EXPLORING VANCOUVER ISLAND'S ENERGY FUTURE

A Workshop with BC Hydro & Rocky Mountain Institute

July 14, 2003

Final Report

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Introduction and Summary

BC Hydro faces complex technical and economic challenges in formulating a least cost and resilient resource plan for Vancouver Island (VI). In the short term, due to the retirement of the HVDC transmission line from the Mainland, Vancouver Island will need at least 200 MW of new supply capacity by 2006 to meet reliability criteria. Although BC Hydro has a proposal for a new combined-cycle plant and gas transmission pipeline, regulatory hurdles could delay or halt construction. Therefore, a comprehensive contingency plan is required. Long term, regardless of whether the new gas facility is completed, BC Hydro needs to determine how to best utilize the total energy infrastructure (gas, power, renewable sources, end use demand) to meet its customers' energy service needs.

On Monday, July 14, 2003, Rocky Mountain Institute and BC Hydro held a workshop with BC Hydro staff and several external experts to explore the long-term energy needs of Vancouver Island. The workshop was designed to provide the opportunity for participants to brainstorm about Vancouver Island's electricity future, identify long-term (up to 20 years) potential options, and consider intermediate steps to realize such potential.

RMI's perspective is that solutions to these vexing problems require a broad, integrated perspective. Remarks by Amory Lovins and Kyle Datta reflect this view, "BC Hydro currently has an imminent 200 MW of capacity supply problem. If VIGP/GSX is delayed, the alternatives we have discussed as longer-term solutions become important contingency options, because they buy time. The question, then, is *how can VI get 200MW from a constellation of distributed resources* and maximize the value of the present gas and power infrastructure?

"*Price signals are key*. BC Hydro can effect change in customer behavior fast by ensuring that price signals are set up to produce the intended effect. Concerns over the intermittency of alternative, renewable options can be addressed by implementing a combination of technologies that will provide firmness: efficiency, renewable generation, cogeneration. *Pilot projects are needed now* to find out such things as how do customers respond to price. As a result of the workshop, BC Hydro has a range of options to consider."

While the focus of the workshop was on meeting the energy service needs of Vancouver Island, given the impending de-rating and retirement of the HVDC transmission from the Mainland, it is important to consider the broader context of British Columbia and the regional energy system as a whole. For example, new thermal generation on Vancouver Island may require additional gas transmission capacity, while any transmission-based solutions must include the generation options on the Mainland. Given the supply constraints on Vancouver Island, however, it is timely and relevant to consider supply and demand-side solutions tailored to the specific local needs.

The RMI/BC Hydro workshop on Vancouver Island's long term energy future served as an *initial brainstorming session* to pool the collective expertise and insights across BC Hydro departments, together with external representatives from government, academia and industry, facilitated by RMI to come up with twelve "breakout" ideas for further analysis. There are no "magic bullets" in these twelve ideas, nor are they a menu that can be combined arbitrarily. Rather, they are new options that BC Hydro can integrate into a robust portfolio. In this report, we suggest additional ideas and priorities that can complement the twelve proposed ideas from the workshop to better satisfy BC Hydro's planning goals.

The twelve proposed ideas cluster into four categories:

Marginal Costs and Price Signals:
- Peak load reduction through time-of-use rates, possibly island-specific
- E+ rate phase out
- Modify distribution extension policy, possibly including "feebates"

Demand-Side Management:
- Power Smart for peak reduction
- Smart water heaters
- Industrial curtailment

Generation and Distributed Resources:
- Energy storage on VI
- Cogeneration using natural gas or biomass
- Tidal, wave or wind power on VI

Transmission and Distribution Grid Solutions:
- Real-time metering to reduce line losses
- Convert 230kV Dunsmuir-Sahtlam line to 500 kV
- Modify transmission extension policy

In our view, several important themes underlie these twelve ideas:

- BC Hydro needs to know the *full marginal costs of service on an area- and time-specific basis,* including generation, transmission, and distribution, and costs should be risk adjusted to recognize the inherent pricing risks of increased gas reliance. This information will support the design of new pricing structures and provide a clear set of economic criteria for prioritizing investments in different types of DSM and supply resources, including distributed resources (DR) in the course of the IRP process.

- It is imperative to *get the price signals right*, within existing regulatory constraints, to guide customer behavior and investment decisions. Some pricing strategies should be designed specifically to limit peak demand and to shift electric hot water and space heating loads to gas or biomass.

- A *renewed regulatory compact* is needed in British Columbia to enable BC Hydro to reform its pricing structure and to provide financial incentives to implement all cost-effective demand-side management (DSM), energy efficiency and load management. This includes addressing the policy issues regarding province-wide equity when defining rate options.

- *Power Smart is one of BC Hydro's most important resources*. The present, expanded Power Smart can be augmented to reach more ambitious goals, to focus more on peak demand savings, and to target electric hot water and space heating, especially on Vancouver Island. The appropriate level of program expansion should be dictated by economic cost-effectiveness, using the full locational marginal costs.

- BC Hydro has a *range of generation options to purchase from the private sector*, which can provide long-term flexibility or provide alternatives in case the VIGP/GSX project is not completed. Options include other on-island generation, Mainland generation (and the needed transmission capacity), and *distributed resources*, such as cogeneration, energy storage and some intermittent renewable sources. Note that intermittent renewables will need to be combined into firm portfolios with other resources in order for some of their capacity to be considered dependable.

- The *full distributed benefits of a portfolio of measures* should be understood in terms of marginal costs, risk management, operational benefits, and reliability improvement. The challenge goes beyond electricity, as BC Hydro will need to determine the *highest value and best use of gas delivered* to Vancouver Island in terms of services provided.

- No single measure is a magic bullet, but BC Hydro can build a *combination of DSM and supply technologies, programs, and prices* into a successful portfolio. A portfolio of firm capacity can be assembled from resources whose production (or savings) profiles balance each other, even if each individual resource is not firm. This approach allows certain intermittent renewable sources to be harnessed for their capacity, energy, and emissions reduction value.

- Transmission and distribution access and costs are key to the development of future DSM and supply resources in BC, and especially on VI. Reliance on new generation sources on the Mainland would require additional transmission to VI as well as reduced transmission constraints on the Mainland. Meanwhile, *transmission extension policy modification for intra-Vancouver Island transmission* and a collaborative approach to financing could facilitate the realization of much of the *renewable generation* potential on VI.

We address these themes further below, as part of the discussion of the four categories of proposed ideas and resources. The categories are Marginal Costs and Price Signals, Demand-Side Management, Generation and Distributed Resources, and Transmission and Distribution Grid Solutions.

For each category, we provide a brief introduction, followed by a discussion of key strategies and conceptual themes. Then, we present the proposed ideas for that category in further detail. In some cases, we draw attention to related ideas that were not addressed in detail by group.

List of Workshop Participants

Speakers:	Ron Monk
Larry Bell, BC Hydro	Jai Mumick
Bev Van Ruyven, BC Hydro	Dennis Nelson
Amory Lovins, RMI	Peter Northcott
	John Oliver
RMI Facilitators:	Ted Olynyk
Kyle Datta	William Peterson
Michael Kinsley	Bruce Ripley
Joel Swisher	Catherine Roome
Kitty Wang	Bruce Sampson
	Glen Smyrl
BC Hydro Participants:	Rohan Soulsby
Jeff Barker	Steve Watson
Al Boldt	Ralph Zucker
Murray Bond	
Lester Dyck	**External Participants:**
Craig Folkestad	Hadi Dowlatabadi, University of BC
Richard Fulton	Alexis Fundas, Ministry of Energy
Devinder Ghangass	Dan Green, Ministry of Energy
Don Gillespie	John Hall, Cossette Communications
Mary Hemmingsen	Michael Margolick, Global Change Strateiges
Derek Henriques	Glenn McDonnel, Sigma/Synex
Lexa Hobenshield	Rose Murphy, Simon Fraser University
Steve Hobson	John Nyboer, Simon Fraser University
Nadja Holowaty	Andrew Pape-Salmon, Ministry of Energy
Altaf Hussain	Kirk Washington, Yaletown Ventures
Mike Krafczyk	Paul Willis, Willis Energy
Trudy Kwong	Tom Wilson, Keen Engineering
Richard Marchant	
Ken McDonald	**BC Hydro Recorders:**
Rick McDougall	Amandeep Basi
Ryanne Metcalf	Matt Good
Brian Moghadam	Amy Jenkins Swan
	Ryan Robertson

Marginal Costs and Price Signals

In the course of discussing potential solutions to BC Hydro's capacity imbalance on Vancouver Island, workshop participants observed that there seem to be discontinuities between the costs of service on VI and the tariffs that some or all customers pay. This discontinuity was most evident regarding the apparent incentive to install electric hot water and space heating on VI, despite the cost and potential reliability problems resulting from this source of new on-peak demand. Similarly, there is now little incentive to develop distributed cogeneration because the relative retail prices of natural gas and electricity (i.e., the retail "spark spread") are so unfavorable.

Therefore, before we address the many technology solutions that were proposed at the workshop, we first consider the problems and solutions related to BC Hydro's marginal costs and the tariffs that it charges to its customers. These potential solutions involve improving the alignment between BC Hydro's cost structure and the use of cost information to determine prices and conduct resource planning. Although any potential change in the pricing structure will take time and involve significant policy debate, the internal work to align costs and rates could begin soon. To prepare for future pricing reform, while supporting planning efforts in the shorter term, we suggest a three-part strategy:

1. Develop an improved understanding of the *full marginal cost of supplying power* at different times of the day and year, including generation, transmission, and distribution
2. Design customer tariffs to *align price signals with the actual costs* of service in space and time, within existing regulatory constraints, to guide customer behavior
3. Use the improved cost information in *evaluating and prioritizing potential supply and demand-side resources* as part of BC Hydro's integrated resource planning (IRP) process

At the workshop, the group reported in detail on proposed ideas mostly related to customer tariffs (strategy 2). These ideas are covered in detail following a discussion of costs and pricing. The proposed ideas are the following:

Peak load reduction through TOU rates, possibly island-specific
E+ rate phase out
Modify distribution extension policy, possibly including "feebates"

Problems with Energy Pricing in BC and VI

The basic problems with energy pricing in BC, as observed with regard to VI, are the following:

- Customer prices are based on historical embedded costs of service, not forward-looking marginal costs, which leads to situation where BC Hydro sells power at a loss (negative margin) to certain customer and/or at certain times.
- System-wide, postage stamp pricing fails to capture the area-specific nature of the cost of supplying electricity service, due to local T&D cost variations. At the very least, it seems reasonable that VI tariffs should be different from those on the Mainland, although this would introduce a significant policy issue.

- Pricing that is constant or that only bluntly captures time-of-use variations fails to capture the time-specific costs of meeting peak demand on a seasonal basis, which can be better achieved using new products such as real-time pricing or critical peak pricing.
- Uniform pricing across a rate class fails to capture variations in customers' tolerance of ability to reduce or curtail loads during times of high costs or capacity constraints, while more individualized curtailable rates can save both customers and the utility money.
- Pricing structures that require customers to accept gas-price risk for direct gas use, but force the electric utility to absorb this risk for gas-fired generation, creates a bias against direct gas use and against distributed cogeneration.
- Extension policies that socialize the marginal cost of new electric heating installations, while assigning the marginal cost to each new renewable generation source, create the incentive for inefficient investments and discourage new distributed resources.
- Customer prices do not reflect social and environmental costs of electricity production that are external to BC Hydro's direct cost structure.

Many of these issues can be resolved through a combination of the three strategies suggested above. The following discussion elaborates somewhat on some of our recommendations on the use of marginal cost analysis and getting the price signals right.

Best Practices in IRP and Marginal Cost Analysis

The problems identified above with regard to the price signals received by BC Hydro customers, especially on Vancouver Island, suggest that improved price signals would more directly reflect BC Hydro's true marginal costs of service. In order to support the reform of the price signals and the regulatory compact in BC, a full understanding of the structure of BC Hydro's marginal costs is necessary. Therefore, it may be helpful to reinforce BC Hydro's analysis of its cost structure and to communicate the results to managers and planners throughout the company.[1]

In addition to supporting the design of new pricing structures, an updated marginal cost analysis will provide a clear set of economic criteria for prioritizing investments in different types of DSM and supply resources, including distributed resources (DR). This information will be useful in BC Hydro's IRP process, and it will help put DSM, DR and traditional supply options on more of a level playing field in economic terms.[2] While the competitive tender process will reveal the relative costs of different supply options, it is useful to understand the cost-related attributes of each resource type, in order to set transparent criteria for evaluating supply and demand-side resources that make different contributions to meeting energy and capacity needs.

A marginal cost analysis should achieve the following objectives:

- Understand *when costs are high*, by time of day and year, by isolating the types of peak loads and supply variations or constraints that drive time variations in costs
- Understand *where costs are high*, by determining the financial impacts of incremental increases or reductions in loads at different locations in the grid (especially on VI)

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[1] Possible shepherd for further discussion: Richard Marchant

[2] See J. Swisher, G. Jannuzzi and R. Redlinger, 1998. *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Roskilde, Denmark.

- Provide a formal basis for comparing DSM and DR options at different locations, rather than relying on the rather distorted price incentives that customers see.
- Enable DSM and DR to be *considered as planning options early enough in the IRP* process to allow them to compete with traditional supply options.
- Identify the financial interests of all parties directly involved in the development of DSM, DR and traditional supply options, to enable effective design of incentive mechanisms.
- Account explicitly for intangible or external costs in analyzing resource costs, *even if these costs are not internalized in the planning process.*

To achieve these goals, today's best practices in utility marginal cost analysis and IRP process design are recommended. Some of the methods are rather data-intensive and may be difficult to implement fully with available information. Existing regulatory constraints will also limit the application of some of the methods. However, it should be possible to use some or all aspects of the recommended practices, as indeed BC Hydro already does, and the results should provide insights regarding the potential need for additional information and/or regulatory reform. The best practices in marginal cost analysis are outlined briefly below.[3]

- *Starting point*: The default supply plan, based on minimizing revenue requirements, provides a familiar costing framework and a reference point to compare other options.
- *Review process*: Screen for viable alternatives, including DSM and DR, with the initial plan as a benchmark, and iterate to find better solutions.
- *Project costing*: Use forward-looking engineering-based capital and O&M costs for each identified option. Historical costs can be a guide for projects costs but are not part of the marginal cost methods.
- *Marginal capacity costs*: Use a present worth method, which yields the cost of a given planning option and the value of deferring investment due to an incremental increase or decrease in net load. Econometric methods are backward looking and inappropriate.
- *Locational variation of marginal capacity costs*: Analyze area-specific costs by planning area, based on the present value of each area's expansion plan and load growth. Variations result from differences in resource costs, load profiles, and mostly from differences in capacity costs of local transmission and distribution expansion.
- *Time allocation of marginal capacity costs*: Allocate costs to hourly and monthly time periods according to their contribution to peak demand and supply variations or constraints.
- *Non-monetary costs*: Identify intangible and external costs explicitly, and include them in the results only if there is a mechanism to monetize these costs.

The result of using these methods will be a set of marginal cost streams on an area- and time-specific (ATS) basis. This information provides the basis from which to construct rate designs, such as those recommended in the workshop, that capture variations in location and time-of-use. Applying these methods should enable BC Hydro to deliver price signals that realistically reflect the situation on Vancouver Island, namely the isolated location of many VI loads (area-specific) and the contribution of peak loads to BC Hydro's capacity costs (time-specific). Another aspect

[3] See Knapp, K., et al., *Costing Methodology for Electric System Planning*, Energy Foundation, November 2000.

of the time-specific nature of marginal costs is that the marginal supply resource, and therefore its cost, varies seasonally and annually due to variations in hydroelectric production.

The marginal cost analysis will also provide an economic ranking of proposed DSM, DR and traditional supply options. This is useful in order to, for example, construct the utility resource supply curve for the IRP process and prioritize investments in new resources.

Getting the Price Signals Right: Toward a New Regulatory Compact

At the workshop, there was broad consensus that distortions in the energy pricing structure in BC encourage customers to use energy inefficiently and make it difficult for BC Hydro to implement efficient technical solutions. Stepped rates for industrial customers are already planned and represent a step in the right direction. The reaction of customers and the degree of political openness to this new rate option should provide an indication of the barriers and incentives for more comprehensive pricing reform in the future.

Workshop participants also recognized that Hydro can not, by itself, make radical changes to the pricing structure. Rather, Hydro will need to work with the BCUC and other government and stakeholder organizations to reform the regulatory compact in BC. This reform would enable the development of more efficient pricing structures in BC generally and on Vancouver Island in particular.

Some of the basic requirements of an effective regulatory compact regarding energy costs and pricing are the following:

- Keep the recovery of fixed costs usage-based from the customer viewpoint, rather than as fixed charges, to capture this component of the cost of service in customer price signals.
- Decouple the recovery of fixed costs for the utility from total usage or sales, to remove the incentive to encourage customers use more energy and avoid "lost revenues."
- Recover the costs of demand-side management investments from the full rate class, to remove the disincentive to help customers use energy efficiently.
- Make utility shareholder return performance-based, to reward efficient operation.
- Use revenue limits, not price limits, to define utility performance incentives, to allow performance-based incentives to reward energy efficiency rather than increased sales.

We recommend a new regulatory compact that both addresses the lost revenue problem and sustains performance-based incentives for managers of demand-side management (DSM) programs. We do not attempt here to design all elements of a regulatory compact for BC Hydro; our resources do not allow it, and such an exercise would be presumptuous in any event prior to consultation with other stakeholders. But experience elsewhere prompts some specific observations about key issues to address in the design process.

BC Hydro should propose to retain the current formula for incorporating fixed costs in usage-based charges, but the company should also propose modest annual rate adjustments that automatically correct for unexpected fluctuations in electricity use. If traffic over the wires exceeds or falls short of estimates made at the time rates are set, and the company either under-or over-recovers the fixed costs approved by the regulator, rates for the next year should be adjusted modestly to compensate for the under- or over-recovered revenue requirement.

The recovery of the company's fixed costs is then independent of the total volume of electricity passing over the wires, although the ratio of energy-charge revenues to demand-charge revenues is not affected. The investor-owned distribution companies in California have received approval for this regulatory treatment of their fixed distribution revenues (Sempra/SDG&E, Southern California Edison, and Pacific Gas & Electric). Undoubtedly they are motivated in part by recent evidence that electricity and gas throughput is volatile in both directions, but all have also cited the importance of aligning societal and shareholder interests in improved energy efficiency.

With a combination of usage-based charges and regular true-ups of electricity rates, distribution companies can help ensure that energy efficiency successes do not undermine their financial health. Aggressive energy efficiency improvement and load management can stabilize or reduce electricity use through encouragement from the local distribution company.

Electricity rates will then increase slightly to cover costs and restore the un-recovered fixed costs, but the *customers' electricity bill will drop* as cost-effective efficiency eliminates the need to purchase kilowatt-hours that would cost more. The utility will distribute less energy commodity with no corresponding fixed-cost-recovery penalty, while customers will benefit from avoiding the economic and environmental costs of unnecessary electricity generation. And distribution companies need not temper enthusiasm for tougher building and appliance efficiency standards with anxiety about cutbacks in the budgets that sustain reliable grids.

The most controversial feature of decoupling mechanisms is the potential need for small annual changes in rates, which are needed to prevent unexpected fluctuations in sales from affecting recovery of the utility's fixed costs. This can be made more palatable to all parties through upfront assurances about customers' maximum exposure to annual rate changes. The mechanism can be applied either to the system as a whole or to major customer classes individually.

The chart below compares the performance of the recently adopted decoupling mechanism that operated for PacifiCorp's Oregon system from 1998 to 2001.

RATE IMPACTS OF PACIFICORP'S DECOUPLING MECHANISM, 1998 - 2001

NOTE: In May of 1998, the Oregon PUC adopted a true-up mechanism similar in some ways to this proposal, as part of an Alternative Form of Regulation (AFOR) for PacifiCorp. Three annual true-ups occurred under the mechanism before it expired in July 2001 (no decision has yet been reached on its successor). Rate impacts of the true-ups were extremely modest for all classes, and went in both directions:

	1999	**2000**	**2001**
Residential:	-0.39%	+1.90%	+1.85%
Small General Service:	+0.60%	+0.22%	+0.06%
General Service:	-0.83%	-0.31%	+0.09%
Large General Service:	+0.61%	+0.33%	+0.30%
Irrigation:	+0.45%	+0.25%	-0.20%

Utilities traditionally have been able to increase their fixed cost recovery over time in proportion to increases in throughput, which provided additional capital to meet the needs of an expanding grid (although obviously there is no guaranteed and precise relationship between throughput trends and incremental capital needs). Since decoupling removes this opportunity, an alternative formula is needed to allow the revenue requirement to grow (or contract) between rate cases to track the changing needs of the system.

One option is to set the fixed-cost revenue requirement for each rate class on a per-customer basis, so that a growing customer base provides equivalent additions to BC Hydro's fixed-cost recovery (even as BC Hydro would share the pain of a contracting economy). An alternative is for the Utilities Commission to set the rate of increase in a rate class's fixed-cost revenue requirement between rate cases at the average rate of increase recorded for the class over the past decade, based on increases in throughput or customer population over that time. The Commission also could use an independently maintained index that tracks either general inflation (the Oregon Commission's choice) or local economic activity, with annual changes in the fixed-cost revenue requirement tied directly to changes in the index.[4]

An additional design issue involves allocation of weather-related sales risk, which will assume increasing significance as air conditioning use and loads grow. If the preference is to leave the risk with the utility, then throughput must be weather-adjusted before the true-up is calculated, and the Commission will need to approve a weather-adjustment methodology for this purpose.

Decoupling mechanisms, however well designed, are a necessary but not sufficient part of a sound DSM regulatory compact. They eliminate a strong disincentive to cost-effective DSM programs, and they remove the temptation to make DSM expensive (to use up DSM budgets without reducing sales). However, decoupling does not by itself reward success. We recommend that BC Hydro seek to combine performance-based incentives with its lost revenue recovery mechanism, under a renewed regulatory compact based on revenue, not price, regulation.

Once the utility's cost recovery is decoupled from sales, and DSM cost recovery is assured, the remaining issue regarding DSM incentives is to reward successful and efficient DSM programs. The problem with conventional performance-based ratemaking (PBR) is that its incentives are based on limiting revenue requirements per unit of sales, i.e., the average energy price. This approach is contrary to the decoupling strategy, as it rewards increased throughput.

Therefore, it is essential that the renewed regulatory compact provide incentives to limits the revenue requirement per customer, rather than per unit of sales. This is commonly referred to as *revenue-cap, rather then price-cap regulation.* Designing the details of a revenue-cap PBR regime is beyond the scope of this assignment, but we can outline some of the objectives.

The main objective is to minimize customers' bill through an optimized combination of DSM and supply investments. A revenue-limited PBR will therefore provide the utility with a higher return on any investments that meet customer needs at lower net cost. DSM programs that save

[4]See Public Utility Commission of Oregon, Order No. 98-191 (May 5, 1998) (adopting "alternative form of regulation" based on proposal by PacifiCorp, the Oregon Department of Energy, the Citizens Utility Board, the Natural Resources Defense Council, and the Northwest Energy Coalition).

energy at less cost than the marginal supply costs will therefore earn a return for utility shareholders, and this return should be higher than that on more expensive options.

Thus, this approach encourages DSM programs where they are cost-effective, which will likely increase the rate of DSM investment. It also rewards the utility for making DSM programs more cost-effective, by achieving greater savings per dollar invested, and this will eliminate the present incentive to make DSM more expensive.

Peak Demand Reduction Through Time-of-Use Rates for Residential & Commercial Customers

NEXT STEPS: Establish a TOU rate structure for residential and commercial customers on VI
Develop the technical design and requirements to implement the rate
Make a business case to justify the investment

BC Hydro currently has time-differentiated rates only for industrial customers and then only at a crude (low time-resolution) level. Establishing aggressive time-of-use (TOU) rates for residential and commercial customers and coupling the rates with the targeted load would encourage customers to curtail energy use during peak periods and possibly shift loads to non-peak periods. This will further one of the new goals being considered for Power Smart, which is to focus on capacity reduction initiatives in addition to energy initiatives.

Applying TOU rates with targeted load management could possibly reduce peak consumption by an additional 70MW on top of the 125 MW reduction in the current CPR plan, bringing the total reduction to about 200 MW in 10 years, or possibly 20 MW/year. The benefits are larger in the winter months when rates would be higher. Together with planned Power Smart measures, this one measure could eliminate almost all of the projected annual peak growth on VI, assuming that further study confirms the estimated 70 MW potential. The new rate would be applied to all new and existing customers, and would be time-of-day and season dependent. The costs of implementing this program will need to be studied in further detail.

Barriers to implementing the program include a lack of local-area & time-specific avoided costs, possible opposition to changes in rate structures, the additional cost of installing smart meters, and the currently low rates charged for electric service. To accelerate the timeframe of this project, BC Hydro could implement a small TOU rate pilot program in the near term and learn from it. Ontario already has a high temperature water heater designed with a timer. In 1997 West Kootenay implemented this approach on a voluntary basis, and also offered an interruptible rate.

Additional questions:

- Is advanced metering required? It is not necessary for water heater control, but to give customer credit from time of use you need it.
- Are the metering costs justified, especially for small customers?
- Are there additional synergies involved in advanced metering, such as labor savings from automated meter reading, that would justify the costs of metering?
- Is it worth changing out meters? Although studies have found mis-wiring in meter change-out programs, there is also synergy with automatic metering, and the utility could put in meters that track water, gas and electricity at one time.

Another idea that was proposed but not developed further: Vancouver Island-specific rates. Based on a comprehensive area- and time-specific marginal cost analysis, BC Hydro could determine the cost premium for serving Vancouver Island. This premium would be the basis for establishing a separate rate from the postage-stamp rates used for the remainder of the province.

If combined with aggressive TOU, RTP or CPP rates, an island-specific rate could send the correct price signals to customers, i.e., prices that indicate the marginal cost of supply.

A change from the existing postage-stamp rates would have to be addressed at the policy level, as one argument for the traditional rate structure is that postage-stamp rates are equitable, regardless of the cost premium of serving one area compared to another.

Because this approach would likely increase average rates on VI, it would of course be unpopular. Therefore, the establishment of island-specific rates would have to be accompanied by an increase in DSM and other customer-service initiatives on VI. Targeting DSM to Vancouver Island would be indicated in any case by marginal cost analysis showing relatively high avoided costs and thus valuable savings on VI.

E+ Rate Phase Out

NEXT STEPS: Initial business case and explanation of the project.

Currently, BC Hydro has a special "E+" rate of around 3 cents/kWh that is charged to some customers who have a secondary heating source. Instituted many years ago, this rate is no longer appropriate in today's energy climate in B.C. It sends the wrong signal to customers because it encourages energy consumption rather than conservation. Eliminating the E+ rate, then, would remove this perverse price signal while, at the same time, making rates (hopefully) more transparent.

Savings from phasing out E+ rates on VI would probably be about 80 GWh/yr, with peak savings of approximately 40MW. Fuel consumption improvements will depend on the efficiency of new versus old equipment. Environmental impact will depend on the fuel source of the alternative heating resource. The exposure to gas-price risk will likely decrease for BC Hydro as a result of reduced energy consumption, but might increase for the customers as their direct exposure to the gas market increases.

A possible approach to executing the E+ rate phase out could entail the following:

1. BC Hydro sends a letter to existing E+ customers providing them information on what it is and announcing BC Hydro's intention to phase out the rate.
2. BC Hydro first encourages customers to voluntarily stop using the rate, then offers to help them implement efficiency upgrades and/or upgrades to secondary heating systems in order to compensate for the increase in their electricity bills. BC Hydro could show these customers that it is possible to keep the same energy bill despite the higher rates through the use of efficiency measures.
3. Start charging customers 18 cents per kWh during peak times to force curtailment, as allowed by the rate (but not done to date), or increase the rate incrementally over three years or so, until it matches rates charged to non-E+ customers.
4. Gradually phase out E+ rate.

BC Hydro will need to ensure that the E+ rate phase-out is accomplished fairly. The rate currently is not fair to non-E+ customers who must pay higher rates. An important question to consider is the political dimension of E+. BC Hydro will need to be careful that existing E+ customers are not low income and/or are representative of the population of BC Hydro service territory.

Modify Distribution Extension Policy

NEXT STEPS: Develop business case, including possibly "feebates"
Coordinate with Terasen and other stakeholders such as Home Builders Associations, etc.
Determine actual cost of new supply on VI

The current distribution extension policy does not motivate residential customers to choose gas space heat over electric heat. Due to the relatively short time gas has been available on Vancouver Island (since 1991), customers tend to expect their homes and water to be heated electrically. But as natural gas becomes the electric generation source at the margin, it is less efficient to use gas-fired electricity for resistance heating than using the gas on site to heat buildings directly where possible.[5] Also, once customers experience homes heated with gas, they tend to prefer it, regarding it as more controllable and comfortable.

Furthermore, increasing the number of electrically heated homes is counter to BC Hydro's current and future goals on VI. BC Hydro has an incentive structure for residents to adopt gas heating. Modifying the extension policy to discourage electric heating while making customers more aware of gas incentives would help alleviate short- and long-term capacity supply constraints facing the island.

Currently, customers who apply for a distribution extension from BC Hydro are subject to the System Extension Test (SET). The SET compares projected revenues against the cost of extending a line. Customers with positive net margins are not charged an extension fee but instead pay a connection fee. Customers with negative net margins are considered uneconomic and are charged an extension fee equal to the net margin in addition to a connection fee. Following payment, some qualifying customers are given refunds while uneconomic customers are provided financial assistance to cover the additional payments if such need is demonstrated.

If a SET were implemented to discourage the use of electric space heating and hot water, a preliminary calculation suggests that the VI peak demand growth would drop by about 8.4 MW per year. About 4000 new homes are constructed on VI each year. This is a combination of single-family and multi-family homes. It is assumed that 75% of these homes use electric heat and hot water.[6]

The up-front cost for BC Hydro would be the design and implementation of a new SET, along with the costs of regulatory approval. These costs would be relatively low, under $1 million. Operational costs would be low as well. This idea would be a modification of the existing SET and as such should not require significant incremental costs.

Slowing peak demand growth on the VI electric system should have a positive impact on the reliability of the electric system. Gas system reliability should not be negatively impacted with

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[5] On the other hand, if natural gas does not become the marginal generation source, and if BC Hydro achieves a long-term system vision of 100% renewable energy, then at least from an emissions perspective direct gas heating would appear less attractive. Under this scenario, the lowest-emission technology might be advanced heat pumps.

[6] It is also assumed that the capacity impact of electric heat is 2 kW and hot water is .8 kW. So the combined impact on VI peak is: 4000 homes x 75% x (2 kW + .8 kW) = 8,400 kW or 8.4 MW on VI Peak.

increased load growth, especially if current load growth is below that for which Terasen VI has planned. There is little to no risk to BC Hydro. However, consumers may be exposed to higher and more volatile natural gas prices because they will be purchasing the gas service directly, rather than paying BC Hydro a regulated electricity rate.

Additional questions:

- Might BC Hydro provide rebates for very efficient building envelopes (Terasen benefit)? Should customers with super efficient electric homes be allowed to keep the electric heat?

Another idea that was proposed but not developed further: "Feebates." Amory Lovins and others suggested a "feebate" approach, which might be explored as part of the business case development. Such a scheme could include a fee to inefficient homes, which would then be used to provide rebates to more efficient homes. A coordinated feebate with Terasen might make the most sense. For example, the fee could be high enough that the consumer switches to gas space and water heat (Terasen benefit) and installs very efficient lights and appliances (BC Hydro benefit). Although BC Hydro would lose revenues, due to the high marginal cost of serving such loads, it would probably result in improved margins, especially if electricity tariffs are modified to decouple earnings from sales.

Demand Side Management

BC Hydro's potential capacity imbalance on Vancouver Island results from continual load growth in the residential and commercial sectors in the southern part of the island. While the rather uniform, high load-factor industrial load is declining, this decrease is more than overcome by growth in the building sectors. As a result, demand on VI is not only increasing, but it is imposing sharper peak loads (lower load factor) on the BC Hydro system during cold winter weather. Total peak demand on VI is now somewhat more than 2000 MW and average demand is about 1200 MW, with total annual consumption of about 10,000 GWh.

Research and analysis by RMI and others, as well as the successful track record of Power Smart and other utility program, demonstrate that improving end-use energy efficiency can save energy at less cost than producing energy from new sources. Similarly, it is often cheaper to manage peak loads at the end use than to install additional production capacity to meet peak demand.

The strategy of demand-side management (DSM) combines the following four strategies for meeting customers' demand for energy services at least cost:

1. Reduce energy demand through *end-use efficiency, using improved technology* to serve new and existing loads.
2. Shift or reduce peak demand using *load management and demand response* technologies, including communication of the occurrence of peak loads to customers.
3. Fuel shifting from *electricity to natural gas or biomass*, for loads such as hot water and space heating, which can be met more efficiently by non-electric energy carriers.
4. Price signals that indicate the *full marginal cost of supplying power* at different times of the day and year, to influence the amount and timing of customer usage.

Strategy 4, improved price signals based on BC Hydro's marginal costs, is discussed in detail under Marginal Costs and Price Signals. Some of the pricing strategies are designed specifically to create or strengthen incentives to shift away from electric hot water and space heating. Thus, fuel shifting (strategy 3) is also addressed under Marginal Costs and Price Signals.

At the workshop, the group reported in detail on proposed ideas mostly related to peak load management (strategy 2), which is discussed in detail below:

Power Smart for peak reduction
Smart water heaters
Industrial curtailment

Energy Efficiency

Although improving energy efficiency is the core of any DSM strategy, including that of BC Hydro's award-winning Power Smart program, efficiency measures were not singled out for discussion at the workshop as much as peak load management strategies. This is because Power Smart has many successful on-going efficiency programs, which are now being expanded, and efficiency was therefore not treated as a new option at the workshop, which focused on new and longer-term options. Nevertheless, the importance of maintaining and extending BC Hydro's energy efficiency efforts on Vancouver Island should be emphasized.

Power Smart has recently produced a comprehensive Conservation Potential Review (CPR). The CPR identifies achievable energy savings on VI of 840–1270 GWh/year by 2012. Capacity savings resulting from efficiency programs would be 105–165 MW by 2012. These savings amount to approximately one-half to two-thirds of the projected demand growth during the same period. I.e., only one-third to one-half of VI's net load growth needs to be met by new supply-side resources, if the achievable efficiency potential identified in the CPR is captured.

Although these levels of savings would represent ambitious targets, the CPR may be somewhat conservative. Additional savings may be possible from actions not included in the Conservation Potential Review, such as programs to encourage customers to use gas space and water heat rather than electric. This strategy can reduce the need for electricity supply capacity to meet peak loads, as well as fuel demand and emissions at the margin.

Some of the key energy efficiency initiatives that were identified during the workshop for further development include the following:

- Efficiency measures for loads that specifically coincide with winter peak demand, e.g., Light Emitting Diode (LED) holiday lighting
- Minimum performance standards for buildings, focusing on overall system performance to encourage green, whole-system design and possibly building on the BC Building Code
- Minimum performance standards for appliances and other end-use equipment
- Overall market transformation strategy for buildings and end-use equipment
- Integration of efficiency with load management, fuel switching and rate design to "stretch" the Power Smart targets to achieve and expand the overall load reduction potential

Of course, there are barriers to further market penetration of energy-efficient technologies, including lack of consumer awareness, misaligned incentives, and varying or inadequate program funding. These barriers would need to be identified and overcome to reach or expand the achievable efficiency potential.

One national initiative that could help support the implementation of energy efficient technologies is the recently announced Climate Action Plan, is which relevant funding commitments include the following:

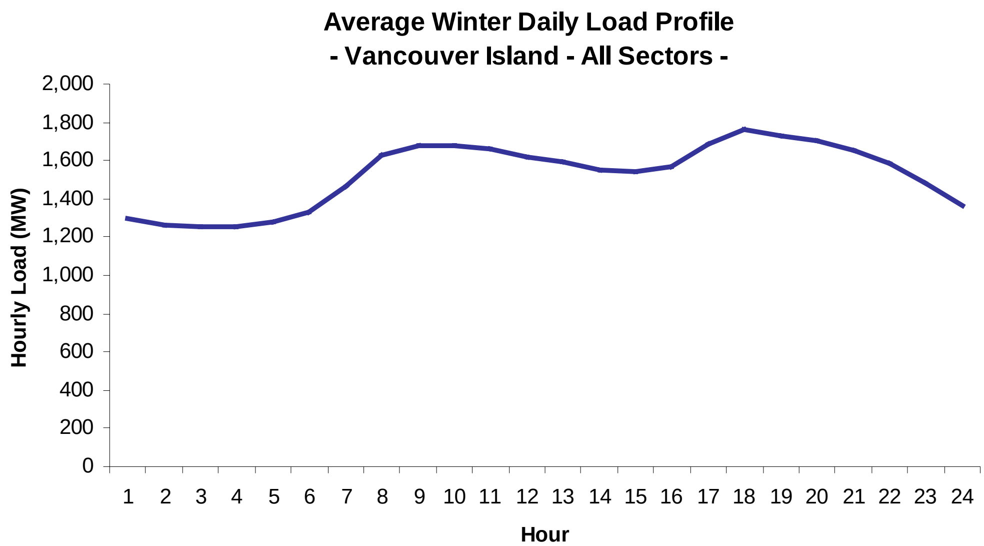
- $73.4 million in incentives to encourage energy-efficiency retrofits in existing houses
- $56.6 million in incentives to encourage efficiency retrofits in commercial buildings
- $47.2 million to encourage new commercial buildings to exceed National Energy Codes
- $25 million in incentives to encourage use of renewable energy in buildings

Peak Load Management

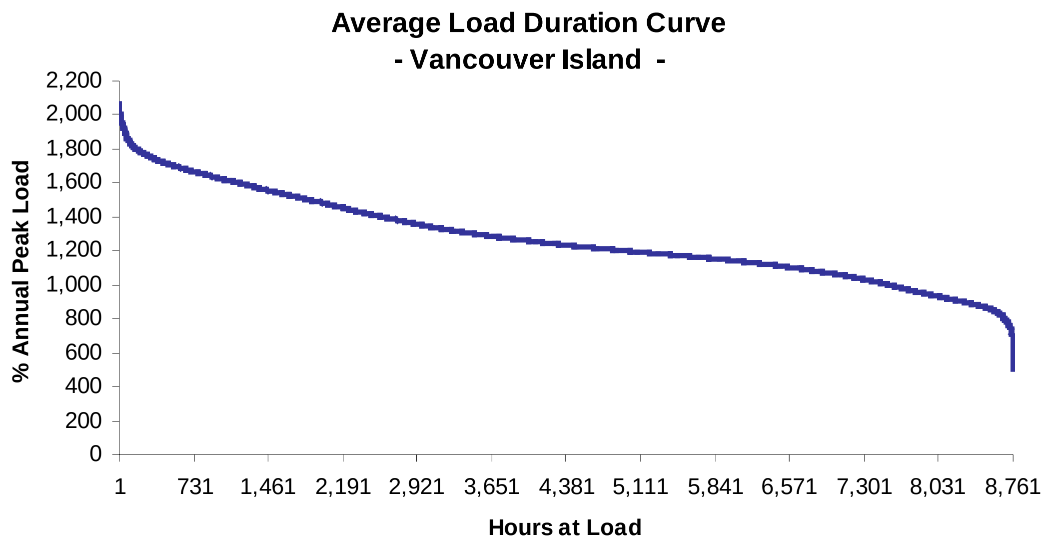
Most measures considered in the Conservation Potential Review address savings in energy (GWh), which is the primary planning parameter for a mostly hydro-based, energy-limited system. However, because of capacity constraints on VI, its system is limited by its capacity to meet peak demand, rather than strictly energy. In the future, the BC Hydro system as a whole will also become more capacity-limited. In a capacity-limited system such as on VI, savings in peak demand (MW) may be valuable and important to ensure reliable service. Thus, demand savings from peak load management, direct load control, and demand response programs would be a major addition to the demand-side resource potential identified for VI in the CPR.

The Load Shaping Challenge

BC Hydro faces a uniquely challenging problem: shaping peak daily loads on Vancouver Island. The pervasive penetration of residential baseboard electric heat and hot water cause a dual peak in the morning from 7:00-9:00 and in the evening from 17:00-20:00. The difference between the morning and evening peak is approximately 100 MW on an average winter day and about 150 MW on the peak day. The afternoon trough is approximately 200-250 MW below the evening peak on an average winter day and about 300 MW on the peak day.



Vancouver Island's load duration curve suggests that approximately 200 MW of peak load management could clip the system peak and improve load factor. The challenge is to install load management measures that can shift both the morning and evening peak cost effectively.



Peak load management should be viewed by BC Hydro as a complement, not a substitute for Power Smart's focus on reducing energy consumption. Efficiency will still be the most cost effective method for managing overall energy demand on Vancouver Island. Moreover, Power Smart efficiency programs can augment load management efforts on VI to the extent they reduce energy use in end-uses that coincide with the peak demand periods.

Benefits of Creating Demand Response

Demand response is a necessary prerequisite to fully functioning electricity systems and an important tool for maintaining reliability at reasonable cost. Demand response on Vancouver Island can provide the critical reserve needed to maintain reliability in case of a first contingency failure of a power supply resource. Control technologies now allow instantaneous control of end users loads as part of the utility's control system. Together with smart meters, demand response technologies impact can now be measured and verified in real time (15 minute intervals).

Demand response is also a critical tool for financial risk management in the more volatile, deregulated power markets. Customers must be sent timely price signals and have an automated capability to respond to prices for the power markets to be "tamed" and price volatility reduced. Once this capability has been created, demand response becomes an important risk management tool for load serving entities, in that it enables them to manage their spot purchases and fundamentally reduce the spot price by reducing their demand.

Residential load management can provide seven different types of value to load serving entities, as shown in the table below.

Value Drivers	Details
Lower Supply Costs – Reduction in Capacity and Reserve Margin Requirements	▸ Load management reduces the utility's system peak thus reducing capacity and reserve margin requirements
Lower Supply Cost: Energy	▸ The cost of supply will be reduced because: – Load management shifts load to lower cost energy time periods, lowering costs to serve directly
Risk Management	▸ Two types of risk management considered: – Energy hedging value: value of reducing exposure to peak costs, based on expected volatility. This allows more sophisticated supply portfolio management and trading interactions with the market – Power market can be "tamed" if 5% of total system load is shifted to demand response - dispatching GoodWatts during peak could both reduce the LSE's spot exposure and reduce the supply price to the remaining exposed load
Ancillary Services Value	▸ Load management can provide 10 - minute non-spinning reserve, and potentially spinning reserve as well
MDCC Value	▸ Utilities could avoid Marginal Distribution Capacity Costs by deploying "negawatts" intensively vs. distribution constraints
Meter Reading /Service Value	▸ Eliminate monthly manual meter reading by meter readers as well as special manual reads and rereads by using daily reads provided by the system. Total benefit includes reduction in all direct meter reading expense, supervisory expense, and materials.Additional value includes reduced service visits, uncollectibles and related expenditures
Option Value	▸ Because of potential for staged investment, Load management can be used as an option to manage the risk from future power market price spikes

Advances in Residential Load Management

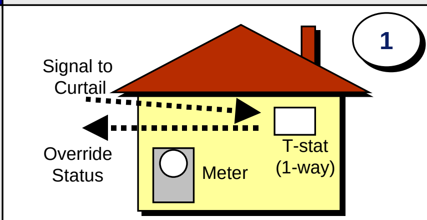
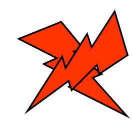
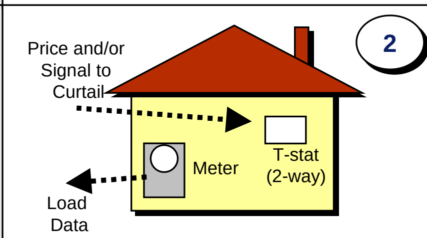
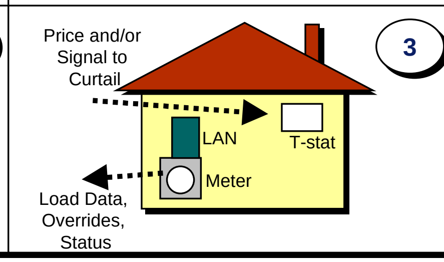
Residential load management has been used effectively to control air conditioning, heating, and hot water loads by several US and Canadian utilities. The prior generation of residential load control was primarily based on under-frequency relays to cut off power to the end use device.

This generation of technology suffered from several problems that limited its overall penetration:

1. There was no feedback loop to allow the customer to maintain the desired climate range in the home. Thus the customer was inconvenienced. The utility had no feedback on device status.
2. Real time measurement and verification systems were lacking, hence the utility would have to rely on statistical techniques to determine after the fact how much peak load was actually reduced.
3. Each device was controlled with a separate interruption system within a closed architecture, increasing the capital cost

The next generation of load management devices addresses these previous flaws. Typically, they are coupled with smart meters to allow real time measurement and verification and provide revenue quality data on customer responses in 15-minute intervals. This current generation of devices has two-way communication systems, which allow the utility to send signals, and measure the actual response, in real time, as well as maintain the climate settings within the customer's home to within the tolerable set points. The most advanced load management technologies communicate with multiple devices in the customers home, and use the same information and control protocols as the next generation of controllable appliances (e.g. dishwashers, refrigerators, etc.).

However, the benefits of load management depend on the system configuration. As shown in the figure below, the earlier generations of load management devices cannot capture all the potential values in the system.

What is Needed	SMART THERMOSTAT Allows utility to verify customer receipt of signal and monitor overrides	GATEWAY SYSTEM Allows communicatioon to, from, and between devices on local area network (LAN). Utility can verify signal reception and monitor overrides in real time.
ADVANCED METER • Load impacts and incentives must be estimated based on average customer • Not real time, end of day M&V of impact		
SMART METER • One-to-one correlation between measured load impacts and incentives • Incentive to conserve can be integrated into rate • 1-hour delayed response		

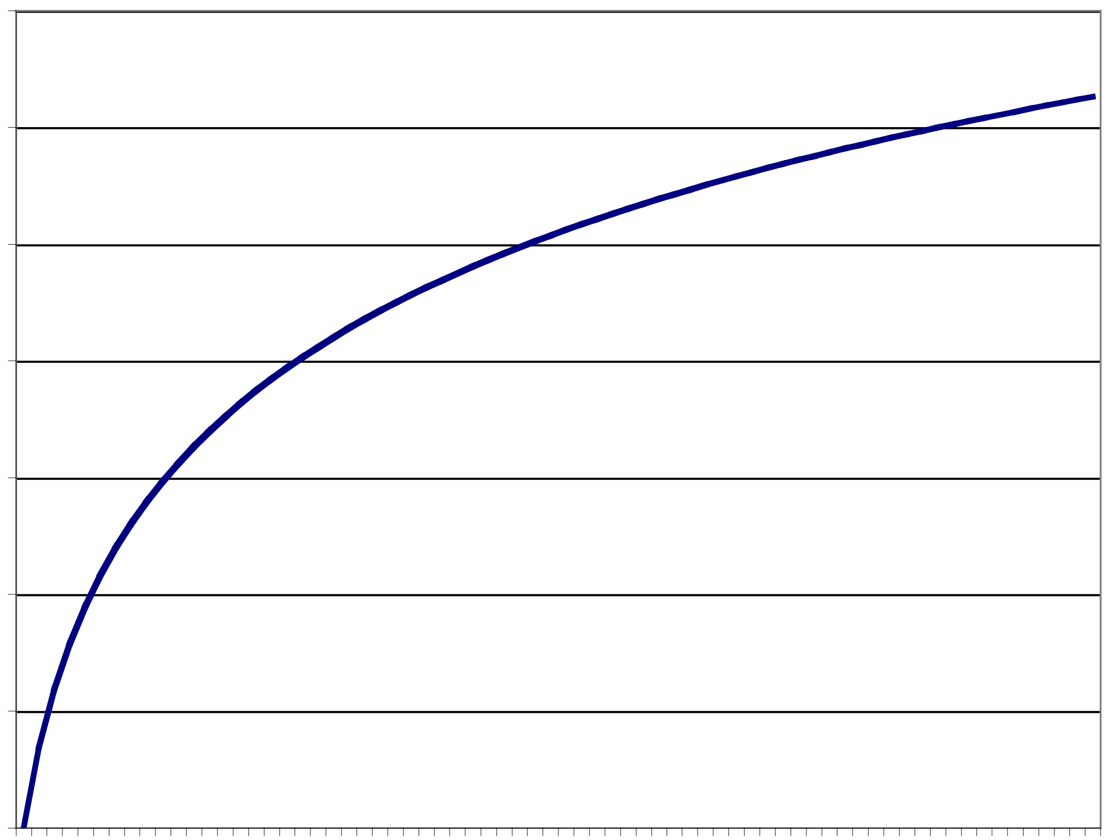
Lessons Learned in Industrial Load Management

The recent power crises in the United States have provided important intelligence about how industrial consumers respond to load management initiatives. First, industrial consumers have greater price elasticity and manufacturing flexibility than most utilities recognized. What has been lacking was the economic price signals to create financial incentives for customers to shift loads. In this regard, Georgia Power's experiment with critical peak pricing demonstrated that the load shifted by industrial customers depends on the price signal (as shown below).

Second, the pricing signals must be sharp, not blunt, instruments. Hourly or real-time pricing signals generate a significant price response, whereas blunt time-of-use or peak/off peak prices do not. Georgia Power obtained 5,000 MW of load reduction from 1,700 large commercial and industrial customers using real-time pricing. Duke Power obtained 1,000 MW of load reduction from 100 large industrial customers using hourly pricing.

Third, some industrial customers fundamentally change their manufacturing processes (or shift locations entirely) in response to long-run price signals. This was evident in the response to the oil shocks of the 1970s and 1980s. It is becoming evident in response to the repeated power crises of the last several years. Large customers want protection from reliability-related business interruptions. They are simultaneously conserving energy and investing in physical insurance, through either distributed generation and/or UPS systems. Vancouver Island's industrial customers have paid artificially low power prices (compared to marginal costs) for years. Thus, BC Hydro should expect some degree of structural change when the prices signals are rationalized.

Industrial Load Reduction in Response to Price Signals at Georgia Power



Source: Christensen Associates

Implications to BC Hydro

BC Hydro will need approximately 200 MW load management to shape its load, thereby averting reliability and cost problems. In order to get this magnitude of load management on Vancouver Island, BC Hydro will need to directly address the residential sector. Fortunately, the latest generation of load management technology makes such an endeavor viable. Given the urgency of the capacity situation, BC Hydro should be mobilizing to do an initial pilot of these technologies this winter, in order to have contingency capacity available in 2006.

Power Smart for Peak Reduction

NEXT STEPS: Firm up MW savings estimate
Identify specific opportunities and value them
Develop business case

Power Smart has historically focused its efforts on reducing annual energy consumption. This is typically the primary planning parameter for a mostly hydro-based, energy-limited system. However, because of the capacity constraints on VI, its system is limited by its capacity to meet peak demand, rather than strictly energy. In the future, the BC Hydro system as a whole will also become more capacity-limited. In a capacity-limited system such as on VI, savings in peak demand (MW) are especially valuable to ensure reliable service.

This idea would include specific new efforts such as the E+ rate phase out on VI, introduction of time-of-use rates, smart water heaters, and other ideas presented in this workshop. The current Power Smart Conservation Potential Report calls for 700 GWh and 125 MW of peak reduction over 10 years, at an average utility cost of $25/MWh. It should be possible to further reduce peak demand by an additional 75 MW over the same 10 years (see the idea description on time-of-use rates), for a total of 200 MW. Also, another 100 MW to 150 MW of load from water heaters could be shifted to off-peak periods (see next idea description), for a total reduction of 300-350 MW. Fuel savings are estimated to be 7.3 GJ gas/MWh. Environmental improvements would be located upstream close to generation, and is estimated to be 0.37 tonnes CO_2/MWh from reduced plant operation.[7]

Possible market risks include declining gas price and/or increasing cost of trade labor on VI. Possible barriers to achieving the additional peak reduction may be customer resistance, for example to the water heater load control, customer awareness of efficiency benefits, the accessibility of efficient and load management products, and the affordability of the products. BC Hydro has the ability to design programs such that these barriers are overcome. BC Hydro would need to determine the value of capacity on VI before implementing the peak reduction plan.

[7] Assuming the marginal generation source is a gas-fired combined-cycle plant with a heat rate of 7.3 GJ/MWh. Since the carbon content of natural gas is 51 kg-CO_2/GJ, the CO_2 emission intensity of saved electricity at the margin is 370 kgCO_2/MWh, or 0.37 metric tonnes CO_2/MWh. If the marginal resource is less efficient, the emission savings would be greater. If some non-fossil generation is also at the margin, the emission savings would be less.

Smart Water Heaters

NEXT STEPS: Field Study

Vancouver Island's load profile includes a demand peak in the morning as people head off to work and another peak in the evening. The evening peak is mostly due to lighting and cooking, plus heating in the winter. The idea is to install time-control shut-off switches, which will delay water heating until midday, after the morning peak that occurs during the 8am to 11am period.

The possible gross benefit to BC Hydro of this idea is $150 million. The amount assumes that 150MW can be shifted valued at $1000/kW. Each household might save $450, and BC Hydro could give each a $200 installation incentive plus $100 to help cover the upfront cost of the hardware. Assuming that water heaters average 4.5 kW, and that one-third are in use during any given peak period, this cost corresponds to $200/kW saved. To improve the reliability of peak demand savings, BC Hydro could charge $20 in liquidated damages for each customer override incidence.

The time frame for the project would be six to ten years, because electric water heaters generally last about ten years, and the controls could be built into the new heaters. In-line timers on the wires into the heater are an available technology. It is generally easier to retrofit new units at the shop than in customers' houses. To accelerate the learning process, BC Hydro could start a pilot program immediately with perhaps 100 households. BC Hydro would probably need to perform a one -year study to capture the total seasonal variability. In 1997 West Kootenay power implemented such a program. BC Hydro may be able to learn from their experience.

This idea would complement two other BC Hydro ideas: Developing a time-of -use rate strategy for residential and commercial sectors and controlling peak demand growth on VI. This could be an alternative to fuel switching of water heaters on VI.

Possible barriers to the successful implementation of this program include:

- Opposition to changes,
- Cost of meters
- Low electricity rates
- Need to establish time-of-use rate structure
- Need for technical infrastructure
- Need for a business plan

Additional questions:

- Is advanced metering required to establish time of use rates? GVRD is putting in new water meters – perhaps BC Hydro should piggyback this with the installation of inline water heater timers and time-of-use meter technology.

Temporary Curtailment of Pulp and Paper Mills

NEXT STEPS: Determine how many MW will be needed
Negotiate price w/ mills
Apply first contingency criterion based on transmission line failure

This initiative would free up capacity on VI during critical periods by encouraging the large pulp and paper plants at Crofton, Port Alberni and Campbell River to temporarily curtail their load at times (e.g. winter) of high demand for 2 weeks or more. This idea would include paying the mills for approximately two weeks paper storage on site to avoid revenue loss during the load curtailments. To further reduce costs, the mills could plan their annual maintenance shutdowns to correspond with one or more of the load curtailment periods, provided that the mills prepare to do the maintenance on relatively short notice when the shut down occurs. The mill owner might be persuaded that the inventory could be sold to the commodity market when prices are high.

Load curtailment would result in several benefits. It would bolster service reliability to other customers on the island. Also, natural gas consumption would be reduced during pulp and paper load curtailment. Efficiency improvements and distributed generation both on site and elsewhere in the BC Hydro system would reduce the amount that would need to be curtailed. Also, time-of-use rates could make demand more price-responsive in the long term.

BC Hydro could pay a mill to shut down parts of its plant on short notice. Also, BC Hydro could offer incentives to keep extra paper products in storage at a cost that would cover the mill's capital costs, which are approximately $20/kW. Given that the curtailment potential is probably around 300MW, the total cost of this idea would be about $6 million. Gas savings from this effort might amount to 10,000 GJ/day (out of a total 20,000GJ/day demand). Also, the mills could store wood waste for use in additional power generation during the winter periods. Because such a program could include sending employees home for unplanned vacation during curtailment., operational costs could be substantial and would need to be investigated further.

Of course, this idea would need the support of mills. That support is mostly likely if the mills are thoroughly involved in further development of the idea. Their early involvement will ensure that the idea works well for them. Also, it will significantly increase the potential that the mills feel that the idea is as much theirs as BC Hydro's. BC Hydro would need to determine how often curtailment would be triggered. Power Smart would then need to talk to the mill owner(s) and negotiate the 300MW curtailment.

Additional questions:

- This option might not offer the same reliability as a 300MW generator connected throughout the year. There could be unforeseen circumstances and multiple contingencies.
- Previous studies found it was worth about 1/5 of a generating system of the same size, though this assumes only a one-time occurrence per year. A critical component of this idea is the appropriate decision about when the particular time for curtailment has arrived. Once stored inventory has been fully depleted, another curtailment can't be repeated for the rest of the season. The capacity benefit of this idea is derated 80% because it does not meet the full contingency criteria.

Generation and Distributed Resources

BC Hydro's primary strategy for resolving the urgent need to increase its power delivery capacity to VI is the VIGP and GSX proposals. Assuming that these projects are completed as planned, VI might need additional generation capacity in the future to serve load growth or replace retired assets. On the other hand, if VIGP and GSX are not completed, BC Hydro will need contingency plans that include new generation. While energy efficiency and load management can mitigate future load growth and provide flexibility in operating the island's power supply system, these resources alone cannot replace the firm capacity now provided by the aging transmission infrastructure. Supply side solutions are also needed.

However, the VIGP and GSX proposals, and some of the proposed alternatives to these projects, represent only one of three basic strategies that BC Hydro can use to address the potential VI capacity shortfall through generation and distributed resources. With the ending of BC Hydro's historical monopoly over supply-side resource procurement, any of these strategies will have to be implemented by the private sector on a competitive tender basis.

The full range of options includes the following strategies:

1. Increase *on-island generation capacity*, such as VIGP, and fuel supply, such as GSX.
2. Increase *Mainland generation capacity*, together with transmission capacity to Vancouver Island and possibly on the Mainland.
3. Increase on-island *distributed resources,* such as cogeneration, energy storage and certain renewable sources.

The VIGP and GSX proposals (strategy 1) are well advanced in the regulatory approval process, and BC Hydro management is committed to completing these projects once they have been fully approved. Thus, VIGP/GSX was not treated as a new option at the workshop, which focused on longer-term options and to some degrees on alternatives in case VIGP/GSX is not approved. At the workshop, the group reported in detail on proposed ideas related to distributed resources (strategy 3), discussed below:

Energy storage on VI
Cogeneration using natural gas or biomass
Tidal, wave or wind power on VI

Note that the implementation of strategy 2, increased *generation on the mainland*, depends on the development of additional transmission capacity between VI and the Mainland as well as on relieving transmission constraints on the Mainland. These options are discussed under Transmission and Distribution Grid Solutions. The Mainland generation option that was most discussed in the workshop is *re-powering the Burrard steam turbine plant with CCGT technology* to increase its capacity and efficiency, while making use of the existing site, switchyard, etc.[8]

[8] Possible shepherd for continued discussion: Glen Smyrl

Distributed Resources

The full benefits of distributed generation should be more apparent on Vancouver Island, due to its comparative geographic isolation, than on most other areas of BC Hydro's system. Most utilities value distributed generation based on standard economic calculations of system-wide capacity and energy value, adjusted for lower line losses. RMI's perspective on distributed generation is that in addition to these benefits the most valuable distributed benefits can flow from three primary sources:

- Financial economics, including the lower risk of smaller modules with shorter lead times, portability, power market hedging (from demand response), and, if renewable sources are used, the elimination of fuel price volatility
- Electrical engineering benefits, including lower grid costs and losses, better fault management, voltage and reactive power support, and lower transmission and distribution operations & maintenance
- Reliability benefits if the distributed source can run in an "island mode," including avoided business interruption costs, lower probability of grid failure, and faster recovery time for the grid in the event of grid failure

Collectively, these additional benefits can increase the actual economic value of distributed generation from 3-5 fold. In total, we have found over 207 distinct benefits that are attributable to distributed resources.[9] Therefore, RMI's view is that it is imperative that BC Hydro correctly value the distributed resources when comparing them to the alternatives, particularly reliance on transmission of mainland generation resources.

Getting The Most From Gas

Due to its geographic isolation, Vancouver Island is fuel limited. Thus, an underlying issue for BC Hydro is to define the energy strategy that extracts the greatest value for the customers from the existing and future gas deliverability. Given the high heat loads on Vancouver Island, the question is whether direct heating from gas appliances would be more energy efficient and economically efficient than generating electricity, transmitting it to the end user, and then converting electricity to heat. The system efficiency of the direct gas energy pathway is 85-97%, whereas the system efficiency of the electric heating pathway is only about 50%, assuming CCGT generation (or about 35% with simple-cycle generation). Therefore, the energy efficiency of the direct gas-to-heat pathway is almost twice that of the most efficient electric pathway at the margin.[10]

The same issue applies to distributed generation. Will BC Hydro get the most value from using the available gas to power a combined-cycle gas turbine (CCGT) unit, or would BC Hydro be better off with a series of smaller cogeneration or combined heat and power (CHP) units. The

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[9] Described in an *Economist* Book of the Year: *Small Is Profitable* (www.smallisprofitable.org).

[10] The average efficiency of the electric heating pathway could be improved by using a heat pump at the end use. However, at peak demand during cold winter weather, a conventional air source heat pump would switch to resistance heating mode to prevent the evaporator coil from freezing, resulting in at least as high peak demand as resistance heating.

total thermal and electric efficiency of CCGT is rarely more the 50%, whereas combined heat and power units have a 60-80% thermal efficiency, depending of the thermal load factor.

The difference in capital cost and fixed O&M between a combined cycle unit and cogeneration can be recovered from the fuel cost savings (when gas costs are greater than $ 4.5/GJ), before even counting the distributed benefits. The reason that cogeneration does not have greater penetration on BC Hydro's system is due more to pricing (cheap regulated electricity vs. expensive deregulated gas) than the underlying economics of the resource choices.

Utilizing the Potential Primary Energy on Vancouver Island

With transmission capacity deteriorating, and gas resources limited by gas transmission capacity, then utilizing the potential primary energy on Vancouver Island is necessary. *Vancouver Island has hydropower, biomass, wind, tidal and wave energy resources*. Much of these resources are in the northern part of the island. Improvements to the transmission system are likely required to transmit electricity from the northern to southeast part of the Island. Therefore, the renewable resource costs must also include the delivery costs to access the load centers in the southern part of the island. Traditionally, the incremental cost of transmission capacity to serve such sources would be assigned to each new source individually, making it prohibitively expensive. However, if the *transmission extension policy can be modified* in such a way that these costs are shared among multiple sources and spread over time, on-island renewable power would be more viable.

Also, renewable resources tend to be intermittent and need to be "firmed" either by using hybrid plants with fossil fuel backup or combining them in a generation portfolio. *A firm portfolio can be assembled from non-firm resources* if their production profiles balance each other.

For example, pumped-storage hydropower has proven to be a cost effective resource for firming renewable resources, and pumped hydro sites exist on Vancouver Island. The technical potential is large enough that this resource portfolio should be given serious consideration by BC Hydro. In order to be licensed on Vancouver Island, pumped storage would probably need to be closed loop, where the upper and lower reservoirs are constructed as part of the plant and water is only released to, and taken from, the environment during start up and maintenance.

Because these remote, intermittent renewable resources are not dispatchable or load following, and because they tend to increase rather than decrease transmission needs, they do not provide many of the distributed benefits described above. Indeed, these sources are more like central resources than distributed resources. However, do provide the economic (fuel price hedging) and environmental (emission reducing) benefits by virtue of being independent of fossil fuel.

Implications to Vancouver Island and BC Hydro

The implications to BC Hydro are clear. There is untapped potential of distributed and renewable resources on Vancouver Island than could be forged into a viable resource portfolio that would deliver firm capacity and energy at moderate cost. Such a portfolio could complement the VIGP/GSX project, or provide part of a contingency plan in case it is not completed.

The underlying economics of distributed generation (particularly cogeneration) could make it the least-cost option when the full avoided cost, risk management and reliability benefits are included. Regarding renewable sources, present needs are to pilot promising new technologies, such as tidal energy, to consider modifying the transmission extension policy regarding new generation sources, and to begin creating "firmed" portfolios of renewable projects.

Energy Storage for VI

NEXT STEPS: Identify costs for each storage technology
Identify existing storage capability
Identify the value of storage
Possibly contract out for the research
Integration with Resource Plan
Look at integration with H_2

Vancouver Island currently has little energy storage capacity, even with several (seven) existing hydroelectric dams. Hydroelectric storage potential has not been explored in detail; it appears that the potential is fairly small, especially if existing dam heights do not change. However, other energy storage technologies are available, including: pumped storage hydro, flywheels, batteries, fuel cells, compressed gas, direct hydrogen storage, and thermal energy storage combined with heat recovery chillers for buildings that could be made available to the island.

The benefits of having more energy storage capacity include support of load shifting and peak shaving options that Power Smart may pursue in their new effort to focus on controlling peak demand growth on VI. Energy storage would allow facilities that defer consumption during peak periods to use their equipment or appliances during off peak periods. Another benefit is to increase system reliability by firming up intermittent renewable generation sources that may be installed on the island in the future, such as wind, biomass, wave, tidal, and solar. Energy storage technologies can also provide ancillary services such as voltage support and spinning reserve. Finally, storage, especially in the form of fuel cells and hydrogen, would complement the idea of using barges, ferries, and other floating vessels as mobile generation sources for VI and the mainland.

BC Hydro currently has little in-house expertise on energy storage technologies other than pumped storage hydro. Basic research is needed to learn more about specific energy storage technologies, their technical and economic performance, available capacities, storage life, equipment life, and environmental impacts. BC Hydro will need to explore in more detail existing energy storage capabilities on VI. One idea mentioned was to increase the dam height of the existing reservoir on the Jordan River. Nexen Chemical's sodium chlorate plant near Nanaimo on VI produces hydrogen as its by-product. It would be a cheap source of hydrogen for setting up an initial pilot program on hydrogen storage for the island.[11]

Initial barriers identified include the possible high cost of energy storage at today's prices. Perhaps a subsidy program would need to be created that would allow benefit/cost sharing between BC Hydro, IPPs, and other third party partners.

[11] The recently announced Climate Action Plan includes funding commitments of $80 million for fuel cells and other technologies relevant to an emerging hydrogen economy.

Cogeneration

NEXT STEPS: Investigate rate and price structures.
If necessary, find additional gas required for cogeneration on Vancouver Island.
Initiate DSM – efficiency and / or load shifting – for natural gas.
Increase compression on existing pipeline.

Cogeneration is the simultaneous production of electricity and steam heat. This idea proposes to add electricity generation capability to existing facilities that have significant thermal loads and already purchase natural gas for heating. Thermal heat loads make cogeneration highly efficient, typically 80% thermal efficiency, with incremental heat rates between 4,500 and 5,000 Btu/kWh. Potential markets include commercial buildings, industry, hospitals, universities, and other institutional buildings and campuses.

Cogeneration on VI might add 300 MW of peak capacity from large-scale industrial installations and probably 20 MW total in small-scale installations, and annual generation of 2,000 GWh. Fuel requirements will be site specific. Cogeneration can contribute to system reliability, especially if the generation capacity is directly linked to the load (the two can move up and down together). However, there is a risk that cogeneration owners may shut down in the event of decreased market activity (e.g. decreased demand for pulp). This reliability concern would need to be addressed contractually.

The primary barrier to realizing Vancouver Island's cogeneration potential is the current pricing structure for power. Under the current pricing structure, the rates charged to small and medium industrial, commercial and institutional customers are insufficient to justify private sector investment in cogeneration ($31/MWh plus $6.4/kW-month demand charge). The prices offered by BC Hydro to purchase electricity from IPPs, particularly on-peak, may be too low to encourage new cogeneration. An adequate price offer would take into account both location and time of generation.

Cogenerators are exposed to fuel price risk in their power contracts with BC Hydro. The allocation of gas price risk may also be asymmetric. When BC Hydro uses natural gas to generate electricity, the gas price risk is passed on to consumers. In the case of cogeneration, the industrial partner or IPP takes on the gas price risk. To encourage cogeneration, BC Hydro could consider entering into tolling agreements with small IPPs, and passing the fuel price risk through to rates. If fuel price risk is passed through, it is still likely that a small cogeneration plant on the gas distribution system will pay more for gas than a large CCGT plant on the high-pressure gas system. Thus the appropriate economic analysis is whether the benefits from improved thermal efficiency offset the higher gas, capital and O&M costs.

If additional gas transmission to the Island is not built, another possible barrier to cogeneration is availability of gas on Vancouver Island. Therefore, it may be necessary to find additional gas for cogeneration on Vancouver Island via a combination of DSM – efficiency and / or load shifting – for natural gas as well as increasing compression to allow greater throughput in the existing pipeline.

Barriers may also exist in the organizations that could potentially invest in cogeneration. Another possible barrier is disinterest among potential institutional investors who may regard cogeneration as outside their core business, who may not understand cogeneration, or who lack planning tools with which they might understand, for example, payback periods. The distinction that BC Hydro draws between self-generation and cogeneration was also identified as a potential barrier.

Another idea that was proposed but not developed further: Biomass generation or cogeneration on VI.[12] An existing proposal is the Gold River biomass project at the Bowater mill site, which would have a capacity of 30 MW to start (using existing boilers) and the potential for up to 250 MW. The Gold River proposal calls for the import of wood waste materials from all along the West Coast. Although not explored further in the workshop, biomass could also fuel distributed cogeneration projects at industrial and commercial customers sites on VI.

[12] Possible shepherd for further discussion: Steve Watson

Tidal, Wave, or Wind Power on VI

NEXT STEPS: Resume discussions with private sector proponents to develop a Federal/Provincial/BC Hydro team to scope out funding for demonstration project.

Tidal power is an enormous resource around Vancouver Island, which has some of the best sites worldwide. Most of BC's tidal resource is located near the Queen Charlotte Islands and around V.I. Based on the study performed by Triton Consultants the total resource on VI exceeds 2 GW. The study assumed an average 3.5 m/s tide velocity and estimated a cost of 11c/kWh. However, Amory Lovins suggested that if the top seven sites were developed (2/3 of the ~2GW potential) the cost would be closer to 5 c/kWh (power increases by the cube of tidal velocity). The tides at some top sites, however, are so strong that existing turbine technology would be unable to withstand the forces generated. This is a technical barrier that can eventually be overcome.

As tides are a function of the orbits of the sun and the moon, they are extremely regular and can be predicted centuries into the future with great precision. Though they vary significantly through any given day, if several sites are developed, power can be phased into the electricity grid, taking advantage of energy peaking at different times at different sites. As a result, tidal current turbines can generate consistent supply. Based on tidal modeling studies, environmental and physical impacts of tidal current power generation are expected to be small.

Tidal power is a promising technology. There are four to five concepts being developed currently; one to three models are being commercialized in the U.K. and elsewhere. It is considered cost-effective by some U.K. authorities. Technical reliability can be high if well engineered for the marine environment. Tens of kW are generated per linear meter of tide and the resource is steady and predictable. For technologies that rely on tidal currents, generation is based on velocity rather than head, and the technology is similar to run-of-river turbines. The technology is clean and would therefore displace the emissions of the fossil-fired generation it displaces.

An initial estimate of energy generation is around 3.5 TWh at a 20% capacity factor. This is probably a conservative estimate given that total energy potential is estimated at 26 TWh/yr at a site with greater than 2 m/s average velocity. BC Hydro could test a pilot plant. A first unit could cost as much as $200/W. However, Verdant power (www.verdantpower.com) has a 10MW test unit currently being developed in the East River off Manhattan in New York City that is similar to the technology that BC Hydro might construct. Since the enormous tidal resource is located north of VI's energy consuming population, transmission upgrades and possibly new investments will likely be needed. Also, navigational and other marine issues (e.g. marine mammal and fish safety) would have to be resolved.

In addition to supplying electricity to consumers, tidal power would complement hydrogen generation. Hydrogen would serve as an energy storage medium for other renewable resources on the island. Because the resource is so large, BC could potentially develop an entire industry around it, becoming the world leader in tidal power technology,[13] as Denmark has done with wind power.

Wave power is related to tidal power and also is a large resource around Vancouver Island. Wave power is predictable a few days ahead, although energy performance is very site dependent. The technology is expected to be cost effective in the kind of wave regime that exists off VI.

As in the case of tidal power, BC could develop an entire industry around wave power technology, integrating the technology with hydrogen and other renewable technologies. Bruce Sampson will resume discussions with proponents to scope out the costs for demonstration projects. The private sector and/or government could fund the difference between avoided generation costs and actual costs. BC Hydro could offer a green contract equivalent for non-commercial alternative energies. It could be a fifteen to twenty year contract at approximately 5 c/kWh. This would be less the risk-adjusted gas price delivered for VIGP/GSX.

Wind power appears to have significant potential in the northern part of VI. The potential is estimated to be up to 650 MW in areas with average wind speeds of 8 m/s, where a capacity factor of 35% or higher can be achieved. Unlike tidal and wave power, wind power is a mature technology, with about 7000 MW of new capacity installed worldwide during 2002.

On the other hand, variations in wind speed and power production are less regular and predictable than for wave and tidal power. Therefore, other resources such as pumped-storage hydro are useful to provide "firming" of the wind power. The wind resource on VI does appear to be stronger in the winter, when peak demand occurs, raising the value of the energy produced.

Some prospecting has been done on VI to identify high-potential offshore wind sites, where the (visual) environmental impact would be reduced. For example, a large offshore wind power project is under development for connection to the Mainland near Prince Rupert. There appear to be few offshore sites on VI with both strong winds and a shallow seabed, so onshore resources appear more promising on VI.

[13] For example, BC could develop a research program around biomimetic turbines modeled around the inside of sea turtle shells (see www.paxscientific.com). The flow of seawater inside and through these shells is a vortex laminar flow that is super efficient and does not harm fish that swim through it. Designing a turbine to move fluid in this way would also take advantage of its inherent efficiencies. (Current fluid handling equipment is designed around turbulent flow).

Transmission and Distribution Grid Solutions

The gradual deterioration and derating of the existing HVDC transmission lines to Vancouver Island are the main cause of BC Hydro's urgent need to increase its power delivery capacity to VI, either by additional transmission, on-island generation, or both. Indeed, even the generation solutions depend on adequate transmission and distribution capacity to reach customers.

The four basic strategies that BC Hydro can use to address the potential VI capacity shortfall through transmission and distribution grid solutions are the following:

1. Increase the *transmission capacity between Vancouver Island and the Mainland*. This can complement or substitute for on-island generation.
2. Improve the *operation of the transmission and distribution grid* on Vancouver Island. This can reduce losses and free up capacity to serve loads.
3. Increase the *transmission and distribution capacity available on Vancouver Island*. This can enable the interconnection of on-island renewable generation resources.
4. Increase transmission capacity to *relieve potential constraints on the Mainland*. This can enable additional VI load to be served with Mainland generation capacity, if transmission capacity between VI and the Mainland is increased.

At the workshop, the group reported in detail on proposed ideas, discussed below, that relate to strategies 1, 2 and 3 above. These are:

Convert Dunsmuir-Sahtlam line from 230kV to 500 kV
Real time metering to reduce line losses
Modification of transmission extension policy

Note that the implementation of strategy 1, increased transmission from the Mainland, depends on the development of both *new generation sources on the mainland*, as well as on strategy 4, relieving transmission constraints on the Mainland. Mainland generation is discussed briefly under Generation and Distributed Resources.

Also, strategy 3, increased transmission on VI, together with modification of the *transmission extension policy*, is probably a necessary prerequisite for realizing much of the *on-island renewable generation* potential that was identified. This proposal is also discussed in more detail below.

Convert Existing 230 kV Dunsmuir-Sahtlam Line to 500kV

NEXT STEPS: Planning study to determine requirements, benefits, and costs

Currently the 500 kV transmission line that runs north-south from Dunsmuir (near Qualicum) to Sahtlam (near Duncan) on VI is being operated as a 230 kV system. Converting the system to run at its true, higher capacity would decrease transmission losses, increase transmission reliability, and significantly increase the north to south transmission capacity on the island. The upgrade would also facilitate the planning and siting of VI's abundant renewable energy resources or other IPP proposals, many of which are located in the northern areas of the island and bring energy south to where the population is concentrated.

The conversion of the line to 500kV operation would provide approximately 100 to 300 MW in additional transmission capacity, and eliminate 20MW in losses resulting from the 230 kV rating. Altogether, this would increase the transmission capacity by approximately 30-50MW and save 87,600 GWh/year of energy.[14] This conversion is likely to happen, especially if new generation is added north of (Qualicum) Dunsmuir. The project cost would be around $40-$50 million for substation modifications over three to four years. The investment would be repaid by the energy savings from 20 MW (10 MW average) loss reduction.

In order for this idea to become reality, BC Hydro and BCTC staff will need to continue their planning efforts, including defining future generation needs and new plant locations. The significant investment required may require BCUC approval.

Another idea that was proposed but not developed further: Convert the existing system to DC operation. This could also double capacity, so either cable in the first contingency pair could handle the entire VI load, possibly at less cost than increasing AC capacity. The main weakness is that the capacity increment is too large to allow it to be out of service long enough to implement the conversion. This would take more time and money than replacing terminals on existing HVDC lines, but that step could possibly buy time for this one. It would be necessary to develop detailed information on system stability issues related to the conversion.

[14] Assuming a 50% capacity factor on the transmission lines.

Line Loss/Theft Reduction Via Real-Time Meters at Substations and Distribution Transformers

The idea involves the installation of new meters at or near residences and transformers with the ability to better measure actual electricity usage in real time. The idea also complements Power Smart's new effort to manage peak demand growth on VI through such measures as time-of-use rates for commercial and residential customers, and remote and smart metering.

Benefits from the installation of new and smart meters include an estimated 120 GWh/ year savings from theft prevention, and approximately 700 GWh/ year savings through customer change in behavior. BC Hydro anticipates a 10% savings from spontaneous customer behavior change from the availability of detailed analysis of time of day usage due to the meters. Capacity reduction from implementing the project could be 60-88 MW. Using a CCGT as a proxy, potential savings of 14 TJ/ day and 300,000 tonnes of CO_2 savings per year could be possible.

A rough approximation of project cost is $100 million amortized over 20 years for installation of meters. This assumes that meter readers can be eliminated or changed to new meters. Risks are assumed to be small to none, while the benefits include energy and emissions savings, and improved system reliability. Additionally, smart meters would allow for better load analysis and transfer capability, more efficient investments from planning and design, and better information for the development of DSM programs that target specific technologies to manage peak demand.

Modification of Transmission Extension Policy to Enable Renewable Generation

NEXT STEPS: Develop business case, including possible incentives
Determine marginal cost of new supply on VI

Connecting new green independent power producers (IPPs) on VI, particularly wind, wave and tidal power, will be difficult and possibly prohibitively expensive if these sources require additional transmission capacity. In the BC Hydro system, customers connect to the transmission system (69 kV and higher) for the following reasons:

1. The load is large enough (>5 MW) to justify the higher upfront cost of installing a substation and building a transmission line to the substation.
2. The site is remote and the transmission system is the closest point of connection.
3. For an IPP, the generator is large enough that it cannot be connected directly to the distribution system. A distribution feeder at 25 kV can only carry 10 MW to 15 MW.

If an IPP wants to connect to the transmission system, they have to pay BC Hydro (or soon the BC Transmission Company) to study the impact of connecting the generation source to the grid. The study determines what type of protection and control technology is required for the IPP to operate safely and prevent negative impacts on the system. From such studies, the IPP will be told what the costs are to connect to the system.

The IPP must also do their own study on building the transmission connection from the location of their plant to the existing BC Hydro transmission system. The IPP has the option to build this extension to BC Hydro's standards or to build it to a different standard to reduce costs. Usually they build to BC Hydro standards, in which case the IPP can turn over the transmission extension over to BC Hydro/BCTC to own, operate and maintain. In some cases, for example mines in remote locations, IPPs have built to a different standard to save costs. These IPPs own and operate their own line, and they must also construct a substation that steps the voltage to that of the transmission system.

If a customer pays for the transmission extension and a second customer later connects to this extension, then the first customer is paid a prorated amount from the second customer, based on the depreciated value of the portion of the extension the new customer is using. However, BC Hydro charges the new customer the replacement cost of the portion of the extension they are using. However, if a line is built to serve an IPP it would be sized for that IPP. If other IPPs come later, they may find that there is no capacity. If it is known when the line is designed that there are other viable projects in the area, then it would make sense to size the line to accommodate all the IPPs.

Thus, for a small IPP to locate in a remote area the cost to connect to the BC Hydro system can kill the economics of the project. There is a "Chicken and Egg" situation in that, if the line is in place, the projects would go ahead. However, the line will not go ahead unless the projects are there to justify it, and no single project can bear the cost of the line.

A possible solution would be to gather enough IPPs that could build projects in an area that would be served by a transmission line, so that the cost of the line can be shared between the various projects. This would require a change to the BC Hydro extension policy and collaboration with the Provincial government to support the aggregated development of multiple renewable generation projects. Such support could include low-cost loans or contingent grants to cover the initial development costs, such as the necessary interconnection studies.