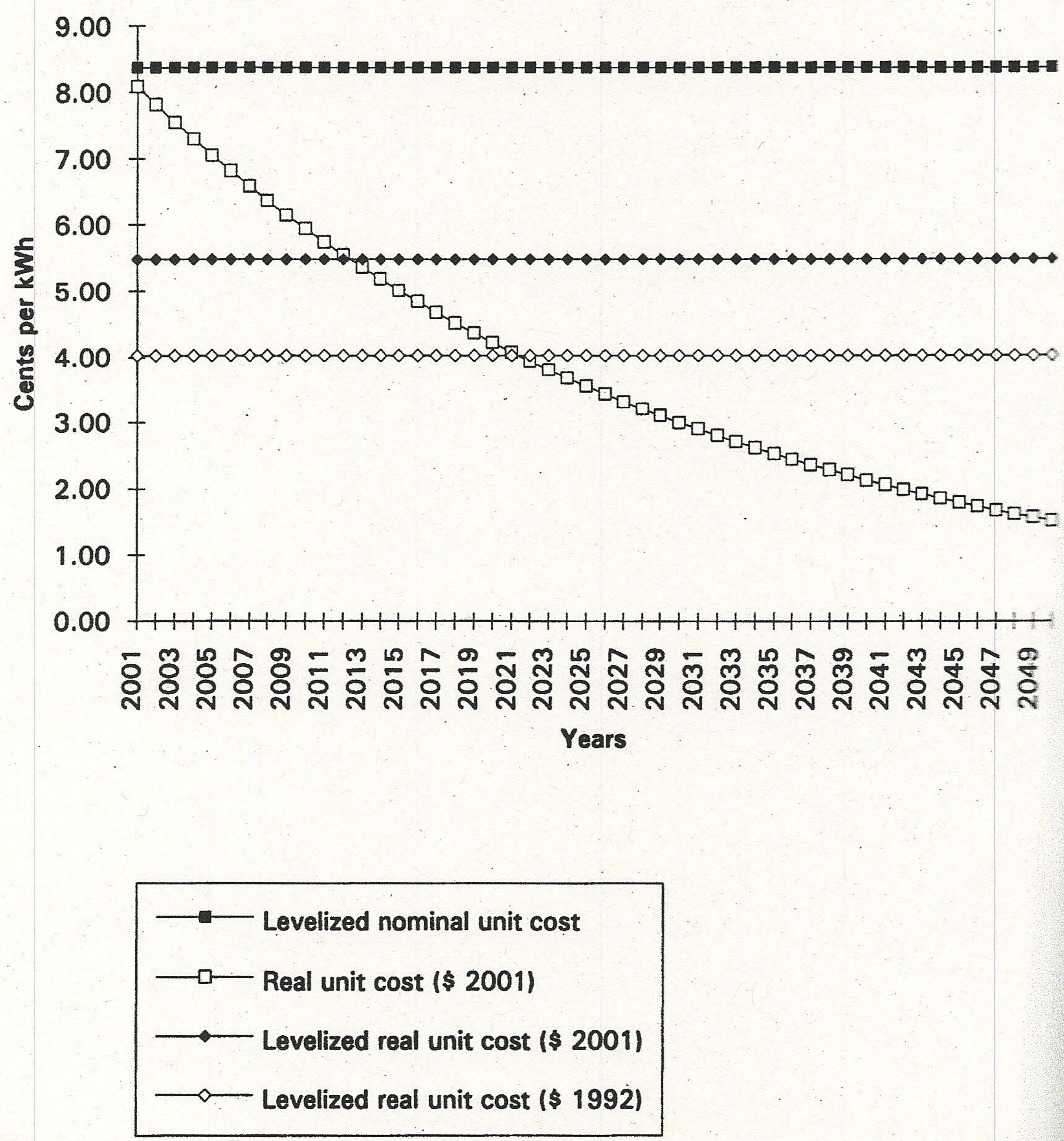

Figure 2a Levelized Nominal vs. Levelized Real Unit Costs

called the "levelized nominal unit cost", is the actual production cost, in current dollars, of the energy produced by the project. It is this cost that must be recovered in rates, in order to make annual payments (principal plus interest) on the debt incurred in building the project.

However, to be able to compare this project to others of different characteristics, it is often useful to convert these figures to "real" (inflation-adjusted) terms. Since inflation will slowly erode the value of the dollar over the 50-year life of the project, the real value of the 8.37¢/kWh payment will gradually decline — from 8.37¢/kWh in 2001 to 1.51¢/kWh (in 2001 dollars) in 2050. The inflation-adjusted value of this payment is shown in Figure 2a as "real unit cost".

If this stream of declining real payments is then replaced with a constant stream of real payments with equivalent present value, it yields a levelized real unit cost of 5.48¢/kWh, in 2001 dollars. Converting this figure back to 1992 dollars (by subtracting the rate of inflation each year) yields a levelized real cost of 4.02¢/kWh (1992 $), less than half of the levelized nominal cost given earlier.

All four of the curves in Figure 2a in effect represent equivalent economic value, equal to the $8.3 billion it will have cost to build the project when it is commissioned in 2001. A fifth way to express this amount is as a stream of annual payments indexed to inflation (fig. 2b). These payments would rise from 5.48¢/kWh in 2001 to almost 30¢/kWh in 2050. While this representation may be the best way to compare this project to a resource with costs which are also indexed to inflation (i.e. a contract with an independent power producer), it is an economic construct that does not reflect the way hydroelectric projects are actually financed.

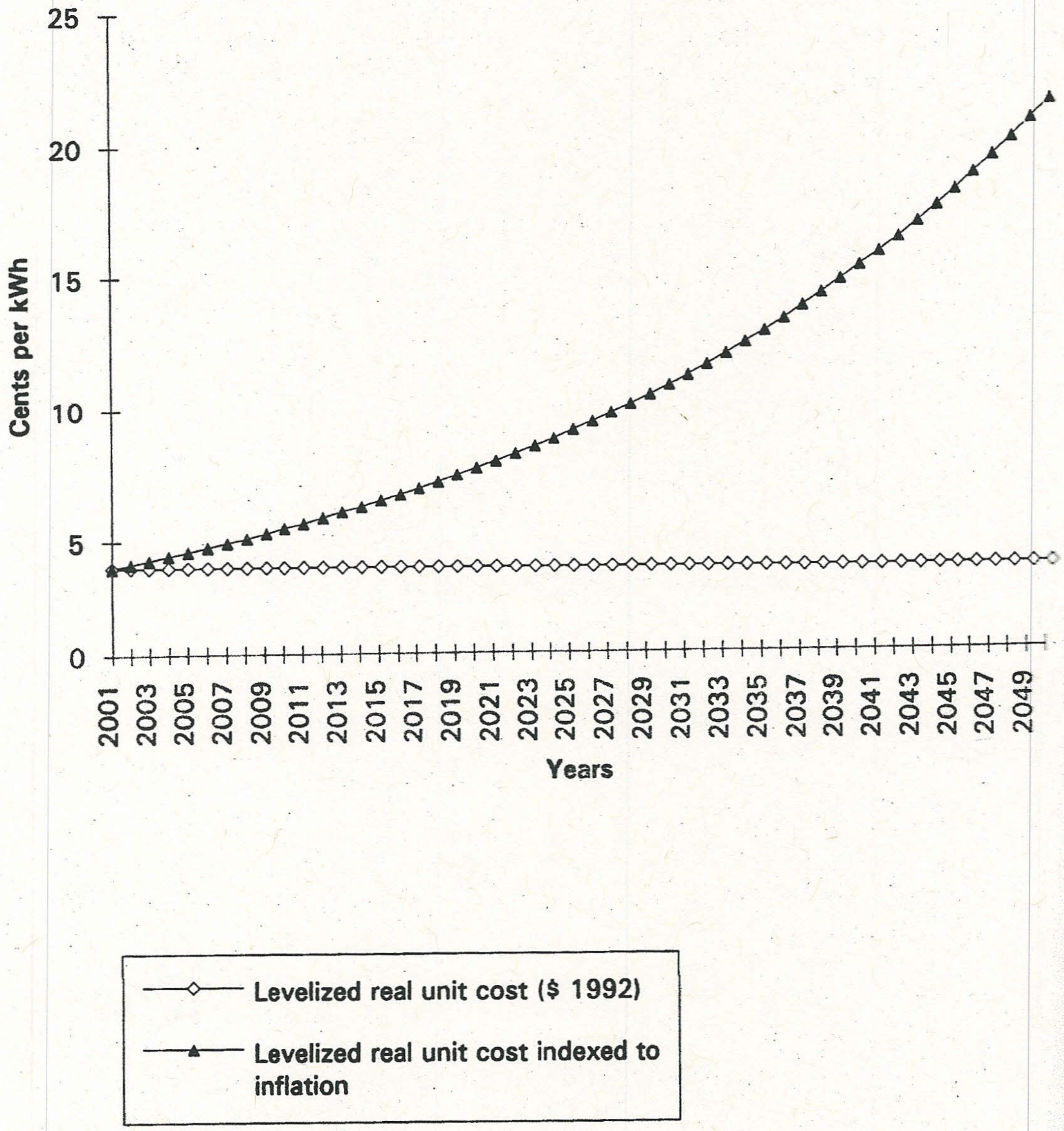

Figure 2b Real Unit Cost Indexed to Inflation

Thus, the rate impact of this hypothetical project when it comes on line in 2001 would be that of the levelized *nominal* unit cost, or 8.37¢/kWh. To the extent that this figure is greater than the average cost of the existing system before the new project is commissioned, rate increases would be required in order to recover these costs. It should be noted that, in situations like that in Québec today, where average system costs (of all existing installations) are lower than the nominal costs of new supply, *any* new investment in new generating capacity will tend to increase rates. This rate impact will be proportional to the levelized nominal cost of the new resource, which is about twice as great as the levelized *real* cost.

Thus, while real levelized unit costs give no indication of the rate impacts of different resources, they *do* make it possible to compare their costs, especially when they involve very different patterns of expenditure and energy production over time. For this reason, they can also be used to compare supply- and demand-side resources — a key goal of IRP.

Power Systems Analysis - Another difficulty in comparing different resources is in their varying contributions to meeting different aspects of the demand. In any electric system, demand varies from one time of day and of year to another. Inevitably, in order to be able to meet demand when it is at its peak, the utility must have generating capacity which is idle much of the time. Thus, peak resources, though cheaper per kilowatt, are usually considerably more expensive than base resources, on a per-kilowatthour basis.

IRPs must identify a combination of resources that, together with the existing system, can provide a mixture of resources with sufficient operating flexibility to meet the utility's loads at every point in time, and at least cost. To accomplish this, IRPs usually include a combination of base, intermediate and peaking resources. The base load resources are used to provide a steady energy output, and thus are designed to operate