August 30, 2017
Site C Inquiry
British Columbia Utilities Commission

We wish to make the following submission to the Site C Inquiry.

Exhibit A-2 of the Site C Inquiry references Order Number G-120-17 which includes the following:

A.

On August 2, 2017, the Lieutenant Governor in Council, by Order in Council (OIC) No. 244, requests the British Columbia Utilities Commission (Commission), pursuant to section 5(1) of the Utilities Commission Act (UCA), to advise the Lieutenant Governor in Council respecting British Columbia Hydro and Power Authority's (BC Hydro, the authority) Site C project in accordance with the terms of reference set out in section 3 of OIC No. 244 (Site C Inquiry). OIC No. 244 specifically requests that the Commission provide responses to the following questions:

. . .

4.

Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?

. . .

NOW THEREFORE pursuant to section 5 of the Utilities Commission Act, the British Columbia Utilities Commission orders as follows:

. . . .

2. The Site C Inquiry will not include registered interveners. The Commission invites members of the public to make submissions of data and analysis that are relevant to the scope of the Commission's Site C Inquiry on or before August 30, 2017 for consideration in the Commission's Preliminary Report.

The "Site C Inquiry Making Submissions" section on the Site C Inquiry website notes that questions before the BCUC include:

d. what portfolio of generating projects and demand-side management initiatives could provide similar benefits; and

We wish to submit the 3 attached documents and these introductory comments as our submission of data and analysis. We suggest that these documents are relevant to the scope of the Site C Inquiry as defined in Item A(4) of Exhibit A-2 and Terms of Reference.

These attached submissions were presented to the BCUC Section 5 Transmission Inquiry (Section 5 Transmission Inquiry C-58-2, C-58-3, C-58-4) by Mr. Ludo Bertsch on behalf of ESVI, OEIA, ITO and ROMS BC. That Inquiry was halted in 2010 (Section 5 Transmission Inquiry Exhibit A-38).

Submitted by:

Ludo Bertsch, P.Eng.
Horizon Technologies Inc.
On behalf of ITO (IslandTransformations.Org)

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Section 5
BC Transmission Inquiry

Comments
on Scope of the Inquiry

by: ESVI, OEIA, ITO and ROMS BC

By: Ludo Bertsch, Horizon Technologies Inc.
[redacted]
Date: June 11, 2009
For: ESVI, OEIA, ITO and ROMS BC

Summary

The following document are comments relating to defining the scope for Section 5 Transmission Inquiry in response to Exhibit A-12.

Yours truly,
Ludo Bertsch, P. Eng
Horizon Technologies Inc.
bcuc@horizontec.com
[redacted]

Representing:
- Energy Solutions for Vancouver Island Society (ESVI)
- Okanagan Environmental Industry Alliance (OEIA)
- IslandTransformations.Org (ITO)
- Rental Owners and Managers Society of BC (ROMS BC)

1.0 **Assessment of Generation[1]:**

1.1 Feed-In Tariffs

Commission staff distributed a discussion paper Exhibit A-12[2].

The paper stated: "***Developing*** *technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation from wind, solar, wood waste or tidal resources.*"[3] [***emphasis added***]

"*Information on* ***all existing electricity resources****, including any anticipated changes that may occur, such as Resource Smart projects and end-of-life estimates with or without life extension projects.*"[4] [***emphasis added***]

Distributed renewable generation at the customers location that output excess power to the grid not only reduces the demand of the customers, but also reduces the transmission and distribution requirements for those customers and their nearby neighbours. Jurisdictions such as Germany, Denmark, Spain, Australia and Ontario have incentive rates, called "Feed-In Tariffs", as a key strategy to encourage renewable generation and increasing its participation. In addition, with many other jurisdictions, including the United States, are in various stages of approving Feed-In Tariffs.

At present BC Hydro has a Net Metering program, and FortisBC is in the regulatory process of adding Net Metering. We believe that Feed-In Tariffs may very well be introduced to BC in the near future.

Therefore, we suggest that the Transmission Inquiry should include Feed-In Tariffs and distributed generation in the scope of its investigation. Although the majority of this work would qualify as "*developing technologies*", in some ways this could also be considered an extension of the "*existing electricity resources*", e.g. Net Metering.

We have included this discussion within the "*Assessment of Generation*" section because it was originally presented by Commission staff in the Generation section, although we recognize that it could also be considered within the "*Assessment of Demand*" section.

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[1] Exhibit A-12, Pages 1 to 3
[2] Exhibit A-12
[3] Exhibit A-12, Page 2
[4] Exhibit A-12, Page 2

1.2 Wave and Tidal

We note that the Commission staff paper discussed "in scope" issues:

> "*Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation from wind, solar, wood waste or* ***tidal resources****.*"[5] [***emphasis added***]
>
> "***Ocean (wave and/or tidal current) power*** *or carbon sequestration from coal generation becomes cost-competitive.*" [6] [***emphasis added***]

We recognize that the tidal and wave power systems are costly energy sources for BC at this time. However, within the Transmission Inquiry timeframe, the technology gains in turbines combined with the geographical advantages of a large coastline of mainland BC/Vancouver Island and strong currents will mean that both tidal and wave power systems could become viable and we support the Commission's staff position of including these in scope for the inquiry.

From the wording in the Commission staff paper it is not clear, if systems in which turbines are placed in the middle of a stream and convert the kinetic energy to electricity, are considered in scope.

The BC Ministry of Energy, Mines, and Petroleum Resources has defined Clean or Renewable Electricity in a document (see attached[7]). To ensure a common understanding of the terms, we suggest that reference be made to this document. We also suggest that "hydro" be added to the list, which is defined as "*electricity generated from a system or technology that converts either the potential or kinetic energy of water*". To differentiate from older "hydro" technologies (using dams), we suggest "in-stream" be added. Therefore, we suggest the new sentence on page two would read:

> "*Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation from wind, solar, wood waste, tidal* ***or in-stream hydro*** *resources* ***(as defined by BC Ministry of Energy, Mines, and Petroleum Resources in the attached definition of Clean or Renewable Electricity****). [****emphasis on additions****]*

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[5] Exhibit A-12, Page 2

[6] Exhibit A-12, Page 2

[7] "British Columbia's Clean or Renewable Electricity Definitions"; *http://www.empr.gov.bc.ca/EAED/AEPB/Documents/CleanEnergyJune.pdf*

1.3 Solar and wind

We note that in the Commission staff paper discussed "in scope" issues:

> "*Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation from* ***wind****,* ***solar****, wood waste or tidal resources.*"[8] [***emphasis added***]
>
> "***Wind*** *emphasis – regional generation favouring* ***wind*** *advantage*"[9]

We support the Commission staff's inclusion of wind and solar in scope, and suggest that the regional aspect of wind be expanded to include the regional considerations for solar. There may be regions such as the Okanagan that can benefit more from solar resources than other regions.

In addition, we suggest that clarification be added that the wind and solar resources not only cover farms, but also individual customer generation as discussed in the "Feed-In Tariffs" section.

1.4 Regional generation

We note that in the Commission staff paper discussed "regional generation":

> "*Staff further propose that* ***regional generation*** *estimates be used as the basis to develop a range of cost forecasts for generation by region, and to assist in determining the most cost-effective and probable sequence(s) of development, and therefore the need for transmission development.*"[10] [***emphasis added***]

We believe that this inquiry should be developed as an integrated process, one in which generation, demand and transmission are considered in an integrated approach – this is further discussed in the "Integrated Approach" section (section 4 of this document).

One of the outcomes of analyzing with an Integrated Approach results in following situation . . .

> Staff suggests developing a range of cost forecasts for generation by region. We suggest that one of those cost forecasts within the "*range*" to be considered should be "*no more Transmission Lines to Vancouver Island*". We suggest this is one of the reasonable cost forecasts that should be

[8] Exhibit A-12, Page 2
[9] Exhibit A-12, Page 2
[10] Exhibit A-12, Page 3

explored, especially given the high cost and challenges of new transmission lines to Vancouver Island and the potential self-sufficient nature of the region.

Consequently, the cost of generation without more transmission lines to Vancouver Island would be explored and could be compared to adding more transmission lines to Vancouver Island.

To further explore the Integrated Approach, another question we suggest be explored within the Inquiry – what generation and **demand side management** levels would need to be implemented such that "*no more Transmission Lines would be needed to Vancouver Island*"?

We suggest that this discussion of Vancouver Island be added to the "Integrated Approach" section of this document (section 4).

2.0 Assessment of Demand[11]:

2.1 Smart Grid Scenario:

We note the Commission paper discusses:

> "*Agreement or Commission direction on a manageable number of demand **scenarios**, which are meaningfully different from each other, is vital to the Commission delivering useful determinations.*"[12] [***emphasis added***]
>
> "*In addition, forecast scenarios may need to be developed to reflect future outcomes that were **not adequately*** addressed *in the LTAP.*"[13] [***emphasis added***]
>
> "*The Terms of Reference recognize the need for **scenarios** and staff think it is important that a limited number of scenarios be used to group factors that may drive demand higher or lower to produce a viable number of options*"[14] [***emphasis added***]

We suggest the following demand scenario be included in the inquiry:

This scenario involves a full rollout of the Smart Grid implementation. Smart meters would be installed throughout BC, with appropriate rate structures such as time of use rates. A large number of utilities are

[11] Exhibit A-12, Page 3 to 6
[12] Exhibit A-12, Page 4
[13] Exhibit A-12, Page 4
[14] Exhibit A-12, Page 5

progressing toward the Smart Grid. The Canadian and US governments are providing significant stimulus packages to ensure that the next generation of the Electric infrastructure is smarter and more efficient than the last hundred years.

Well-designed demand/response mechanisms would be implemented with the understanding and sensitivity that customers are in control of their own homes. In other words, customers would have the choice on (and benefit of incentives) of whether or not to participate in utility management programs at critical peak times.

Products would include setback thermostats, smart water heating, and other smart appliances, in addition to being able to use a range of user-friendly display and control units.

Although Smart Meters are mentioned in the BC Hydro LTAP, the scenario described above is meaningfully different and has a reasonable opportunity of occurring.

2.2 Electric Vehicles:

The Commission staff paper states:

> "*The scenarios identified in the Terms of Reference considered heightened requirements arising from* ***fuel switching*** *to electricity as a greenhouse gas reduction strategy, and regional long-terms economic expansion."*[15] [***emphasis added***]
>
> "*New technologies such as* ***electric vehicles*** *and home electronics may increase demand, while conservation technologies may reduce demand."*[16] [***emphasis added***]
>
> "*High demand – high exports, high economic growth,* ***plug-in electric vehicles***"[17] [***emphasis added***]

The discussion of electric vehicles as presented by Commission staff are only discussed within the "Assessment of Demand" section and in the "High Demand scenario".

We note that electric vehicles can also serve as distributed storage, and their introduction at a large scale is significantly tied to time-of-use rates and the Smart Grid. Electric vehicles also provide significant shifts in greenhouse gases and is a major fuel switching strategy, while at the same bridging both

[15] Exhibit A-12, Page 4
[16] Exhibit A-12, Page 5
[17] Exhibit A-12, Page 5

transportation and energy sectors.

Therefore, we suggest that discussions relating to electric vehicles should not be tied only to demand, but should be a separate topic area dedicated only to "Electric Vehicles" and analyzed on an integrated approach which encompasses all areas relating to electric vehicles, including generation and transmission (we suggest this topic be added to the "Integrated Approach" section as discussed in section 4 of this document).

2.3 Demand Side Measures and 2007 BC Energy Plan:

With the emphasis from the province in the 2007 BC Energy Plan and the DSM Regulation M271 for placing ambitious conservation and energy efficiency targets to handle the incremental resources needs in BC, and pursue all cost-effective demand side measure. Since this will have a major effect on demand, and consequently the transmission requirements, we believe it is essential that a focus be clearly directed at demand-side measures in the Transmission Inquiry as well.

The Commission staff paper states:

> "*Reasonable forecasts of the province's domestic long-term energy and capacity requirements, based on estimates of net domestic demand, after provincial self-sufficiency requirements and* ***demand-side measures*** *are taken into account, are in scope."*[18]

The above statement clearly identifies the energy and capacity forecasts to be in scope, but it is not clear if the demand-side measure forecasts themselves would be in scope. To clarify, we suggest that it clearly be stated that the demand-side measure forecasts themselves be considered in scope.

The Commission staff paper also states:

> *"In addition, forecast scenarios may need to be developed to reflect future outcomes that were not adequately addressed in the LTAP."* [19]

Similarly, we suggest that these forecast scenarios specifically include demand-side measure forecasts.

We note that various plans are specifically identified through the Commission

[18] Exhibit A-12, Page 4
[19] Exhibit A-12, Page 4

staff paper, and in spite of the importance of the 2007 BC Energy Plan that it was not specifically noted in the Commission staff paper. We suggest that one of the "in scope" issues be:

- a complete analysis of the 2007 BC Energy Plan and M271 to determine the appropriate sections that would be relevant to the Transmission Inquiry.

3.0 **Assessment of Transmission[20]:**

3.1 Vancouver Island

As discussed in section 1.4, we suggest that one Transmission scenario that should be analyzed: "*no more Transmission Lines to Vancouver Island*".

Vancouver Island is a distinct region geographically, and involves significantly higher and more complex transmission connections. We suggest this be added to the "Integrated Approach" section as discussed in section 4 of this document.

3.2 Ties to Alberta and the U.S.

The Commission staff paper states:

> "*The review will include issues with respect to the capacity of the interties with Alberta and the U.S.*" [21]

We suggest that the discussion of the interties also include a discussion of the Smart Grid because of the high concentration of Smart Grid developments in the US and technical benefits of extending the grid. In addition, collaboration between US and Canada is suggested by the Canadian government in their stimulus package.

[20] Exhibit A-12, Pages 6 to 7
[21] Exhibit A-12, Page 7

4.0 Integrated Approach:

We believe that this Transmission Inquiry should be developed as an integrated process, one in which Generation, Demand and Transmission are considered in an integrated approach. We understand that the issues need to be split up into the separate areas in order to divide the issues into more manageable portions: "Assessment of Generation", "Assessment of Demand" and "Assessment of Transmission". However, in order to adequately address issues in all three areas in an integrated fashion, we suggest a new section of the scope be added and called "Integrated Approach".

A few examples have already been presented in this comment document, which would be appropriate to add to this new section. For example, we suggest that "Electric Vehicles" and "Vancouver Island" be added to this new section.

BRITISH COLUMBIA'S CLEAN OR RENEWABLE ELECTRICITY DEFINITIONS

Electricity generated in British Columbia may be reported as Clean or Renewable Electricity if:

1. The facility is in compliance with all applicable Federal and Provincial environmental regulations;

AND

2. The facility satisfies one of the following requirements:

a. The electricity is generated in a facility that uses a Clean or Renewable Electricity Resource or Technology as defined in this document.

b. The electricity is generated in a facility that fulfills one of the following requirements:

- It can be demonstrated that the facility meets the certification criteria for "electricity -- renewable low-impact" as defined by Environment Canada's Environmental Choice™ Program; or

- The facility maintains Environmental Choice™ Program certification.

c. Electricity is generated using a process, resource, or technology that is not recognized as Clean or Renewable in this document, but receives recognition from the Minister of Energy, Mines and Petroleum Resources as Clean or Renewable Electricity.

BRITISH COLUMBIA'S CLEAN OR RENEWABLE ELECTRICITY RESOURCES

Resources and technological applications that may qualify as a source for Clean or Renewable Electricity production are listed below:

BIOGAS ENERGY - means electricity generated from a system that captures biogas for combustion or conversion to electricity. Biogas means the gaseous products (primarily methane and carbon dioxide) produced from organic waste material. Facilities producing biogas include landfill sites, sewage treatment plants, and anaerobic digestion organic waste processing facilities.

BIOMASS ENERGY - means electricity generated from the combustion or gasification of organic materials. Biomass includes, but is not limited to:

- Clean wood biomass, meaning
  - wood residue within the meaning of the *Forest Act*,
  - wood debris from logging, construction, or demolition operations,
  - organic residues from pulp and paper production processes, and
  - timber, within the meaning of the *Forest Act* infested by the mountain pine beetle;
- Liquid fuels derived from biomass including bio-oil, ethanol, methanol, and bio-diesel;
- Dedicated energy crops; and
- Clean organically sourced material separated from municipal solid waste (MSW) and processed to serve as a combustion fuel.

Clean biomass does not include organic material that has been treated with inorganic substances such as paints, coal-tar creosote, pentachlorophenol or chromated copper arsenate, to change, protect, or supplement the physical properties of the materials.

If a facility co-fires fuels, or uses a mix of fuels that includes fossil fuels, only the proportion of the total electric output that can be attributed to the use of a clean or renewable fuel source qualifies as clean or renewable electricity. The proportion of the total electric output that qualifies as clean or renewable electricity must be calculated based on the proportion that clean or renewable energy constitutes of the total energy input used by the renewable energy system to generate electricity, or if practicable, separate metering.

ENERGY RECOVERY GENERATION (ERG) - means electricity produced from the recovery of waste energy from an industrial process that would otherwise have been vented or emitted into the atmosphere. ERG represents a net environmental improvement relative to existing energy production because it uses the waste of other processes to generate electricity. Therefore, all output from an ERG facility is considered Clean or Renewable Electricity.

GEOTHERMAL ENERGY - means electricity produced using the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well. This does not include hydrocarbons or water that has a temperature less than 80°C at the point where it reaches the surface.

HYDROCARBON ENERGY - means electricity produced from a facility combusting or converting fossil fuel using a closed-loop process whereby all greenhouse gas emissions from the operation of the facility are either deemed to be zero, negligible, or subject to long-term sequestration from the immediate receiving environment. Such a system requires approval of the Minister of Energy, Mines and Petroleum Resources for classification as Clean or Renewable Electricity.

HYDRO ENERGY - means electricity generated from a system or technology that converts either the potential or kinetic energy of water.

HYDROGEN - usually recognized as an energy carrier, hydrogen can also be used as a primary fuel source for internal combustion engines. Hydrogen produced from either a clean or renewable resource, or captured as a waste by-product of an industrial process, and then converted into electricity, is considered Clean or Renewable.

MUNICIPAL SOLID WASTE (MSW) - incineration of MSW to produce energy has both positive and negative environmental impacts. The release of carbon dioxide and other emissions is a negative impact, but reducing the amount of materials in landfills has benefits. Therefore, the combustion of MSW for electricity generation may be considered Clean or Renewable Electricity. A MSW incineration system requires approval of the Minister of Energy, Mines and Petroleum Resources for classification as Clean or Renewable Electricity.

MSW can also be converted to synthetic gas, which in turn is used to generate electricity. The electricity produced using such a process may be considered Clean or Renewable Electricity. A MSW-synthetic gas-generation system requires the approval of the Minister of Energy, Mines and Petroleum Resources for classification as Clean or Renewable Electricity.

SOLAR ENERGY - means electricity generated by converting the radiant light or heat energy of the sun through the use of photovoltaic and concentrating solar thermal technologies.

TIDAL ENERGY - means electricity produced by harnessing the natural rise and fall of the tides in the ocean.

WAVE ENERGY - means electricity produced by harnessing the natural rise and fall of waves in the ocean.

WIND ENERGY - means electricity produced from a system of airfoils or blades that spin a drive shaft to capture the kinetic energy of the wind.

OTHER POTENTIAL CLEAN OR RENEWABLE ELECTRICITY SOURCES - can include a project where the proponent or electricity distributor can demonstrate to the satisfaction of the Minister of Energy, Mines and Petroleum Resources that a project or application of technology otherwise excluded by this guideline, or not qualifying for certification under the Environmental Choice™ Program, should be recognized as producing Clean or Renewable Electricity.

Section 5
BC Transmission Inquiry

Comments on Resource Options to BC Hydro

by: ESVI, OEIA, ITO and ROMS BC

By: Ludo Bertsch, Horizon Technologies Inc.
[redacted]
Date: Aug 14, 2009
For: ESVI, OEIA, ITO and ROMS BC

On July 23, 2009, BC Hydro held a Resource Options workshop for the Long Term Electricity Transmission Inquiry. Participants were given the opportunity to provide written comments by August 14, 2009 for BC Hydro's consideration in its September 18 filings.

The following document contains the written comments on behalf of Energy Solutions for Vancouver Island Society (ESVI), Okanagan Environmental Industry Alliance (OEIA), IslandTransformations.Org (ITO) and Rental Owners and Managers Society of BC (ROMS BC).

Yours truly,
Ludo Bertsch, P. Eng
Horizon Technologies Inc.
bcuc@horizontec.com
[redacted]

Representing: ESVI, OEIA, ITO & ROMS BC

1.0 Scenario evidence

We also hereby submit the attached ESVI, OEIA, ITO & ROMS BC to BCTC "Comments on Scenarios" for Transmission Inquiry[1] for BC Hydro to consider.

2.0 Solar:

2.1 Solar in US and BC

2.1.1 Solar - US and BC Solar Radiation

There is a tendency for one to consider that the hot Arizona desert has plenty of solar potential for solar renewable energy, and to assume that BC would have significantly less. This reaction is understandable with maps such as those shown below from the National Renewable Energy Laboratory[2,3]:

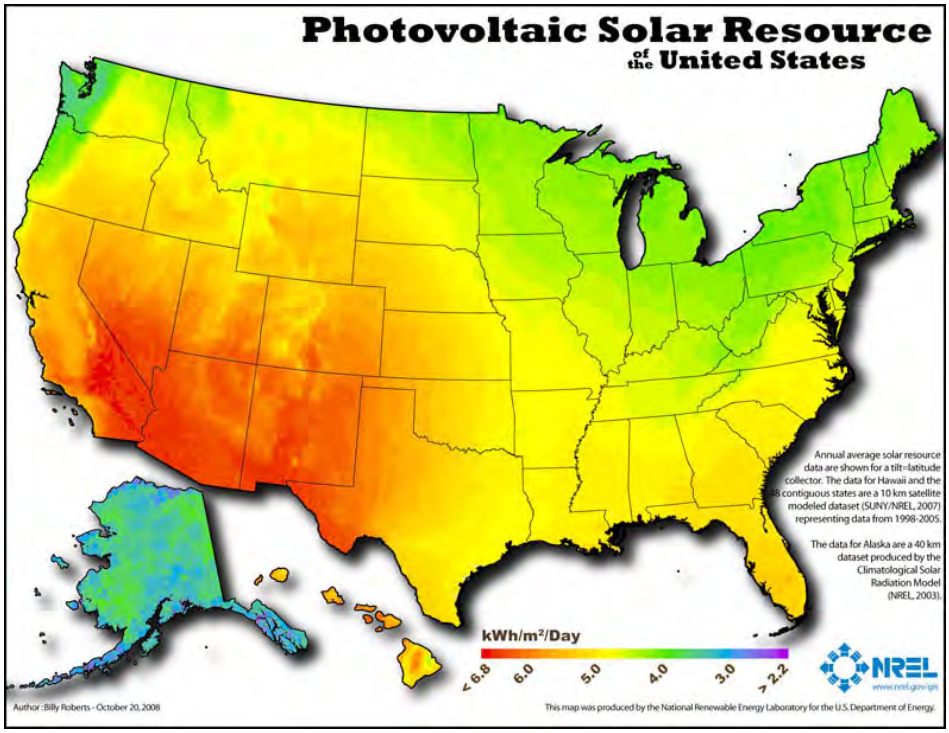

Figure 1 *– Solar insolation shaded map of US*

[1] Accompanied ESVI, OEIA, ITO & ROMS BC "Comments on Scenarios to BCTC" for Transmission Inquiry, Aug 12, 2009

[2] Appendix A, (Figure 1), National Renewable Energy Laboratory, Solar insolation shaded annual map of US

[3] Appendix B, (Figure 2), National Renewable Energy Laboratory, Solar insolation lumped annual map of US

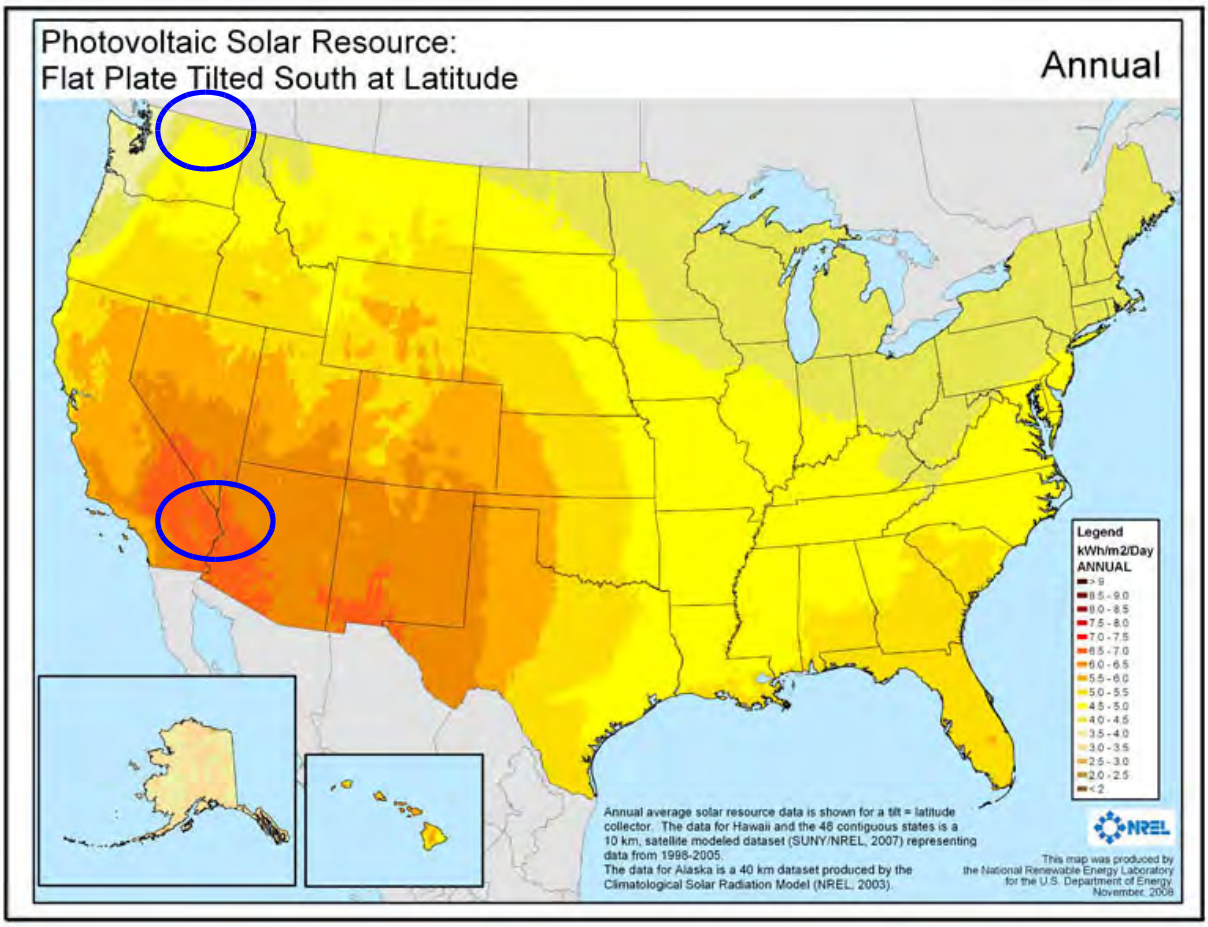

Figure 2 *– Solar insolation lumped map of US*

The maps show the annual levels of solar radiation (called, insolation) for areas through the United States.

The deserts of Arizona and Nevada are well known for their focus on significant solar projects. As seen in Figure 2 above, the areas around Arizona and Nevada show high levels of solar insolation with red shading, and northern Washington (bordering on BC) with lower levels with light brown/yellow shading. This seems to support the theory of a significant lack of solar potential in BC.

To gauge the actual difference between the two areas over the year, one approach would be to compare the actual solar insolation values for Phoenix, Arizona[4] and Kelowna, BC[5]. The overall solar radiation based on an average for the year[6], for Phoenix is 6.5 kWh/m^2 while Kelowna is 4.1 kWh/m^2 –

[4] Appendix C, National Renewable Energy Laboratory, Renewable Resource Data Center, Phoenix Solar Radiation tables

[5] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna

[6] assuming the solar panels are tilted south at an angle equal to the latitude

Kelowna has 63%[7] annual solar radiation as Phoenix. Even this difference is not as significant as the maps tend to indicate.

These values are calculated for a fixed angle solar panel tilted south at an angle equal to the latitude. By adjusting the angle, one can improve the performance over the year, or season. Typical adjustments include +15% and –15% from the latitude angle, horizontal, vertical and tracking (a mechanism to adjust the angle to always face directly to the sun).

If one were to optimize during the year without tracking (choosing the best between latitude, latitude -15%, latitude +15%, horizontal, vertical) the value for Kelowna increases slightly to 4.2 kWh/m^2 by using latitude -15% tilt, while Phoenix's remains at 6.5 kWh/m^2 at latitude tilt. This results in Kelowna being at a slightly improved value of 65%[8] solar insolation of Phoenix.

If one were to consider tracking systems, Kelowna's solar insolation is 5.9 kWh/m^2 while Phoenix's value is 8.9 kWh/m^2 . This results in a slight improvement to 66%[9].

Values in kWh/m^2 unless otherwise noted	**Kelowna**	**Phoenix**	**Kelowna/ Phoenix**
Annual – latitude tilt	4.1	6.5	**63%**
Annual – optimize tilt	4.2	6.5	**65%**
Annual – tracking	5.9	8.9	**66%**

Table 1 *– Annual Average Daily Solar Insolation*

Victoria has a similar annual solar insolation of 4.0 kWh/m^2 [10] compared to Kelowna's value of 4.1 kWh/m^2 [11]. The first map in Appendix F[12] of solar insolation in south BC (and reproduced below) shows that the annual solar radiation levels throughout southern BC are similar, although there are noticeably higher levels in the southern Interior regions.

[7] 4.1/6.5 = 63%
[8] 4.2/6.5 = 65%
[9] 5.9/8.9 = 66%
[10] Appendix E, National Resources Canada, Photovoltaic Potential and Solar Resources for Victoria, Annual Average at latitude tilt
[11] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna, Annual Average at latitude tilt
[12] Appendix F, National Resources Canada, PV Potential and Insolation, Annual South BC, Page 1

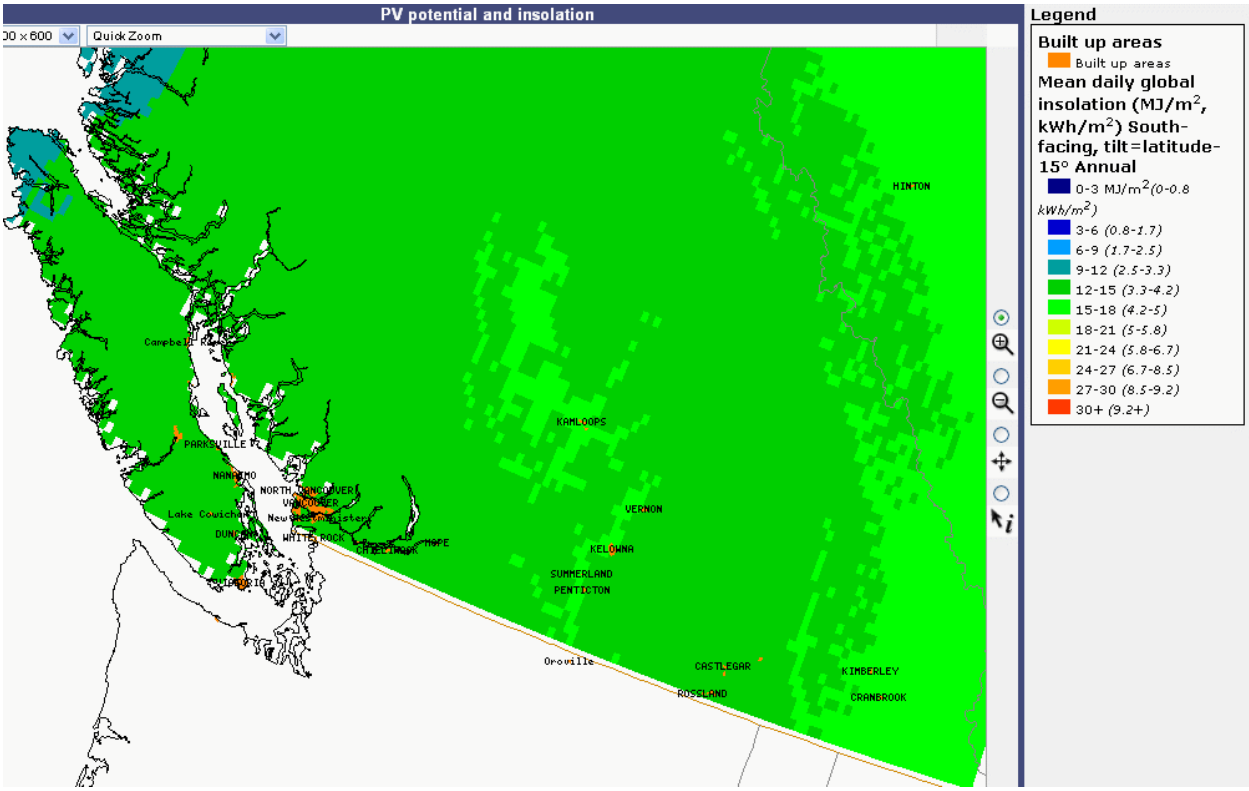

Figure 3 *– Annual South BC Solar Insolation*

The calculations and above maps are based on an annual basis.

The maps below (and the rest of the maps in Appendix F - pages 2 to 13), show the average solar insolation based on a monthly basis.

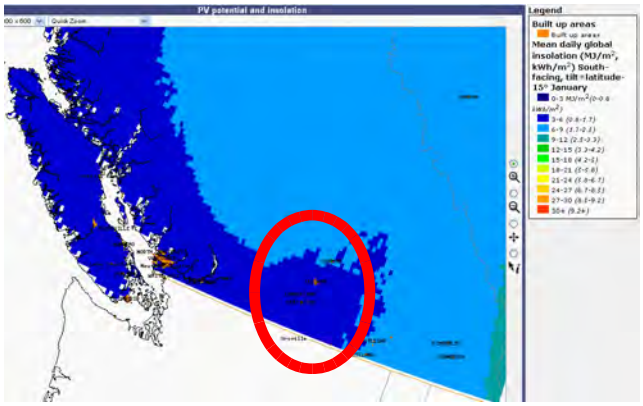

Figure 4 *– January South BC Solar Insolation*

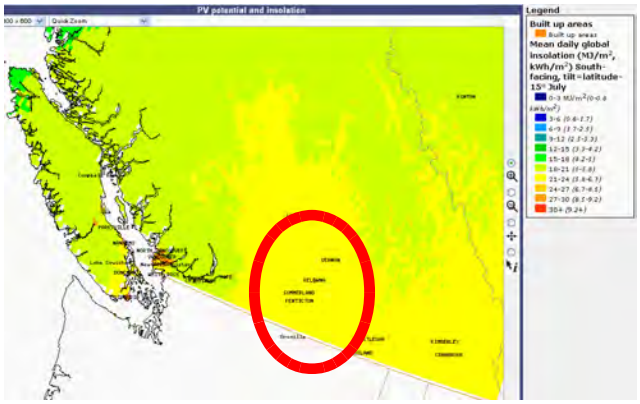

Figure 5 *July South BC Solar Insolation*

Looking at the maps above for January[13], the Southern Interior's (inside red marked zone) solar radiation levels are lower (darker blue) than areas to the

[13] Appendix F, National Resources Canada, PV Potential and Insolation, January - South BC, Page 2

east and north (lighter blue). On the other hand, the map for July[14] shows that the solar insolation levels are higher (yellow) in the Southern Interior than other areas in light green.

It is noted that the workshop presentation by BC Hydro on July 23, 2009 only provided an annual solar insolation map of BC[15]. We suggest that monthly solar insolation maps such as those as provided in Appendix F of this document should also be considered in evaluating the appropriateness and potential of the resource – see the following sections of this document (sections 2.1.2 and 2.1.3).

2.1.2 Solar - FortisBC 2009 Resource Plan

In the BCUC Scoping Document it is stated: "*FortisBC noted the importance of considering its recently filed 2009 Resource Plan and the* ***Panel concurs that FortisBC's 2009 Resource Plan will provide valuable information to the Inquiry****.*"[16]

From the FortisBC Resource Plan: "*FortisBC is a capacity constrained utility.*"[17]

"*Specific to the 'Canada' sub-region summer capacity is expected to be sufficient until 2015, at which time current and currently planned resources will no longer provide sufficient capacity. The shortfall at that time is projected to be about 336 MW.*"[18] The summer deficiency is shown in a graphical form in the Resource Plan[19].

As noted in FortisBC's Resource Plan, the WECC *2008 Power Supply Assessment* notes in reference to Capacity Constraints: "*'Surplus generation in the Pacific Northwest zone was often stranded due to transmission limitations... However, neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses, both for Northwest sub-region's load and for potential export to other sub-regions of the West, may be unrealistically high.*"[20]

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[14] Appendix F, National Resources Canada, PV Potential and Insolation, July - South BC, Page 8
[15] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "Solar Potential", Page 27
[16] Exhibit A-18, Appendix A, Page 6 of 13
[17] FortisBC 2009 Resource Plan, May 29, 2009, Page 3, Line 21
[18] FortisBC 2009 Resource Plan, May 29, 2009, Page 4, Lines 10 to 12
[19] FortisBC 2009 Resource Plan, May 29, 2009, Page 48, Graph 1
[20] FortisBC 2009 Resource Plan, May 29, 2009, Page 49, Lines 9 to 13

FortisBC continues: "*FortisBC acknowledges that the market environment has changed substantially since the publication of the 2008 WECC PSA . Specifically, FortisBC understands that the short term forecast gap between regional loads and resources has been reduced. The May 2009 forecast of the Energy Information Administration (US Department of Energy) notes that although energy consumption is expected to be reduced in 2009, it is expected to return to a more normal growth rate in 2010. Given that the planning period of this 2009 Resource Plan is twenty years, and that it contemplates new resources that require extended implementation timeframes, FortisBC believes it is still prudent to continue to use WECC's long term assessment of the wholesale electricity market.*"[21]

In summary: "*On this basis, over the longer term, an overall tight supply is forecast in the WECC region.*"[22]

There are indicators of challenges for the summer load for FortisBC: "*FortisBC's system set a new summer peak requirement record of 569 MW in July 2007.*"[23]

Within the "*Market Shortages*"[24] section of the resource plan, one event was highlighted: *"For example, in July 2006 FortisBC experienced load 20% higher than the previous year's average July load, and 8% higher than on the previous year's hottest summer day, resulting in the need to make an unanticipated wholesale market purchase of 1,680 MWh at an average price of $225 per MW.*"[25]

In summary of the *"Market Shortages*" section, FortisBC notes: "*Consequently, FortisBC concludes that it is no longer reasonable to expect supply from the wholesale electricity market to be available, at a stable price, and on a reliable basis.*"[26]

Within the "*Price Risk*"[27] section FortisBC explains about the volatile market: "*This volatility potential is exacerbated by . . . FortisBC's summer peak is growing, and has exceeded existing capacity. During the summer months, markets in the southern states (California for example) are also peaking, and market costs are typically driven up at this time.*"[28]

"*The potential combined impact is that at some point the Company will be*

[21] FortisBC 2009 Resource Plan, May 29, 2009, Page 49, Lines 14 to 21
[22] FortisBC 2009 Resource Plan, May 29, 2009, Page 49, Lines 21 to 22
[23] FortisBC 2009 Resource Plan, May 29, 2009, Page 28, Line 9 to 10
[24] FortisBC 2009 Resource Plan, May 29, 2009, Page 63, Section 4.1.1.2
[25] FortisBC 2009 Resource Plan, May 29, 2009, Page 63, Line 9 to Page 64, Line 2
[26] FortisBC 2009 Resource Plan, May 29, 2009, Page 64, Lines 15 to 16
[27] FortisBC 2009 Resource Plan, May 29, 2009, Page 69, Section 4.4.1.2
[28] FortisBC 2009 Resource Plan, May 29, 2009, Page 69, Lines 21 to 27

paying well above FortisBC's current cost structure."[29]

In forecasting the demand, FortisBC notes: "*The summer season peak is the peak experienced in either July or August.*"[30]

The increasing summer gap is illustrated in a graphical form in the Resource Plan[31] and is shown below. The FortisBC demand for years 2009 to 2028 are shown against the available resources:

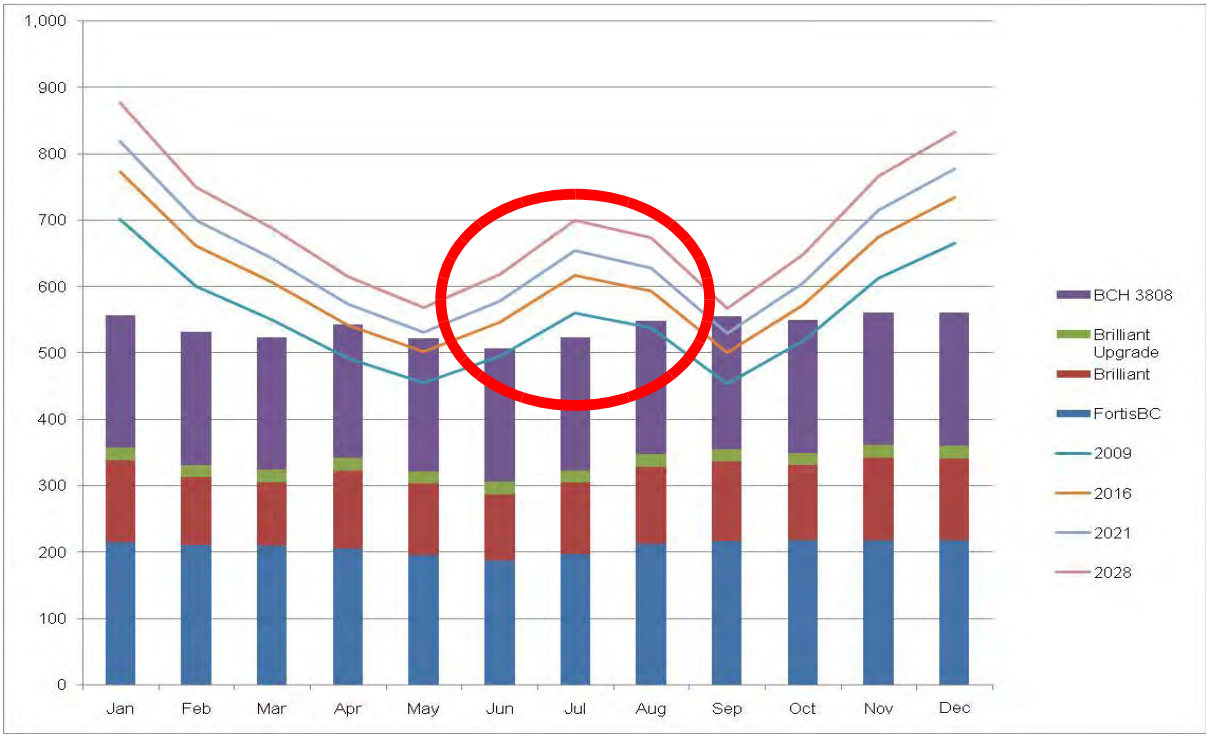

Figure 6 *- FortisBC Monthly Peak Capacity: Current & Forecast*

From the above graph, it can be easily seen that up to 2009 the summer shortage as marked by the red oval - June to August - for FortisBC has not been significant; e.g. the 2009 demand can essentially be supplied by the available resources. However, that situation changes dramatically by 2028 where the demand outstrips the resources for all summer months.

[29] FortisBC 2009 Resource Plan, May 29, 2009, Page 70, Lines 1 to 2
[30] FortisBC 2009 Resource Plan, May 29, 2009, Page 76, Lines 17
[31] FortisBC 2009 Resource Plan, May 29, 2009, Page 81, Figure 5.3.2

2.1.3 Solar - FortisBC/Southern Interior Summer Analysis

In the BCUC Scoping Document, the Inquiry Panel notes: "*ESVI also suggested that 'the regional aspect for wind be expanded to include the regional considerations for solar' . The Panel understands the examples in the Staff Paper to be illustrative and that the cost estimates for various generation resources (especially developing technologies, including both wind and solar) will have regional considerations.* ***Thus the Panel agrees with ESVI that regional considerations for solar are within scope."***[32]

In looking at the summer challenges in the southern interior, a possible resource is solar (both thermal and photovoltaic). The advantages of a solar resource is that the main driving force behind the increased demand on a day by day basis is directly related to the resource during the summer season. It is a type of feedback loop, where the increased summer demand is typically caused by an increase in air conditioning requirements, which is accompanied by an increase in the solar resource.

In addition, should even sunnier weather be experienced by climate change impacts (as discussed in ESVI, OEIA, ITO & ROMS BC Scenario Comment submission[33]), this will also be typically accompanied by an increase in the availability of the solar resource.

The solar insolation for Kelowna is an average daily of 6.17 kWh/m^2 [34], while the average daily for Phoenix is at 7.7 kWh/m^2 [35].for FortisBC's predicted summer shortfall - the months of June, July and August[36]. This makes Kelowna a value of 80%[37] of Arizona's solar insolation for the summer.

The performance for Kelowna increases further by looking at on the months in which the peak summer demand occurs, July and August[38]. Kelowna's daily average is 6.15 kWh/m^2 [39] while Phoenix's daily average is 7.4 kWh/m^2 [40]. This means, during the months in FortisBC's summer peak occurs, Kelowna's

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[32] Exhibit A-18, Appendix A, Page 5 of 13
[33] Accompanied ESVI, OEIA, ITO & ROMS BC "Comments on Scenarios to BCTC" for Transmission Inquiry, Aug 12, 2009, Section 4.1, "*Climate Change Impacts*"
[34] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna; using values maximized for summer: (6.3+6.6+5.6)/3=6.17 for horizontal (not considering tracking)
[35] Appendix C, National Renewable Energy Laboratory, Phoenix Solar Radiation tables; using values maximized for summer: (8.4+7.6+7.1)/3=7.7 for horizontal (no considering tracking)
[36] See Section 2.1.2 "*Solar – FortisBC 2009 Resource Plan*" within this document
[37] 6.17/7.7 = 80% (this is for horizontal). The value for latitude–15% (next maximum value, not considering tracking) is the same: (6.0+6.3+6.0)/(8.1+7.5+7.3) = 80%.
[38] FortisBC 2009 Resource Plan, May 29, 2009, Page 76, Line 17
[39] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna; using values maximized for July and August: (6.3+6.0)/2=6.15 for latitude–15% (not considering tracking)
[40] Appendix C, National Renewable Energy Laboratory, Phoenix Solar Radiation tables; using values maximized for July and August: (7.5 + 7.3)/2=7.4 for latitude-15% (not considering tracking)

solar insolation levels are at 83%[41] of those in Phoenix, Arizona.

With consideration to tracking, Kelowna rises to 9.03 kWh/m^2 [42] during the summer, and 9.05 kWh/m^2 [43] in July and August, while Phoenix rises to 10.5 kWh/m^2 during the summer and 9.95 kWh/m^2 in July and August. Correspondingly, Kelowna's solar insolation with tracking is at 91% of Phoenix, Arizona.

Values in kWh/m^2 unless otherwise noted	**Kelowna**	**Phoenix**	**Kelowna/ Phoenix**
Summer – optimize tilt	6.17	7.7	**80%**
July/Aug – optimize tilt	6.15	7.4	**83%**
Summer – tracking	9.03	10.5	**86%**
July/Aug – tracking	9.05	9.95	**91%**

Table 2 *– Seasonal Average Daily Solar Insolation*

2.2 Solar – Conclusion

In conclusion, we suggest the evidence provided within this document[44] shows that calculations and discussions for Solar technology as a resource for the prime areas in the US (e.g. Arizona) are nearly equally applicable for the southern Interior of BC for the summer peak times and should not be discounted out-of-hand.

Further discussion and technology background for Solar Technology including future price estimates are described in Section 6 and its subsections of the ESVI, OEIA, ITO & ROMS BC "*Comments of Scenarios*" submission[45] and we suggest BC Hydro should use that information for its Resource Options work and analysis. Similarly other sections of that submission, namely regarding Feed-In Tariffs and Distributed Generation[46] are also relevant and again we suggest BC Hydro should use that information for its Resource Options work and analysis.

It is noted that Solar is not listed in the Summary within the Cluster section[47] and

[41] 6.15/7.4 = 83% (this is for latitude-15%)
[42] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna; using values for the summer: (9.0+9.5+8.6)/3=9.03
[43] Appendix D, National Resources Canada, Photovoltaic Potential and Solar Resources for Kelowna; using values for July and August: (9.5+8.6)/2=9.05
[44] Section 2 "*Solar*" and its subsections of this document,
[45] Accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry, Aug 12, 2009, Section 6 "*Solar*" and its subsections
[46] such as Accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry, Aug 12, 2009, Section 5 "*Feed-In Tariffs and "Distributed Generation*" and its subsections
[47] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Transmission Region Summary After Exclusion (Draft)*", Page 40 & 41

suggest that it be included. If no specific projects can be identified, it is suggested that estimates be included, along with assumptions.

3.0 Ocean:

3.1 Ocean - Discussion

The ESVI, OEIA, ITO & ROMS BC "*Comments of Scenarios*" submission submitted to BCTC on August 12 contained a section called "Ocean"[48]. That section described the Ocean Technology, referenced numerous tables and other information and we suggest the entire section (including all referenced footnotes) should be used by BC Hydro in their Resource Options work and analysis.

For convenience, we have attached an Appendix G, which is a compilation of CHC's report material referenced in the "Comments of Scenario submission"[49]. It appears that pages 31 and 95 have been used in the workshop presentation in slide 28[50].

There are also additional relevant reference material throughout in the "*Inventory of Canada's Marine Renewable Energy Resources*" report produced by Canadian Hydraulics Centre (CHC) of Natural Resources Canada - find attached Appendix H, which is a compilation of those pages[51].

A feasibility study, called "*Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast*"[52] written by Bob Davidson was done for the British Columbia Ministry of Energy, Mines and Petroleum Resources. In conclusion it states:

> "*At this point in time, tidal power technology is not far enough advanced for it to be feasible for installation at Stuart Island to replace the existing diesel generators. However, it won't be long until commercial size devices have been built and tested. There are a handful of Canadian manufacturers of tidal turbines that have working small scale devices that will soon be scaled up for use in commercial applications. The world leaders in the field are in the UK, but Canadian developers are not far behind.*"[53]

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[48] Accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry, Aug 12, 2009, Section 7 and subsections, "*Ocean*"

[49] Appendix G, Canada Hydraulics Centre of Natural Resources Canada: pages that were referenced in ESVI, OEIA, ITO & ROMS BC "Comments of Scenario", August 12, 2009

[50] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Wave & Tidal energy Potential*", Page 28

[51] Appendix H, Canada Hydraulics Centre of Natural Resources Canada: relevant extra pages for this Resource Options

[52] Appendix I, British Columbia Ministry of Energy, Mines and Petroleum Resources, "*Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast"*

[53] Appendix I, British Columbia Ministry of Energy, Mines and Petroleum Resources, "*Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast",* Page 80

One of drawings in the report show the potential tidal resource sites along the mid Vancouver Island coast[54] - it is reproduced below.

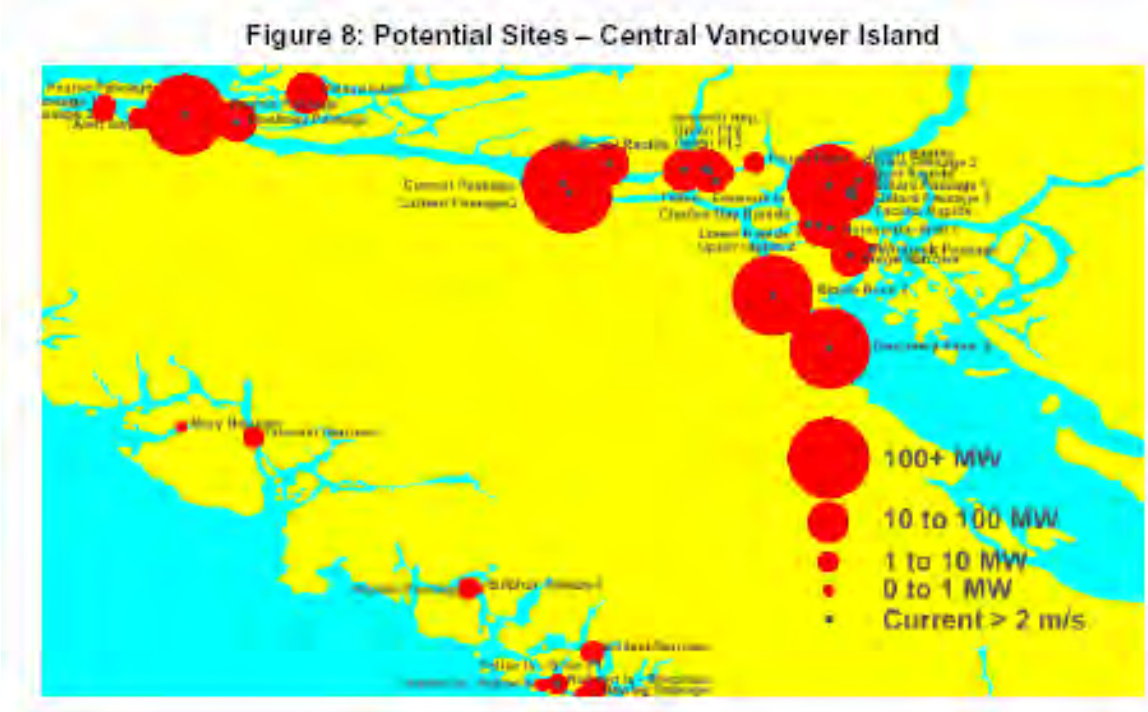

Figure 7 *- Tidal Resources along the Mid Vancouver Island coast*[55]

Another report examines the tidal current assessment potential in the Johnstone Strait region[56] and is included in Appendix J of this document.

> "*The maximum extractable power in northwestern Johnstone Strait is found to be 1335 MW, which agrees well with the theoretical estimate of 1320 MW. In Discovery Passage and Cordero Channel, the maximum extractable power is modelled to be 401 and 277 MW, respectively, due to the flow being partly diverted into the other channel.*"[57]

A table is produced showing the power estimates for various channels[58].

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[54] Appendix I, British Columbia Ministry of Energy, Mines and Petroleum Resources, "*Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast",* Page 45

[55] Appendix I, British Columbia Ministry of Energy, Mines and Petroleum Resources, "*Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast",* Page 45

[56] Appendix J, G Sutherland, M.Foreman, and C Garrett, from UVic and Institute of Ocean Sciences, "*Tidal current energy assessment for Johnstone Strait, Vancouver Island"*

[57] Appendix J, G Sutherland, M.Foreman, and C Garrett, from UVic and Institute of Ocean Sciences, "*Tidal current energy assessment for Johnstone Strait, Vancouver Island"*, Page 147

[58] Appendix J, G Sutherland, M.Foreman, and C Garrett, from UVic and Institute of Ocean Sciences, "*Tidal current energy assessment for Johnstone Strait, Vancouver Island"*, Page 154

3.2 Ocean – Conclusion

We suggest that BC Hydro check that the workshop slides #28 & #29[59] has incorporated the reference materials presented in the two ESVI, OEIA, ITO & ROMS BC documents[60]. It is also suggested that BC Hydro take these reference materials into account in its further analysis.

4.0 <u>Distributed Generation:</u>

4.1 Distributed Generation - Discussion

The ESVI, OEIA, ITO & ROMS BC "*Comments of Scenarios*" submission submitted to BCTC on August 12 contained a section called "*Feed-In Tariffs and Distributed Generation*"[61]. That section discussed relevant topics, studies and reports regarding Feed-In Tariffs and Distributed Generation and we suggest the entire section (including all referenced footnotes) should be used by BC Hydro in their Resource Options work and analysis.

Amory Lovins, of Rocky Mountain Institute, and others wrote a best seller book called "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*"[62].

> "*It finds that properly considering the economic benefits of "distributed" (decentralized) electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation (especially of the grid), and service quality, and by avoiding societal costs.*"[63]
>
> The book describes 207 benefits of distributed resources[64].

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[59] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Wave & Tidal energy Potential*", Slides 28 & 29
[60] This document and the accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry document
[61] Accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry, Aug 12, 2009, Section 5 and subsections, "*Feed-In Tariffs and Distributed Generation*"
[62] Appendix K, Amory Lovins, Rocky Mountain Institute, Excerpts from "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size", 2003*
[63] Appendix K, Amory Lovins, Rocky Mountain Institute, Excerpts from "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size", 2003,* Executive Summary, Page 1
[64] Appendix K, Amory Lovins, Rocky Mountain Institute, Excerpts from "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size", 2003, "207 Benefits of Distributed Resources"*

The Canadian Renewable Energy Alliance estimates in its Canadian Distributed Generation report that: "*as of 2005, fully 25% of new electricity generation installed came from distributed resources, compared to only 13% in 2002*"[65].

> "*Historically, energy policy in Canada has emphasized large centralized electricity generation and long-distance, high-voltage transmission from centralized sources such as large-scale hydro, coal, natural gas and nuclear power plants. Canada's aging centralized energy infrastructure is becoming more problematic as demand for clean, reliable and affordable electricity generation grows. North America's centralized grid system, stressed to its limits, has become vulnerable, increasingly brittle, and inefficient. Over-reliance on large, polluting and expensive generation and transmission is no longer an option that Canadians will endorse. More and more frequently, centralized generation is being supplemented or replaced by distributed generation (DG), a new way of thinking about electricity generation, transmission and distribution. The market share of renewable DG continues to grow, and shows no signs of slowing.*"[66]

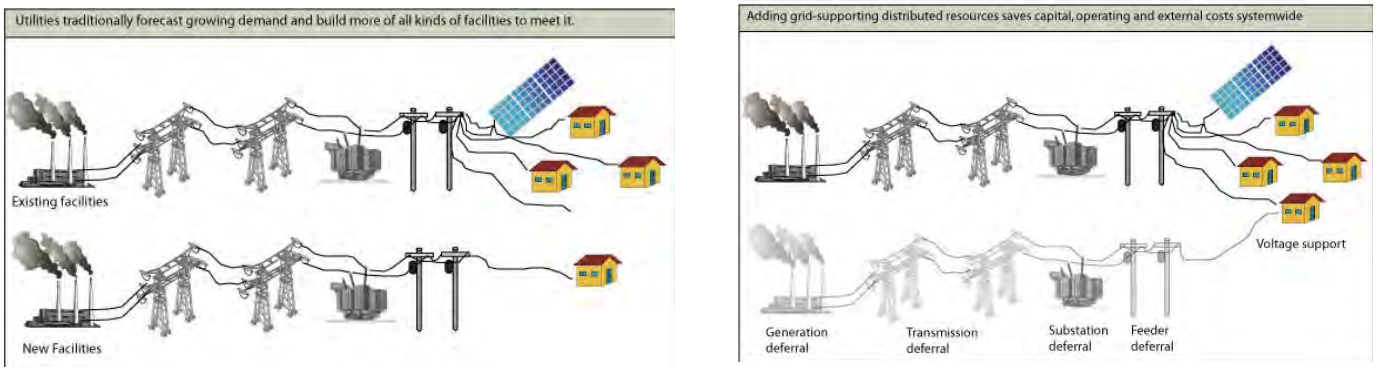

Figure 8 *– From a traditional utility to Distributed Resources*[67]

It is noted that while the other resource options have "*potential*" maps[68] for BC, Distributed Generation did not and we suggest that such maps be included – in addition to the text description was included[69]. If sufficient information for such a map is not possible, it is suggested that estimated generation should be used to develop the map, and we suggest the assumptions be included.

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[65] Appendix L, Canadian Renewable Energy Alliance, "*Distributed Generation in Canada -Maximizing the benefits of renewable resources*", 2006, Page 2
[66] Appendix L, Canadian Renewable Energy Alliance, "*Distributed Generation in Canada -Maximizing the benefits of renewable resources*", 2006, Page 2
[67] Appendix L, Canadian Renewable Energy Alliance, "*Distributed Generation in Canada -Maximizing the benefits of renewable resources*", 2006, Page 5 & 6
[68] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Transmission Region Summary After Exclusion (Draft)*", Slides 18 to 29
[69] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Distributed Generation*", Slide 30

It is also noted that Distributed Generation is not listed in the Summary within the Cluster section[70] of the workshop presentation and we suggest that Distributed Generation be included. If no specific projects can be identified, it is suggested that estimates be included, along with assumptions.

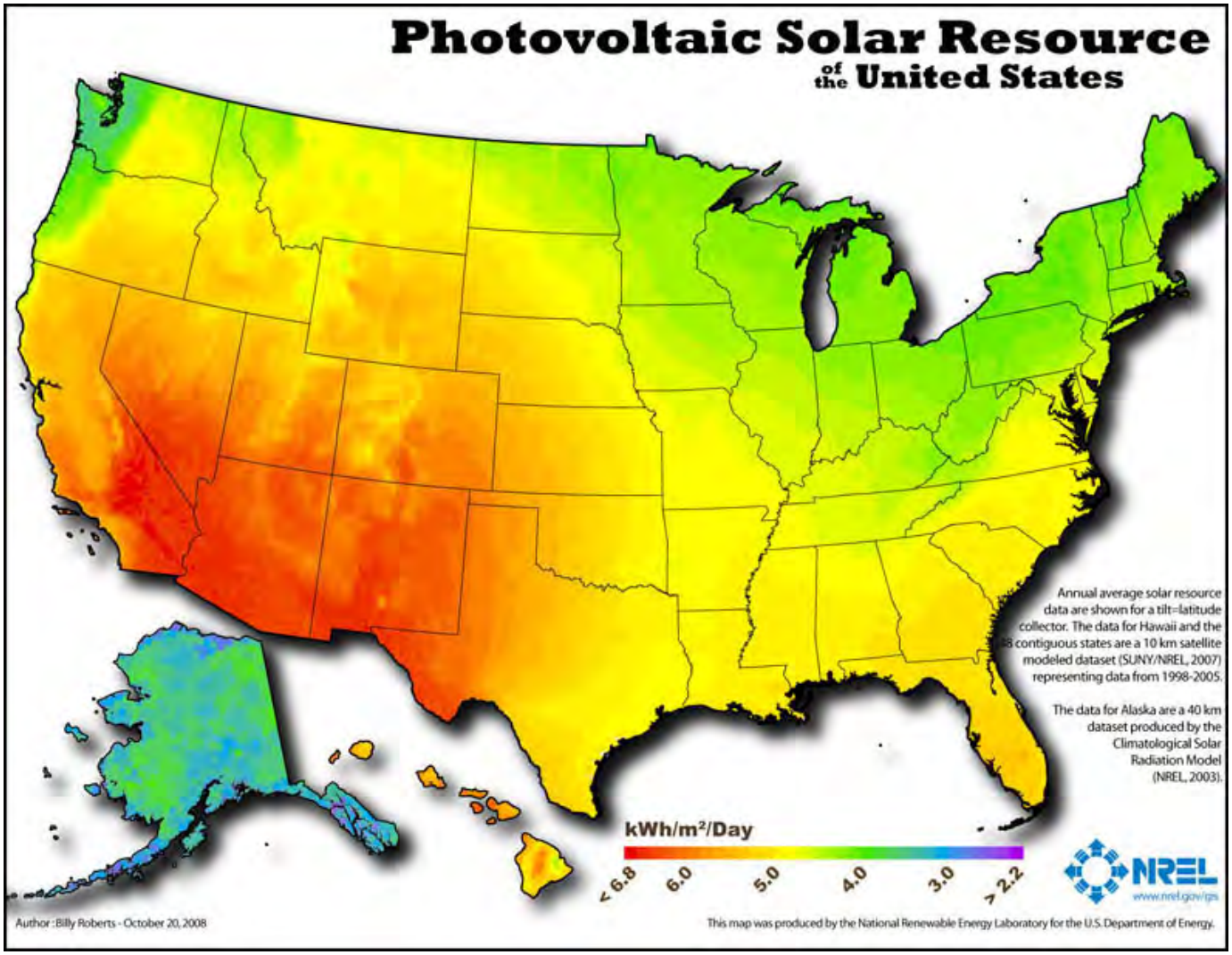
BC Hydro provides an estimate of 5100 GWh of potential due to Distributed Generation[71] – it is suggested that the assumptions and calculations used to calculate this number to be included; it is also suggested that this number be broken down to the regional level.

4.2 Distributed Generation – Conclusion

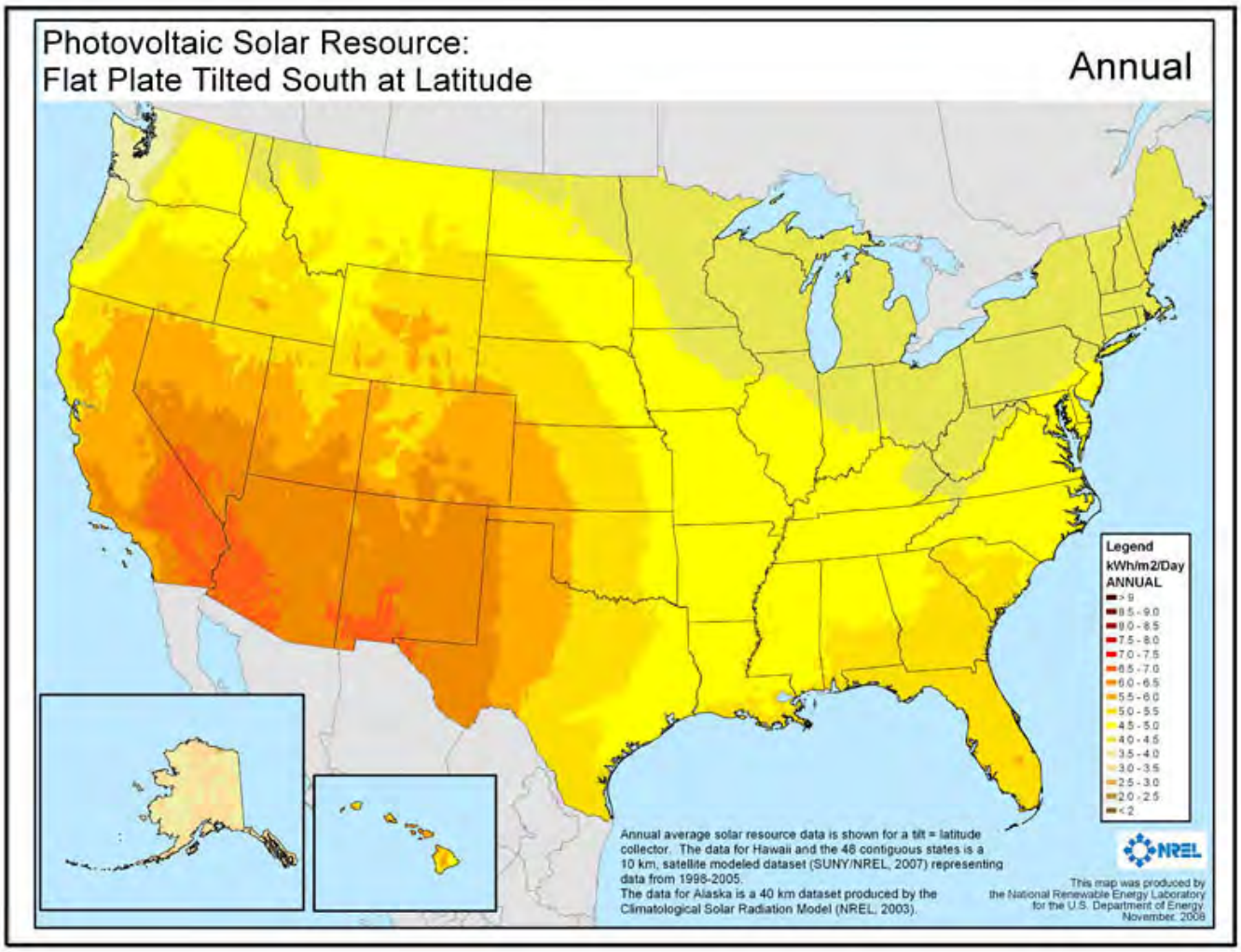
Based upon the direction of the industry and other information provided in the two ESVI, OEIA, ITO & ROMS BC documents[72] we suggest that BC Hydro fully develop the Distributed Generation resource as part of its Resource Options work, and consider appropriate pricing techniques to account for all the benefits of Distributed Generation.

[70] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Transmission Region Summary After Exclusion (Draft)*", Pages 40 & 41
[71] BC Hydro, Long Term Electricity Transmission Inquiry, Resource Options Workshop, "*Distributed Generation*", Page 30
[72] This document and the accompanied ESVI, OEIA, ITO & ROMS BC "*Comments on Scenarios to BCTC*" for Transmission Inquiry document

APPENDICES


Photovoltaic Solar Resource
of the United States
Annual average solar resource data are shown for a tilt=latitude collector. The data for Hawaii and the 48 contiguous states are a 10 km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2005.
The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).
kWh/m²/Day
< 6.8
6.0
5.0
4.0
3.0
> 2.2
NREL
www.nrel.gov/gis
Author : Billy Roberts - October 20, 2008
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.

Appendix A


Photovoltaic Solar Resource:
Flat Plate Tilted South at Latitude
Annual
Legend
kWh/m2/Day
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> 9
8.5 - 9.0
8.0 - 8.5
7.5 - 8.0
7.0 - 7.5
6.5 - 7.0
6.0 - 6.5
5.5 - 6.0
5.0 - 5.5
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3.0 - 3.5
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2.0 - 2.5
< 2
Annual average solar resource data is shown for a tilt = latitude collector. The data for Hawaii and the 48 contiguous states is a 10 km, satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2005.
The data for Alaska is a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).
NREL
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy November, 2008

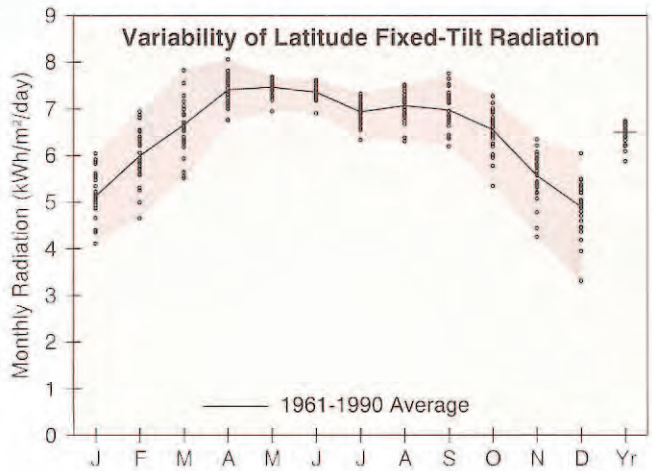
Appendix B

Phoenix, AZ

WBAN NO. 23183

LATITUDE: 33.43° N
LONGITUDE: 112.02° W
ELEVATION: 339 meters
MEAN PRESSURE: 974 millibars

STATION TYPE: Primary



Solar Radiation for Flat-Plate Collectors Facing South at a Fixed Tilt (kWh/m²/day), Uncertainty ±9%

Tilt (°)		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Year
0	Average	3.2	4.3	5.5	7.1	8.0	8.4	7.6	7.1	6.1	4.9	3.6	3.0	5.7
	Min/Max	2.8/3.7	3.5/4.8	4.7/6.4	6.4/7.8	7.5/8.3	7.8/8.7	6.9/8.1	6.3/7.5	5.4/6.7	4.2/5.3	3.0/4.0	2.2/3.5	5.3/5.9
Latitude -15	Average	4.4	5.4	6.4	7.5	8.0	8.1	7.5	7.3	6.8	6.0	4.9	4.2	6.4
	Min/Max	3.6/5.1	4.3/6.2	5.3/7.4	6.8/8.2	7.4/8.2	7.6/8.4	6.8/8.0	6.5/7.8	6.1/7.6	5.0/6.6	3.8/5.5	2.9/5.1	5.8/6.6
Latitude	Average	5.1	6.0	6.7	7.4	7.5	7.3	6.9	7.1	7.0	6.5	5.6	4.9	6.5
	Min/Max	4.1/6.0	4.7/6.9	5.5/7.8	6.8/8.1	6.9/7.7	6.9/7.6	6.3/7.3	6.3/7.5	6.2/7.8	5.3/7.3	4.3/6.3	3.3/6.0	5.9/6.7
Latitude +15	Average	5.5	6.2	6.6	6.9	6.6	6.3	6.0	6.4	6.7	6.7	5.9	5.3	6.3
	Min/Max	4.4/6.6	4.8/7.3	5.4/7.8	6.2/7.5	6.1/6.8	5.9/6.5	5.5/6.3	5.7/6.8	5.9/7.5	5.4/7.4	4.4/6.8	3.5/6.7	5.6/6.5
90	Average	4.9	5.0	4.5	3.7	2.7	2.3	2.4	3.1	4.2	5.1	5.1	4.8	4.0
	Min/Max	3.8/5.9	3.8/5.9	3.7/5.3	3.3/3.9	2.6/2.8	2.1/2.4	2.2/2.5	2.8/3.3	3.7/4.6	4.1/5.7	3.7/6.0	3.1/6.2	3.5/4.2

Solar Radiation for 1-Axis Tracking Flat-Plate Collectors with a North-South Axis (kWh/m²/day), Uncertainty ±9%

Axis Tilt (°)		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Year
0	Average	4.7	6.2	7.8	9.9	11.0	11.4	10.0	9.6	8.6	7.1	5.3	4.4	8.0
	Min/Max	3.8/5.6	4.6/7.3	6.2/9.5	8.9/11.4	9.9/11.8	10.3/12.2	8.8/11.1	8.0/10.5	7.4/9.9	5.6/8.1	4.0/6.2	2.9/5.5	7.1/8.4
Latitude -15	Average	5.6	7.1	8.5	10.3	11.1	11.3	10.0	9.8	9.2	8.0	6.3	5.3	8.5
	Min/Max	4.4/6.7	5.2/8.3	6.7/10.3	9.2/11.9	9.9/11.8	10.2/12.1	8.8/11.1	8.2/10.8	7.9/10.5	6.2/9.1	4.6/7.3	3.4/6.7	7.6/8.9
Latitude	Average	6.2	7.5	8.7	10.3	10.7	10.8	9.6	9.6	9.3	8.4	6.8	5.8	8.6
	Min/Max	4.8/7.4	5.5/8.9	6.8/10.6	9.1/11.8	9.6/11.5	9.8/11.6	8.4/10.7	8.1/10.6	8.0/10.7	6.5/9.5	4.9/8.0	3.8/7.4	7.6/9.0
Latitude +15	Average	6.5	7.7	8.6	9.9	10.1	10.1	9.0	9.2	9.1	8.5	7.1	6.2	8.5
	Min/Max	5.0/7.8	5.6/9.1	6.8/10.5	8.8/11.4	9.1/10.8	9.1/10.8	7.9/10.0	7.7/10.1	7.8/10.5	6.6/9.7	5.1/8.3	4.0/7.9	7.5/8.9

Solar Radiation for 2-Axis Tracking Flat-Plate Collectors (kWh/m²/day), Uncertainty ±9%

Tracker		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Year
2-Axis	Average	6.6	7.7	8.7	10.4	11.2	11.6	10.1	9.8	9.3	8.5	7.1	6.3	8.9
	Min/Max	5.1/7.9	5.6/9.1	6.9/10.6	9.2/11.9	10.1/12.0	10.5/12.4	8.9/11.3	8.3/10.9	8.0/10.7	6.6/9.7	5.1/8.4	4.0/8.1	7.9/9.4

Direct Beam Solar Radiation for Concentrating Collectors (kWh/m²/day), Uncertainty ±8%

Tracker		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Year
1-Axis, E-W Horiz Axis	Average	4.2	4.6	4.8	5.7	6.4	6.8	5.6	5.3	5.2	5.0	4.5	4.1	5.2
	Min/Max	3.0/5.4	3.0/5.9	3.4/6.3	4.8/7.1	5.2/7.1	6.0/7.5	4.5/6.7	4.4/6.3	4.1/6.3	3.5/6.0	2.6/5.8	2.5/5.8	4.5/5.6
1-Axis, N-S Horiz Axis	Average	3.4	4.6	5.8	7.6	8.5	8.9	7.2	7.0	6.5	5.4	4.0	3.2	6.0
	Min/Max	2.4/4.5	2.8/5.9	4.0/7.7	6.5/9.8	7.0/9.7	7.9/10.0	5.7/8.8	5.6/8.4	5.1/8.1	3.6/6.6	2.2/5.1	1.8/4.5	5.2/6.5
1-Axis, N-S Tilt=Latitude	Average	4.7	5.7	6.5	7.8	8.2	8.3	6.8	7.0	7.1	6.5	5.2	4.5	6.5
	Min/Max	3.3/6.1	3.6/7.3	4.5/8.6	6.6/10.1	6.7/9.4	7.3/9.3	5.4/8.3	5.6/8.4	5.5/8.7	4.4/7.8	3.0/6.7	2.6/6.3	5.6/7.1
2-Axis	Average	5.0	5.8	6.5	8.0	8.7	9.1	7.3	7.2	7.1	6.5	5.5	4.8	6.8
	Min/Max	3.5/6.5	3.7/7.5	4.5/8.6	6.7/10.3	7.1/9.9	8.0/10.1	5.8/9.0	5.7/8.6	5.5/8.7	4.4/7.9	3.1/7.1	2.8/6.8	5.8/7.4

Average Climatic Conditions

Element	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Year
Temperature (°C)	12.0	14.3	16.8	21.1	26.0	31.2	34.2	33.1	29.8	23.6	16.6	12.3	22.6
Daily Minimum Temp	5.1	7.1	9.3	12.9	17.7	22.7	27.2	26.2	22.7	16.0	9.4	5.4	15.2
Daily Maximum Temp	18.8	21.5	24.2	29.2	34.2	39.7	41.1	39.8	36.8	31.2	23.8	19.0	29.9
Record Minimum Temp	-8.3	-5.6	-3.9	0.0	4.4	10.0	16.1	15.6	8.3	1.1	-3.9	-5.6	-8.3
Record Maximum Temp	31.1	33.3	37.8	40.6	45.0	50.0	47.8	46.7	47.8	41.7	33.9	31.1	50.0
HDD, Base 18.3°C	201	126	101	42	4	0	0	0	0	9	74	192	750
CDD, Base 18.3°C	4	12	53	123	242	387	491	457	343	173	23	4	2312
Relative Humidity (%)	51	44	39	28	22	19	32	36	36	37	44	52	37
Wind Speed (m/s)	2.5	2.8	3.2	3.4	3.4	3.2	3.4	3.2	3.0	2.8	2.6	2.5	3.0

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Photovoltaic potential and solar resource maps of Canada

Photovoltaic (PV) potential (kWh/kW) and mean daily global insolation (MJ/m^2 and kWh/m^2) data are presented below for the selected municipality. Data is presented for each month and on a yearly basis for 6 different PV array orientations.

Kelowna, British Columbia/Colombie-Britannique
Geographic location -> -119.45E,49.88N

PV potential (kWh/kW)

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°
January	42	42	44	38
February	58	63	64	58
March	85	105	102	102
April	78	115	105	119
May	73	122	107	132
June	68	122	104	134
July	75	134	115	146
August	83	131	118	138
September	91	120	114	119
October	81	93	93	87
November	49	50	52	45
December	36	35	38	32
Annual	819	1133	1056	1151

Mean daily global insolation (MJ/m^2)

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°	Two-axis sun-tracking	Horizontal (tilt=0°)
January	6.6	6.5	6.9	5.9	7.7	3.9
February	10.0	10.8	10.9	10.0	12.8	7.2
March	13.2	16.3	15.8	15.8	20.8	12.3
April	12.5	18.4	16.9	19.1	26.1	17.2
May	11.3	18.9	16.6	20.4	28.9	20.9
June	10.8	19.6	16.7	21.5	32.3	22.7
July	11.6	20.7	17.8	22.6	34.1	23.8
August	12.9	20.4	18.2	21.4	30.8	20.0
September	14.5	19.2	18.3	19.1	26.1	14.2
October	12.5	14.3	14.4	13.5	18.0	8.6
November	7.9	8.0	8.4	7.3	9.6	4.2
December	5.6	5.5	5.8	4.9	6.4	2.9
Annual	10.8	14.9	13.9	15.1	21.2	13.2

Mean daily global insolation (kWh/m^2)

Appendix D

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°	Two-axis sun-tracking	Horizontal (tilt=0°)
January	1.8	1.8	1.9	1.6	2.1	1.1
February	2.8	3.0	3.0	2.8	3.6	2.0
March	3.7	4.5	4.4	4.4	5.8	3.4
April	3.5	5.1	4.7	5.3	7.3	4.8
May	3.1	5.3	4.6	5.7	8.0	5.8
June	3.0	5.4	4.6	6.0	9.0	6.3
July	3.2	5.8	4.9	6.3	9.5	6.6
August	3.6	5.7	5.1	6.0	8.6	5.6
September	4.0	5.3	5.1	5.3	7.3	4.0
October	3.5	4.0	4.0	3.8	5.0	2.4
November	2.2	2.2	2.3	2.0	2.7	1.2
December	1.6	1.5	1.6	1.4	1.8	0.8
Annual	3.0	4.1	3.9	4.2	5.9	3.7

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Appendix D

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Photovoltaic potential and solar resource maps of Canada

Photovoltaic (PV) potential (kWh/kW) and mean daily global insolation (MJ/m^2 and kWh/m^2) data are presented below for the selected municipality. Data is presented for each month and on a yearly basis for 6 different PV array orientations.

Victoria, British Columbia/Colombie-Britannique
Geographic location -> -123.37E,48.43N

PV potential (kWh/kW)

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°
January	43	43	45	38
February	52	57	58	53
March	74	95	91	92
April	71	108	98	112
May	67	118	103	127
June	63	118	101	131
July	70	130	112	142
August	78	128	115	135
September	91	123	117	121
October	76	88	88	82
November	45	47	48	42
December	40	39	41	34
Annual	771	1091	1017	1110

Mean daily global insolation (MJ/m^2)

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°	Two-axis sun-tracking	Horizontal (tilt=0°)
January	6.6	6.7	7.0	6.0	7.8	3.4
February	8.9	9.7	9.9	9.1	11.7	6.5
March	11.5	14.7	14.2	14.3	18.9	11.3
April	11.4	17.2	15.7	17.9	24.3	16.3
May	10.4	18.3	15.9	19.7	28.3	20.5
June	10.1	19.0	16.2	20.9	31.2	21.9
July	10.9	20.1	17.4	22.0	33.0	23.2
August	12.1	19.8	17.8	20.9	30.2	19.8
September	14.6	19.6	18.7	19.4	26.9	14.6
October	11.8	13.6	13.6	12.8	16.9	8.3
November	7.2	7.5	7.8	6.8	8.8	3.9
December	6.1	6.0	6.4	5.3	7.1	2.7
Annual	10.1	14.4	13.4	14.6	20.5	12.7

Mean daily global insolation (kWh/m^2)

Appendix E

	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=latitude+15°	South-facing, tilt=latitude-15°	Two-axis sun-tracking	Horizontal (tilt=0°)
January	1.8	1.9	2.0	1.7	2.2	0.9
February	2.5	2.7	2.8	2.5	3.3	1.8
March	3.2	4.1	3.9	4.0	5.3	3.1
April	3.2	4.8	4.4	5.0	6.8	4.5
May	2.9	5.1	4.4	5.5	7.9	5.7
June	2.8	5.3	4.5	5.8	8.7	6.1
July	3.0	5.6	4.8	6.1	9.2	6.5
August	3.4	5.5	4.9	5.8	8.4	5.5
September	4.1	5.5	5.2	5.4	7.5	4.1
October	3.3	3.8	3.8	3.6	4.7	2.3
November	2.0	2.1	2.2	1.9	2.4	1.1
December	1.7	1.7	1.8	1.5	2.0	0.7
Annual	2.8	4.0	3.7	4.1	5.7	3.5

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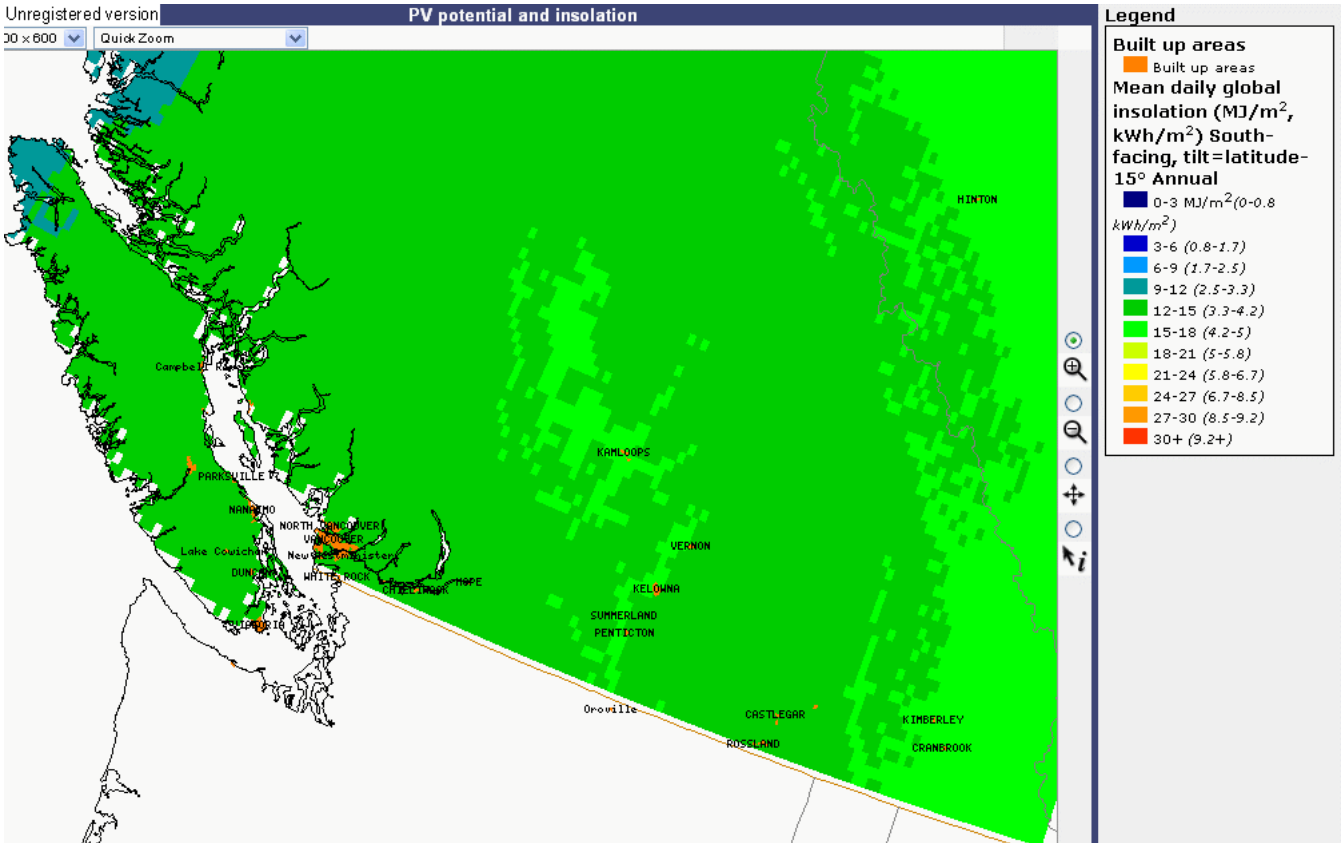
Appendix E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PV potential and insolation
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Built up areas
Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° Annual
0-3 MJ/m2 (0-0.8 kWh/m2)
3-6 (0.8-1.7)
6-9 (1.7-2.5)
9-12 (2.5-3.3)
12-15 (3.3-4.2)
15-18 (4.2-5)
18-21 (5-5.8)
21-24 (5.8-6.7)
24-27 (6.7-8.5)
27-30 (8.5-9.2)
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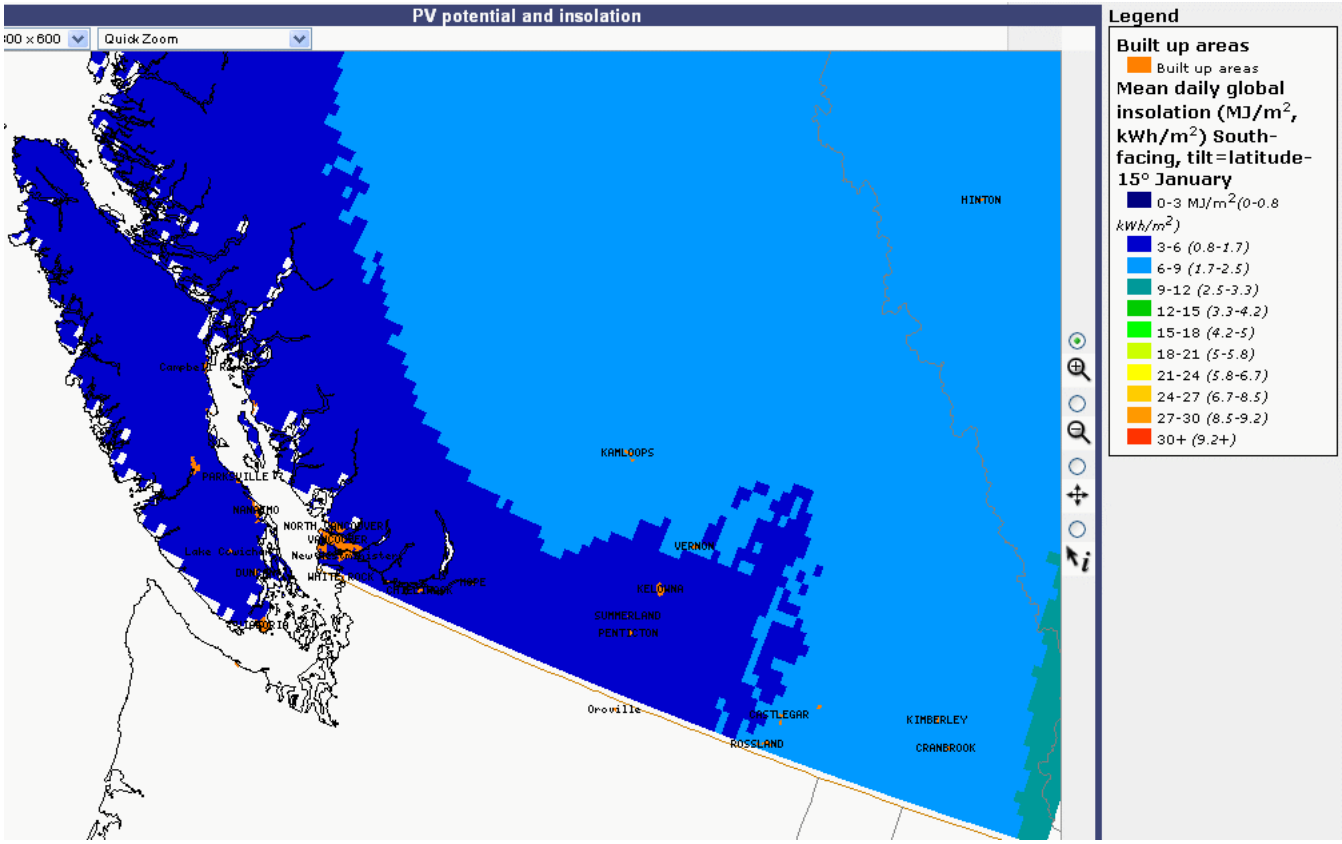
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15-18 (4.2-5)
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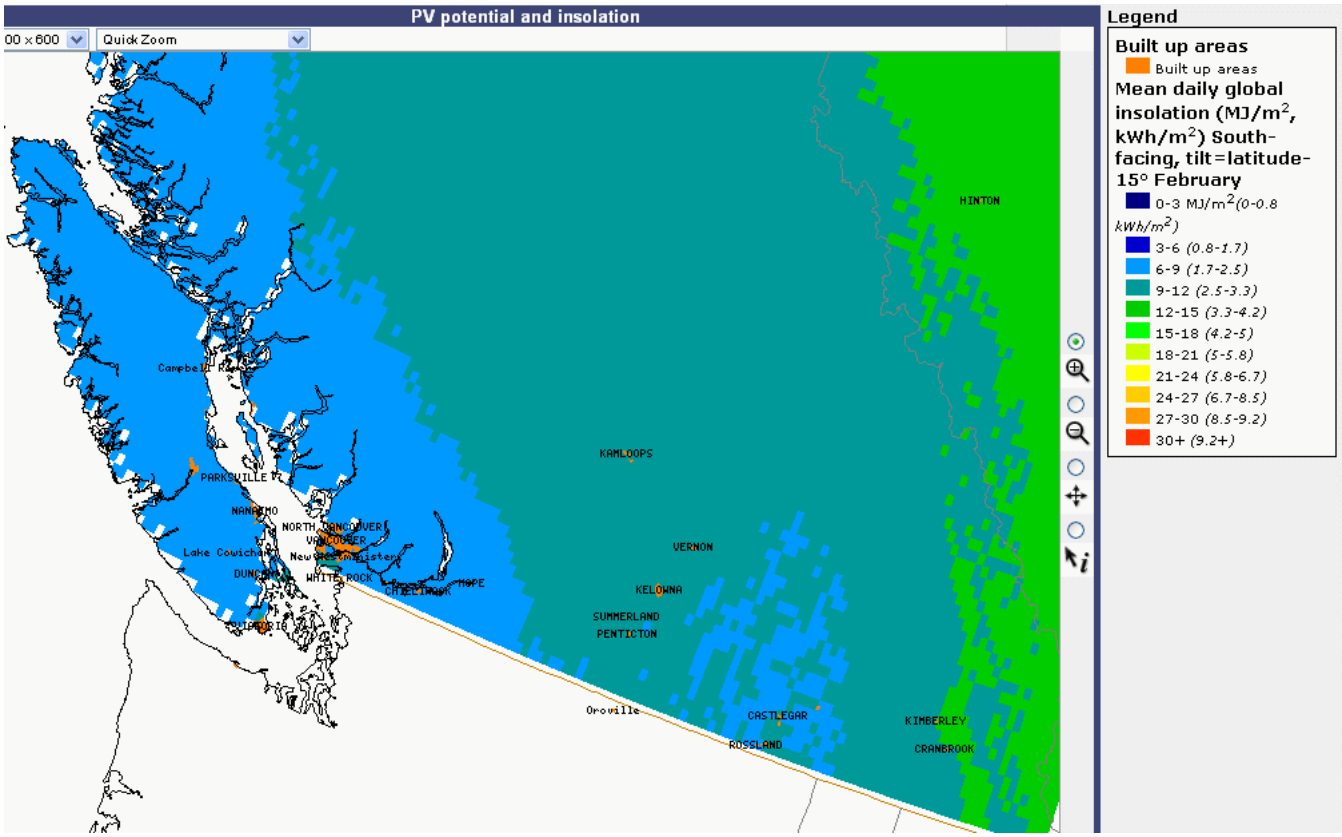
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3-6 (0.8-1.7)
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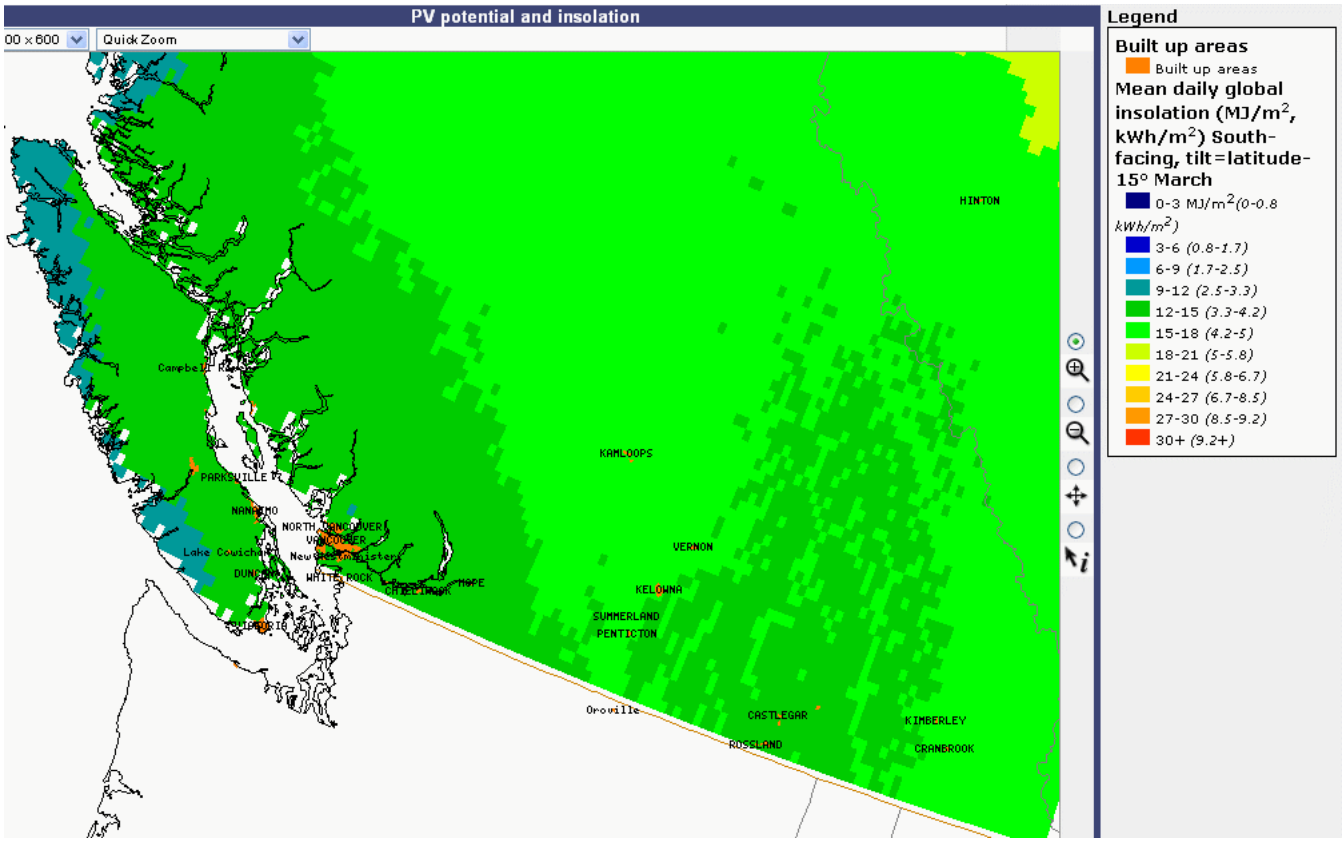
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Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° March
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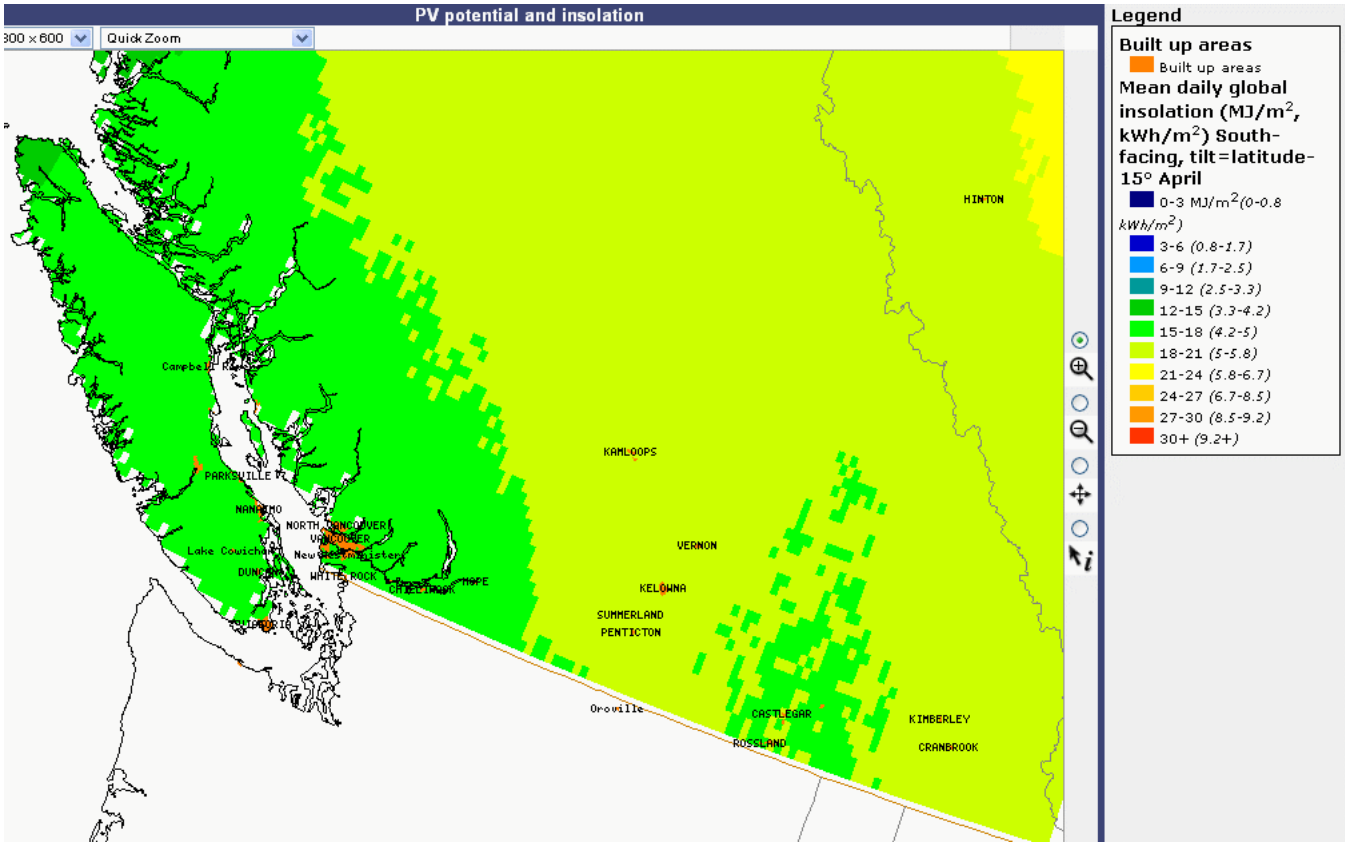
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3-6 (0.8-1.7)
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9-12 (2.5-3.3)
12-15 (3.3-4.2)
15-18 (4.2-5)
18-21 (5-5.8)
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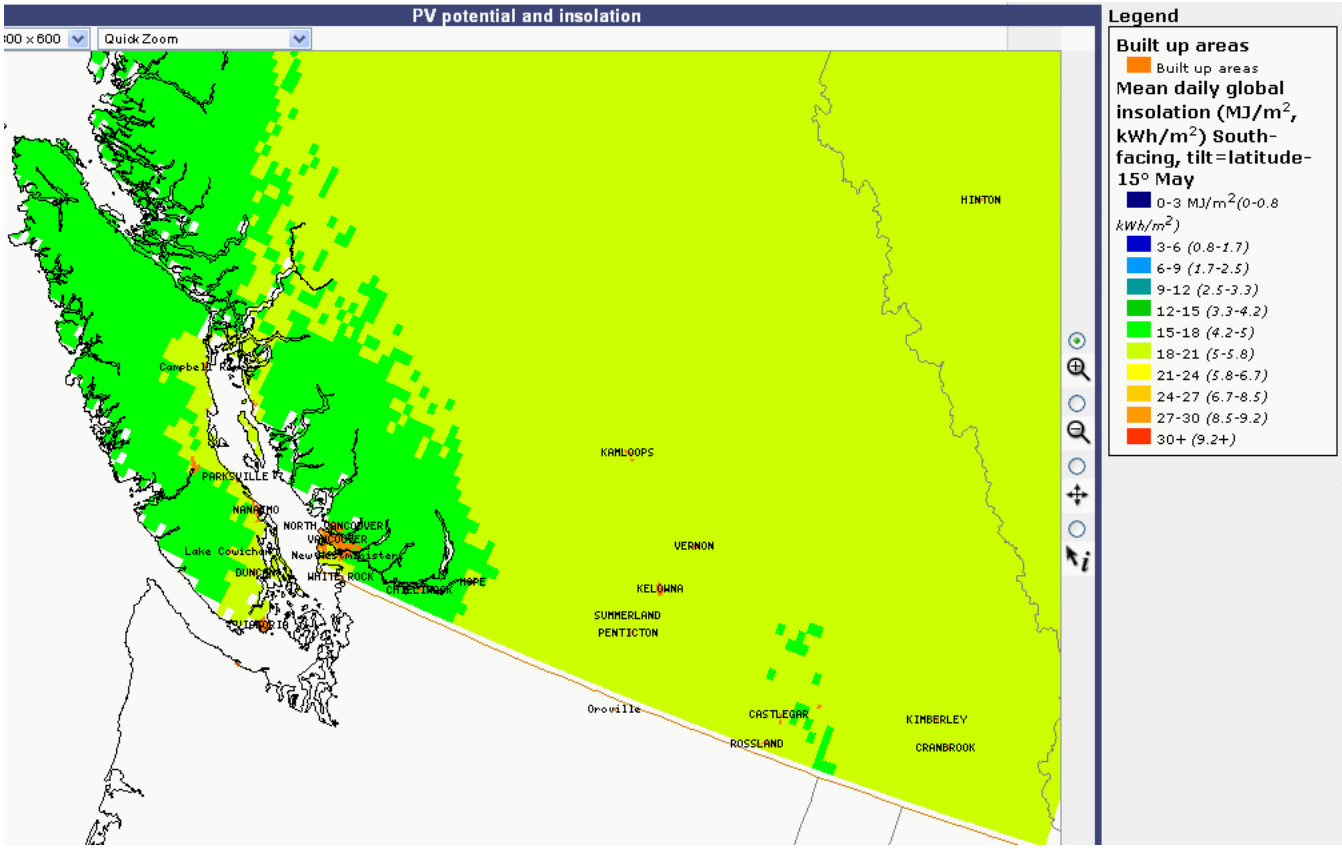
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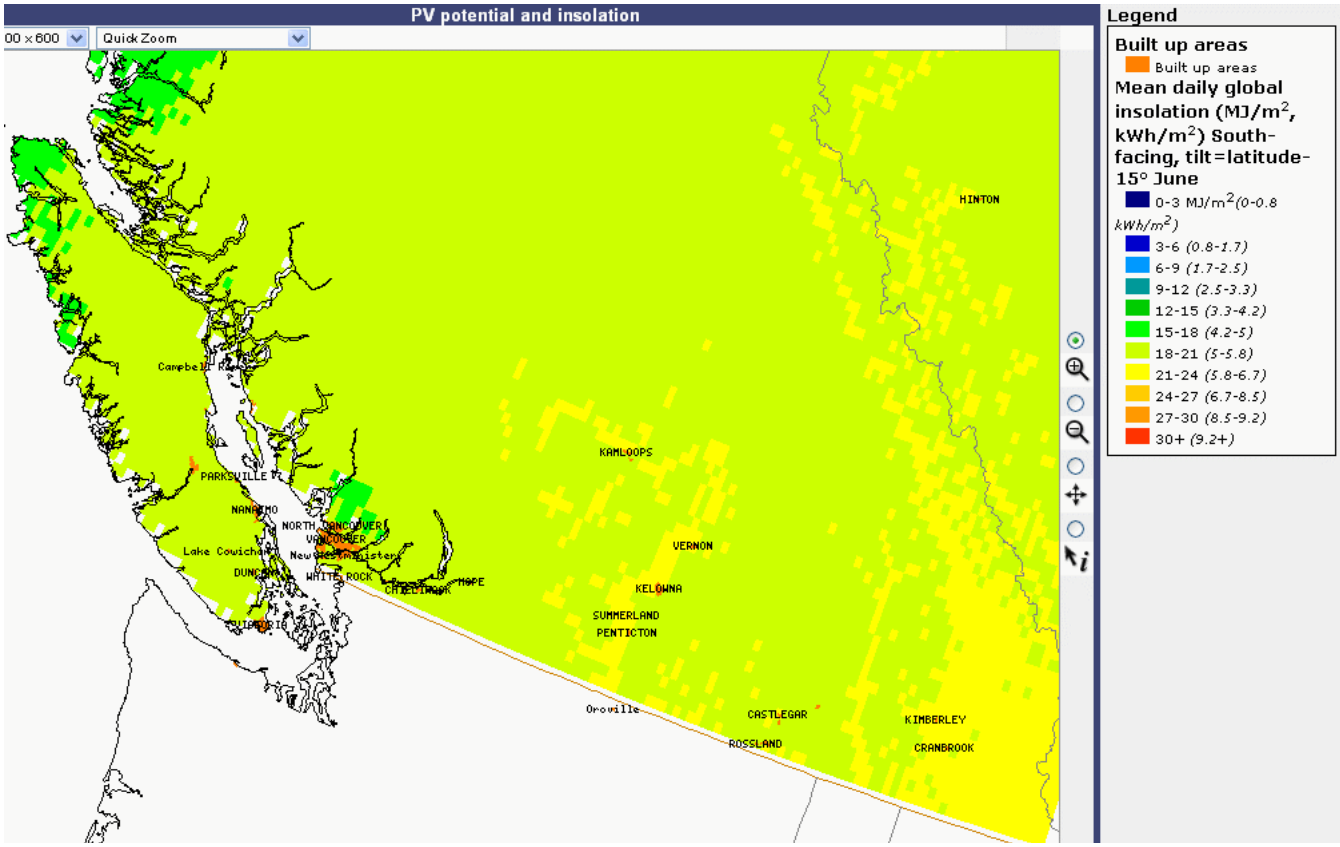
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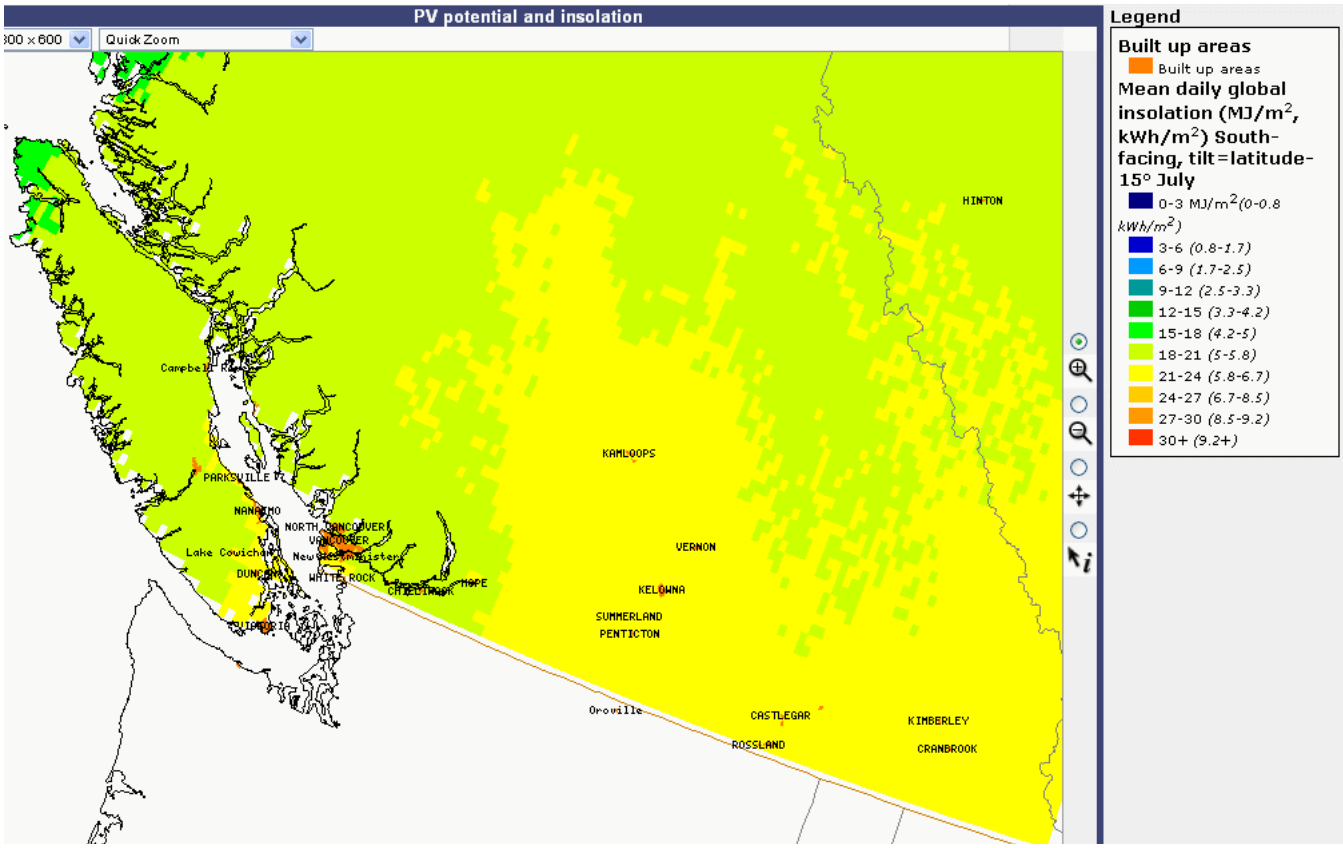
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12-15 (3.3-4.2)
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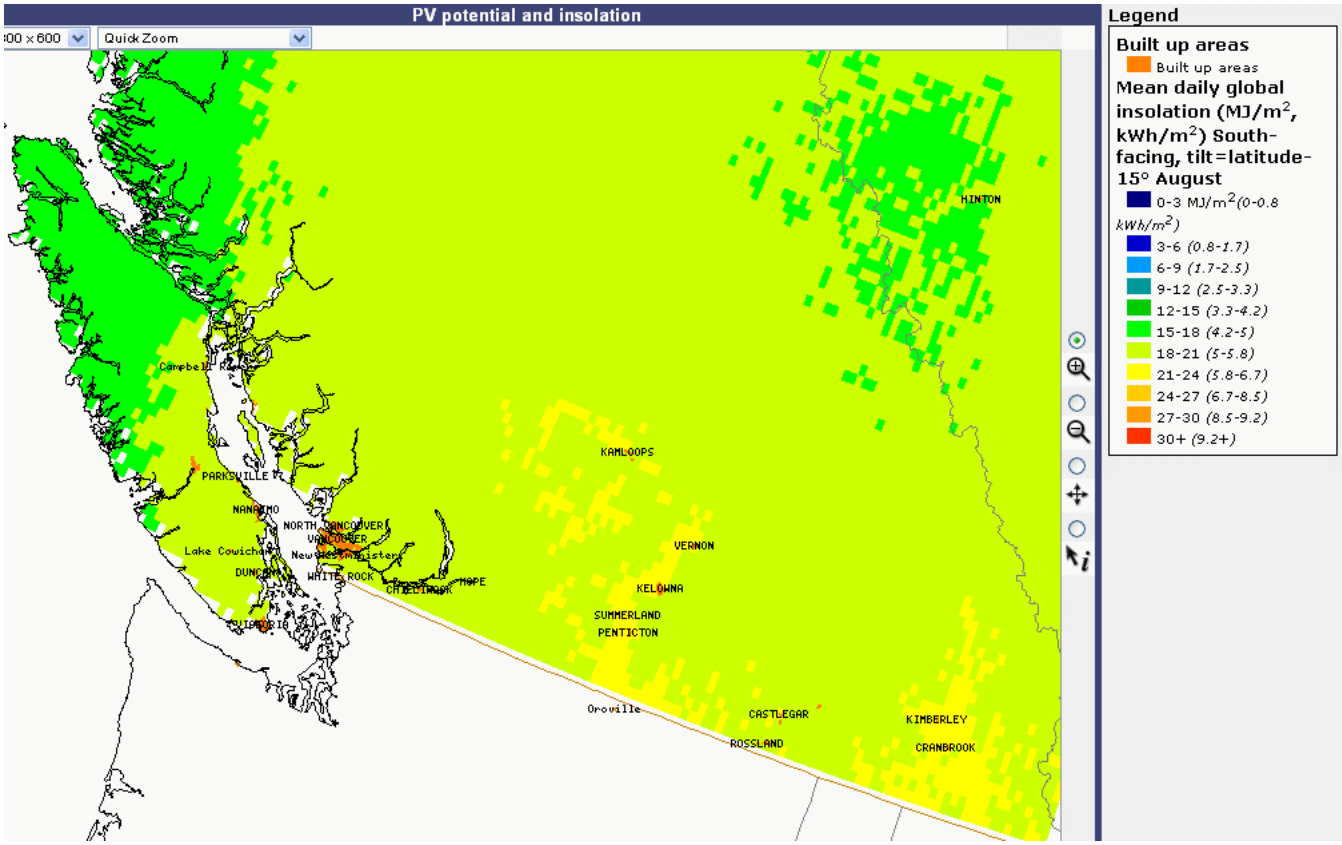
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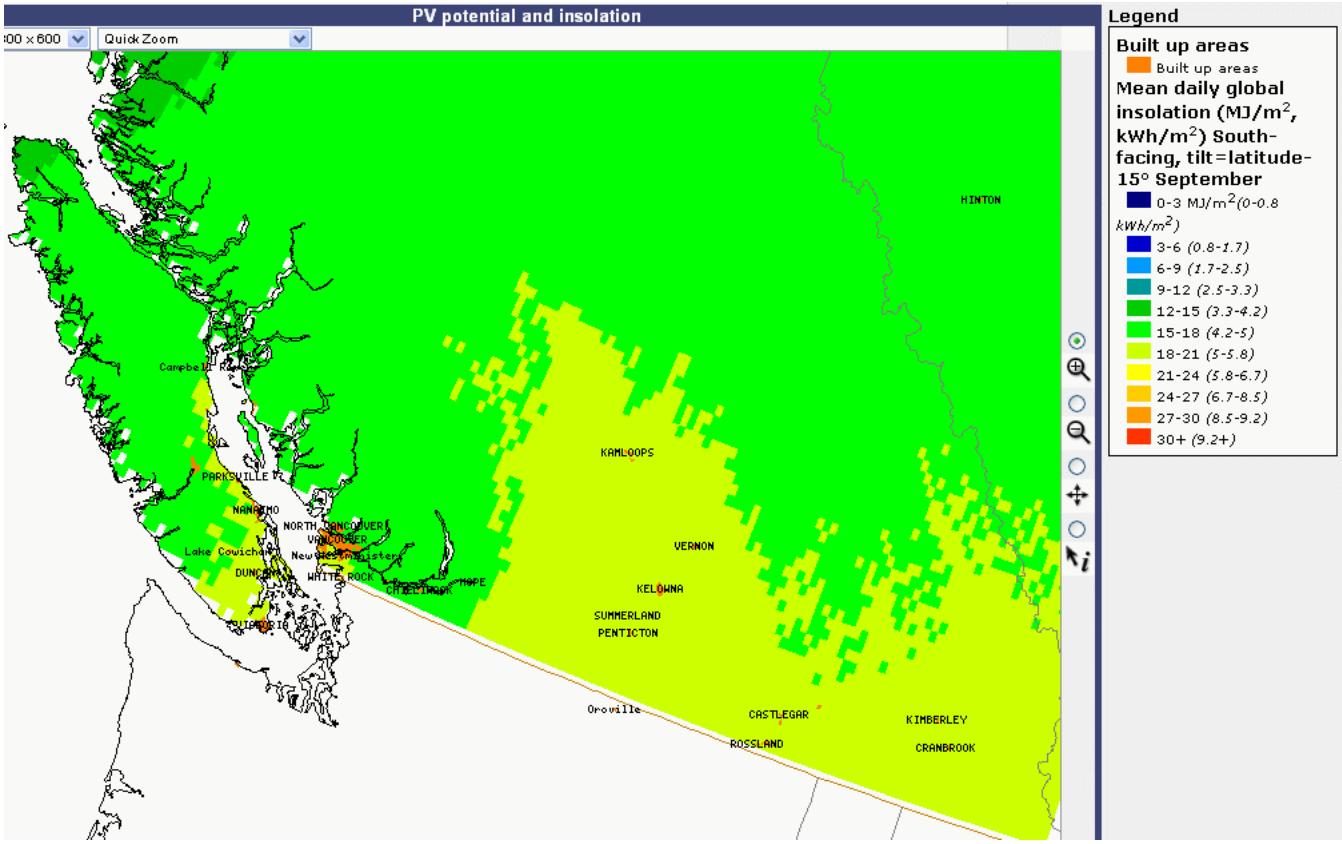
PV potential and insolation
Quick Zoom
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Built up areas
Built up areas
Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° September
0-3 MJ/m2 (0-0.8 kWh/m2)
3-6 (0.8-1.7)
6-9 (1.7-2.5)
9-12 (2.5-3.3)
12-15 (3.3-4.2)
15-18 (4.2-5)
18-21 (5-5.8)
21-24 (5.8-6.7)
24-27 (6.7-8.5)
27-30 (8.5-9.2)
30+ (9.2+)
HINTON
KAMLOOPS
VERNON
KELOWNA
SUMMERLAND
PENTICTON
Oroville
CASTLEGAR
ROSSLAND
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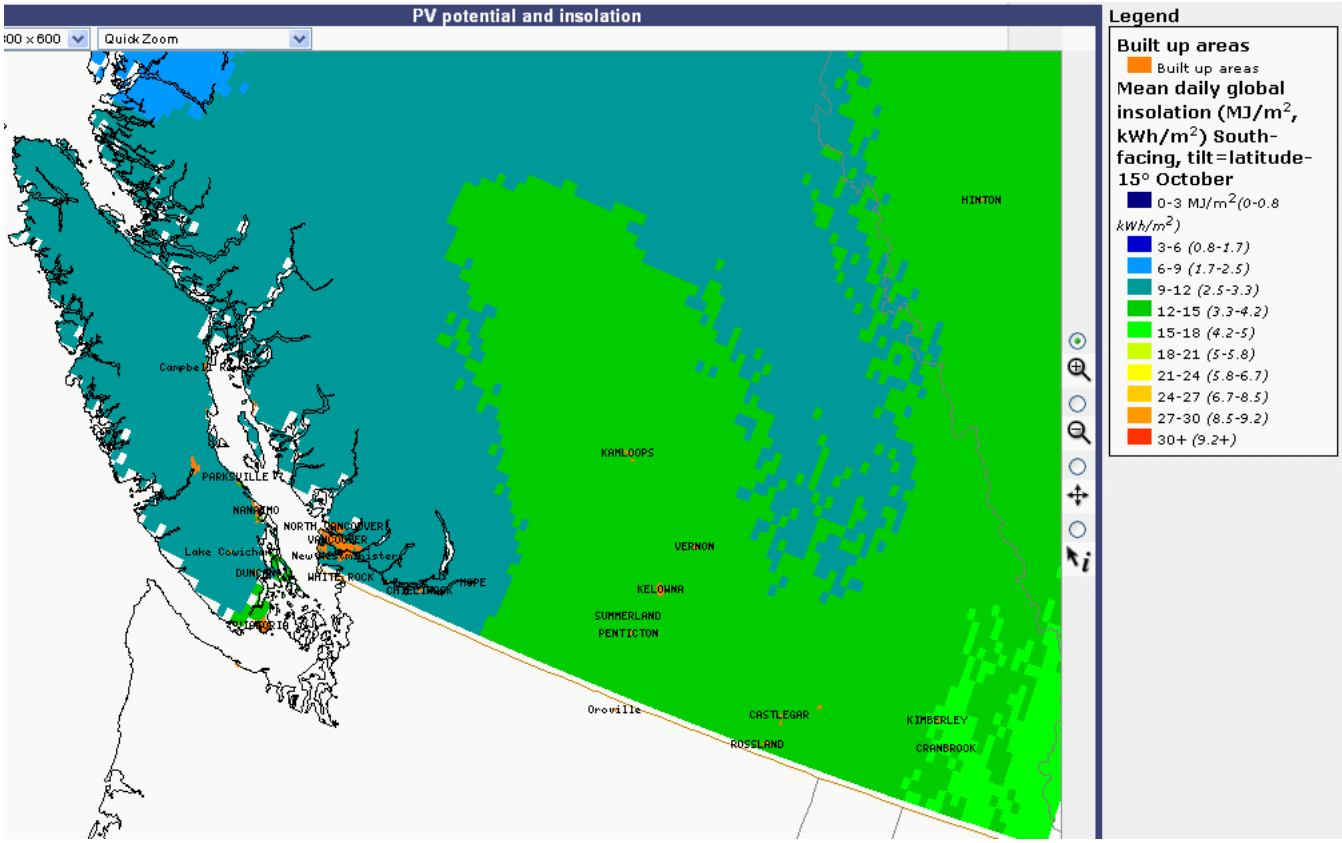
VANCOUVER
Lake Cowichan
New Westminster
DUNCAN
WHITE ROCK
HOPE
VICTORIA


PV potential and insolation
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Built up areas
Built up areas
Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° October
0-3 MJ/m2 (0-0.8 kWh/m2)
3-6 (0.8-1.7)
6-9 (1.7-2.5)
9-12 (2.5-3.3)
12-15 (3.3-4.2)
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New Westminster
WHITE ROCK
HOPE
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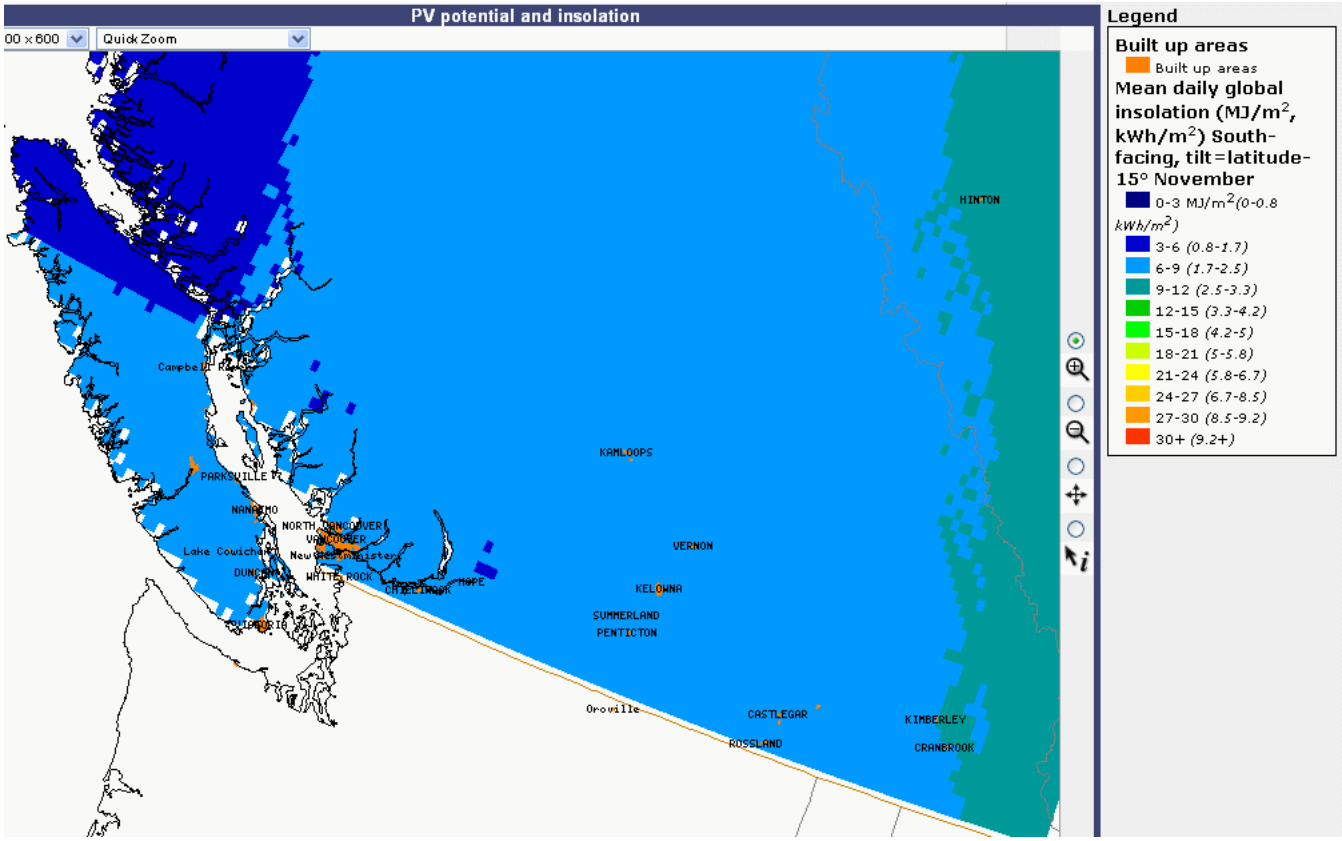
PV potential and insolation
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Built up areas
Built up areas
Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° November
0-3 MJ/m2 (0-0.8 kWh/m2)
3-6 (0.8-1.7)
6-9 (1.7-2.5)
9-12 (2.5-3.3)
12-15 (3.3-4.2)
15-18 (4.2-5)
18-21 (5-5.8)
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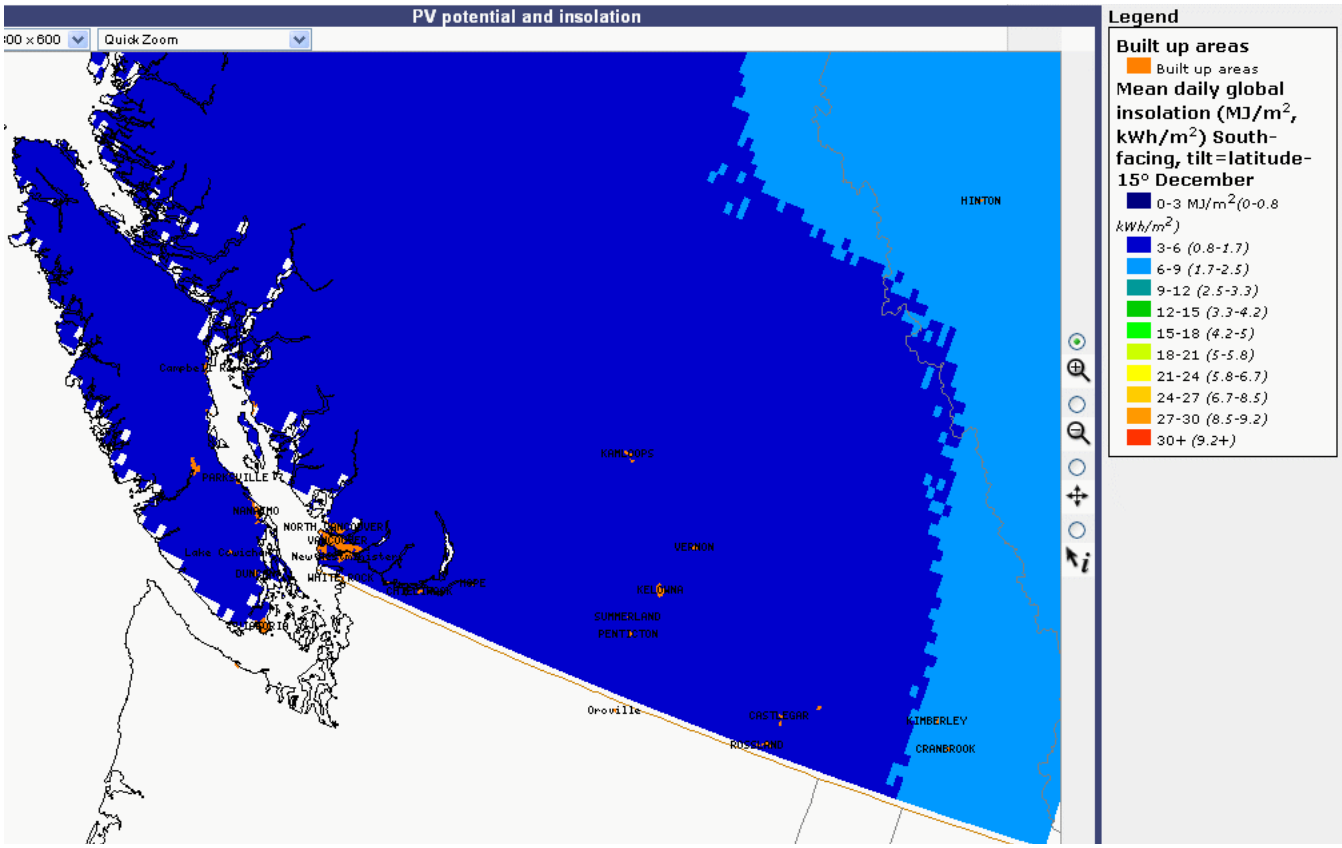
PV potential and insolation
Quick Zoom
HINTON
KAMLOOPS
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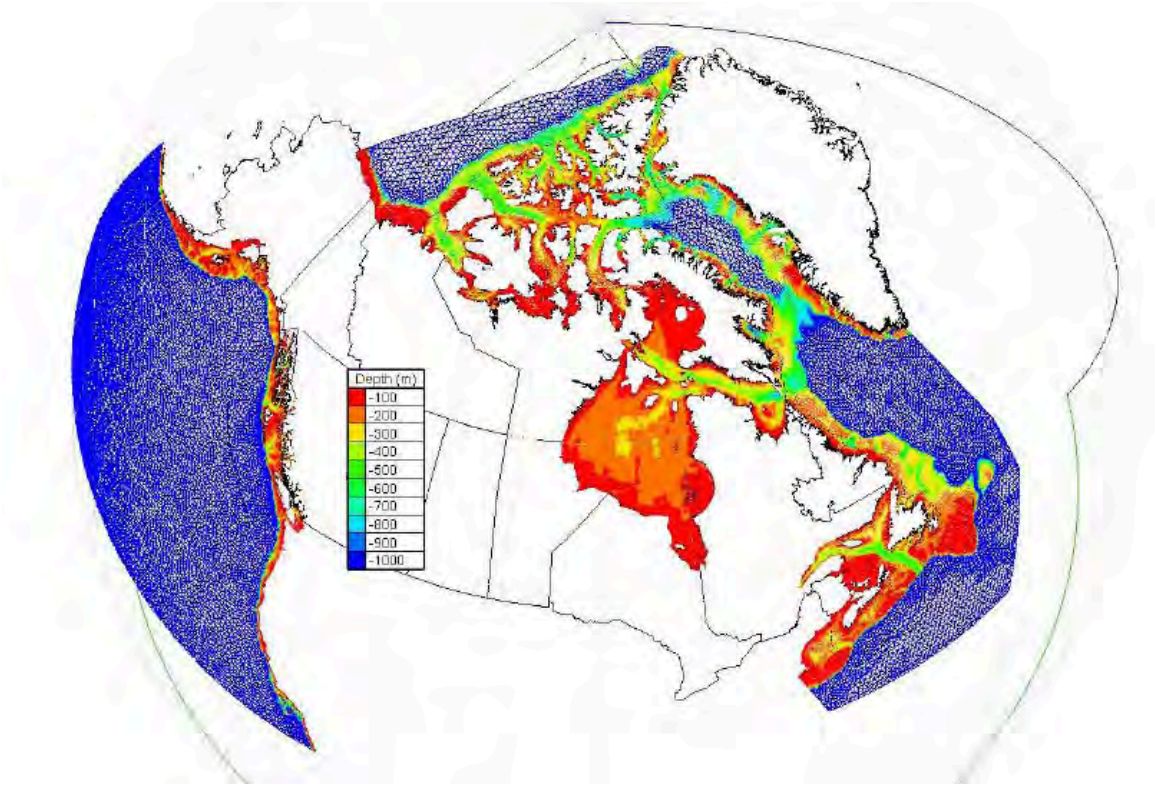
NANAIMO
VERNON
KELOWNA
SUMMERLAND
PENTICTON
Oroville
CASTLEGAR
KIMBERLEY
CRANBROOK
Legend
Built up areas
Built up areas
Mean daily global insolation (MJ/m2, kWh/m2) South-facing, tilt=latitude-15° December
0-3 MJ/m2 (0-0.8 kWh/m2)
3-6 (0.8-1.7)
6-9 (1.7-2.5)
9-12 (2.5-3.3)
12-15 (3.3-4.2)
15-18 (4.2-5)
18-21 (5-5.8)
21-24 (5.8-6.7)
24-27 (6.7-8.5)
27-30 (8.5-9.2)
30+ (9.2+)

CANADIAN HYDRAULICS CENTRE
CENTRE D'HYDRAULIQUE CANADIEN

INVENTORY OF CANADA'S MARINE RENEWABLE ENERGY RESOURCES



A. Cornett

CHC-TR-041

April 2006

National Research Council Canada
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Appendix G

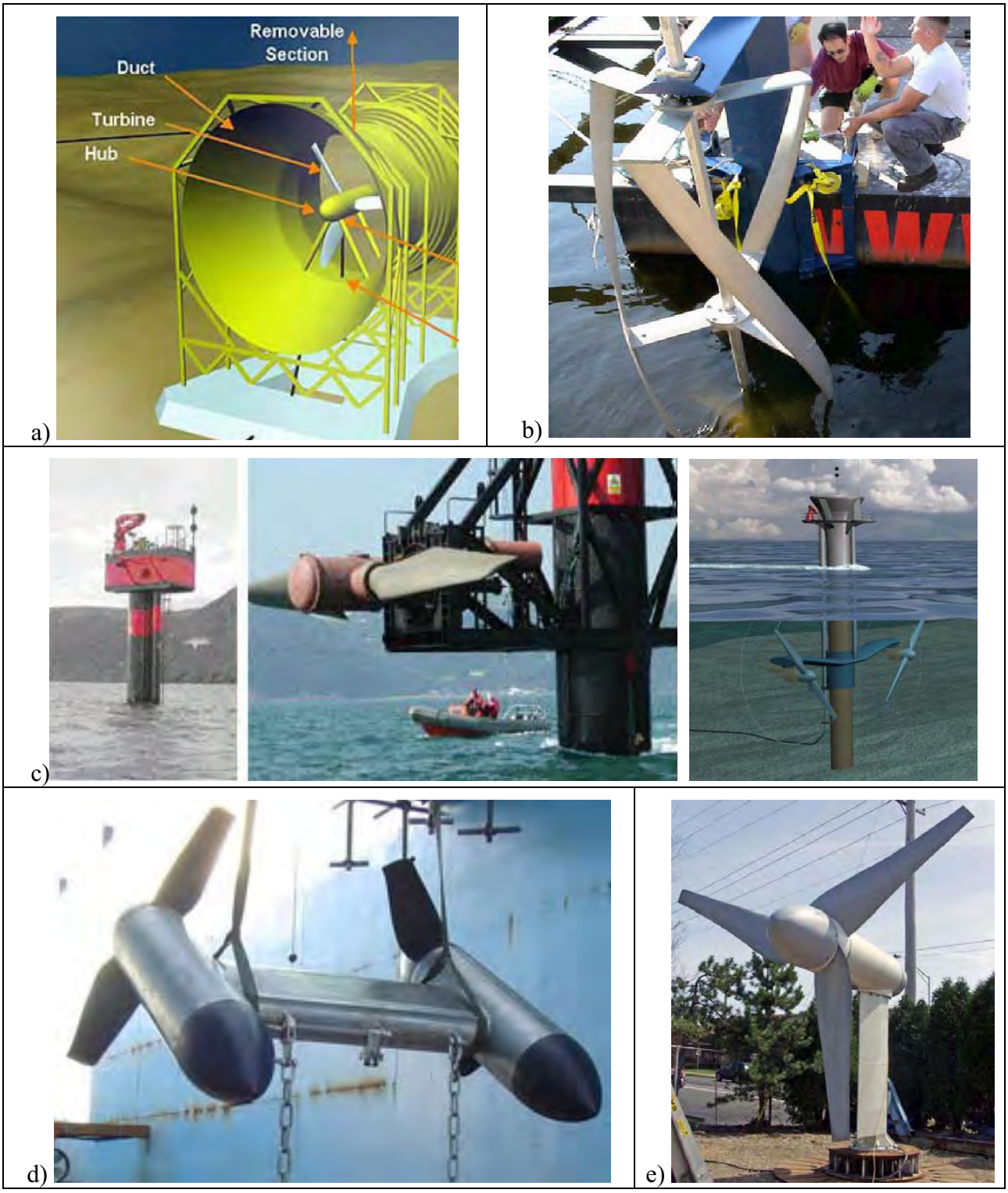


Figure 1. Five examples of kinetic hydraulic turbines: a) Lunar Energy; b) GCK Technology; c) MCT SeaGen; d) SMD Hydrovision TidEL; e) Verdant Power.

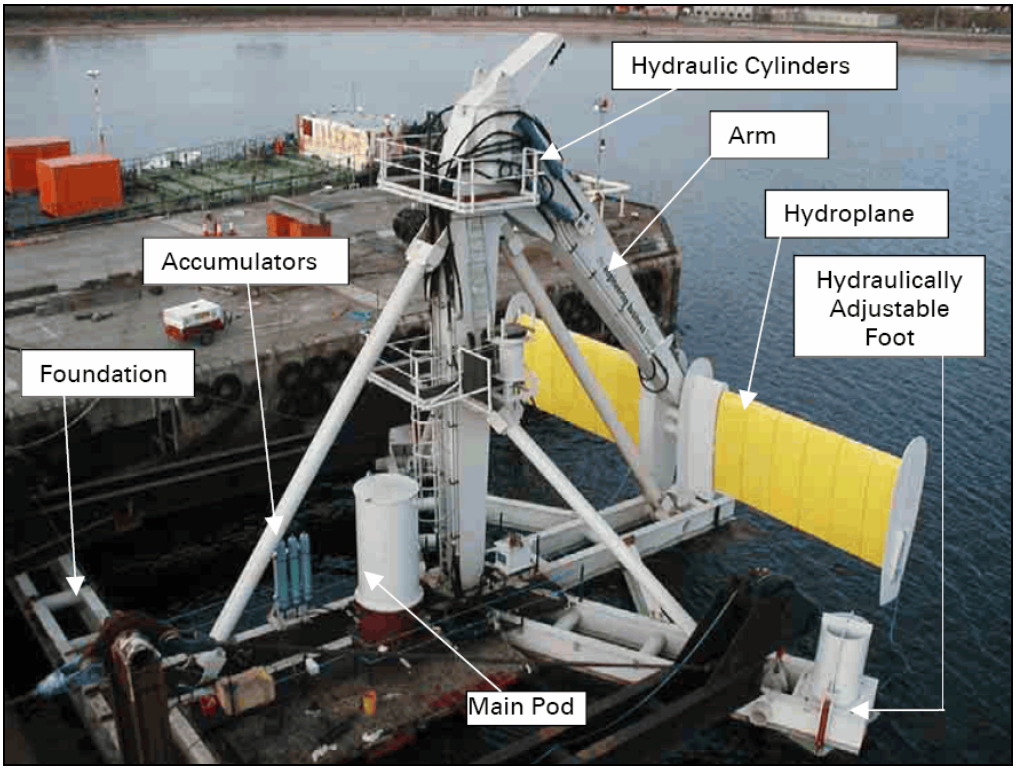


Figure 2. Stingray tidal stream generator prior to deployment.

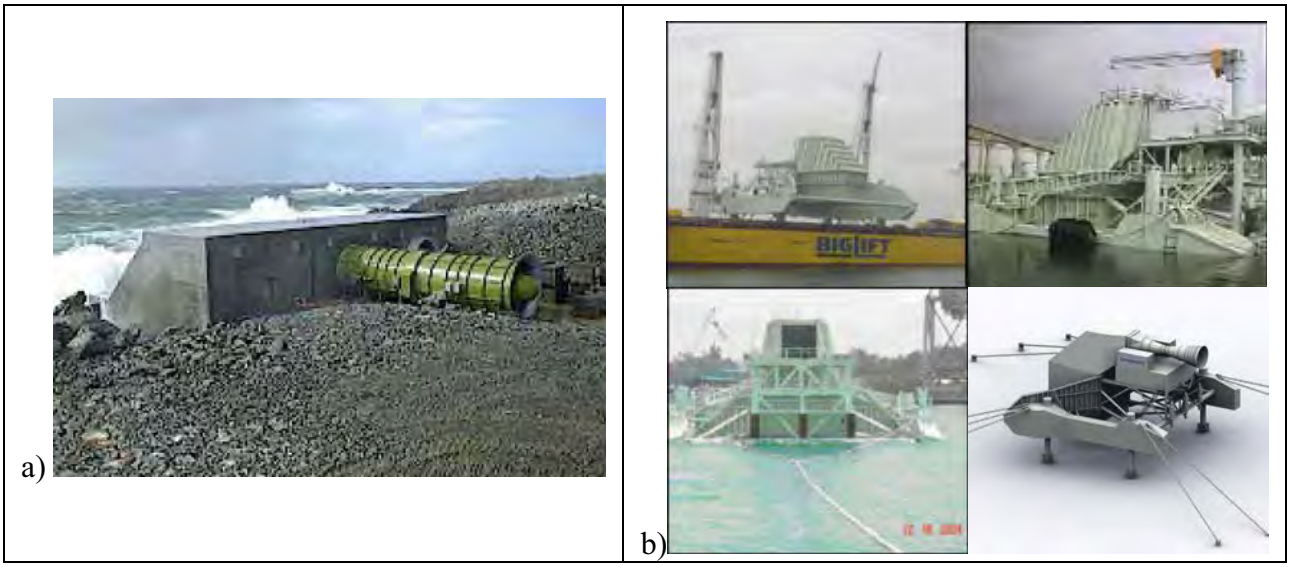


Figure 3. Two examples of nearshore wave energy converters: a) Limpet OWC; b) Energetech OWC.

Figure 4. Six examples of offshore wave energy converters: a) Pelamis; b) Archimedes Wave Swing; c) IPS Buoy; d) Technocean Hose-Pump; e) Wave Dragon; f) OPT PowerBuoy.

				Mean Wave Power (kW/m)												
Station ID	Station Name	Long	Lat	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
C46004	Middle Nomad	-135.87	50.94	53.8	89.4	80.4	64.8	51.0	27.0	17.9	11.1	14.8	33.3	64.9	96.8	113.8
C46036	South Nomad	-133.86	48.3	53.3	90.8	79.2	73.8	50.7	26.6	19.6	11.3	15.0	27.2	59.2	86.8	107.1
meds503w	Queen Charlotte	-129.97	51.3	52.9	103.4	73.8	57.6	72.9	25.3	22.7	10.5	10.5	22.3	35.9	83.9	85.8
C46184	North Nomad	-138.76	53.96	50.9	79.6	73.0	62.5	44.6	22.7	16.8	10.3	14.7	35.3	62.6	84.9	103.3
C46207	East Dellwood	-129.91	50.86	49.0	82.4	75.3	59.9	39.3	22.1	16.1	9.9	11.4	23.9	56.7	77.4	100.5
C46147	South Moresby	-131.2	51.82	49.0	79.4	82.3	64.9	42.1	21.8	16.9	10.1	11.8	26.3	63.1	79.1	101.0
meds211	Langara West	-133.32	54.45	45.7	106.2	101.3	55.9	48.7	20.7	12.3	7.8	9.6	21.0	37.7	63.3	72.3
C46208	West Moresby	-132.7	52.5	44.7	72.8	69.7	56.6	39.1	22.8	16.2	9.7	12.8	25.8	56.0	73.0	95.8
C46205	West Dixon Entrance	-133.4	54.3	43.6	73.0	57.6	53.1	40.0	23.3	15.3	9.5	13.3	28.2	53.5	81.2	91.0
meds226	Cape Scott	-128.91	50.77	43.3	101.1	53.9	49.9	54.4	22.4	11.7	7.2	13.5	15.4	55.7	29.3	53.0
C46132	South Brooks	-127.92	49.73	43.3	71.7	71.8	60.0	35.8	19.4	15.1	9.0	9.8	21.4	51.2	67.0	87.1
meds103	Tofino	-125.74	48.99	31.9	58.2	53.5	45.6	32.5	18.6	12.4	7.8	8.3	13.7	34.2	52.2	55.7
C46204	West Sea Otter	-128.74	51.38	30.7	51.8	41.6	39.7	25.5	14.7	10.6	6.7	7.7	15.4	35.9	48.8	61.2
C46185	South Hecate Strait	-129.8	52.42	23.0	42.8	34.1	27.3	20.6	11.8	7.9	5.4	5.9	10.5	23.0	36.4	47.0
meds502w	Hecate Strait	-130.33	52.2	18.2	31.7	20.4	32.3	21.8	10.3	10.6	4.9	4.1	7.9	18.3	33.0	21.2
C46145	Central Dixon Entranc	-132.43	54.38	17.7	22.2	26.0	24.0	14.5	8.2	5.0	3.4	4.8	12.7	22.0	30.7	41.7
meds213	Bonilla Island	-130.72	53.32	12.1	23.2	13.9	16.4	14.4	7.7	4.8	3.2	2.6	4.9	10.1	24.4	17.6
C46183	North Hecate Strait	-131.14	53.57	11.2	21.3	16.9	13.0	10.4	5.0	3.0	2.3	3.5	5.3	11.5	17.9	24.0
C46131	Sentry Shoal	-124.99	49.91	0.6	0.8	0.5	0.8	0.6	0.2	0.2	0.1	0.1	0.2	0.7	1.1	1.2
meds108	Roberts Bank	-123.27	49.02	0.4	0.2	0.5	0.6	0.4	0.4	0.6	0.2	0.2	0.2	0.4	0.5	0.5
meds102	Sturgeon Bank	-123.31	49.17	0.4	0.3	0.4	0.5	0.5	0.3	0.4	0.2	0.2	0.2	0.3	0.4	0.4
C46146	Halibut Bank	-123.73	49.34	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.6
meds122	Point Grey	-123.27	49.28	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.2	0.3
meds106	West Vancouver	-123.23	49.35	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1
meds123	Fishermans Cove (WB)	-123.7	49.35	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.1
C46181	Nanakwa Shoal	-128.84	53.82	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
meds317	Esquimalt Harbour	-123.45	48.43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
meds124	Fishermans Cove (K)	-123.27	49.35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C46134	Pat Bay Test Buoy	-123.45	48.66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
meds121	Gibsons Landing	-123.5	49.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 7. Annual and monthly mean wave power for Pacific stations.

Many stations on both coasts are located in sheltered inshore locations with relatively mild wave climates. However, there are also a good number of stations in exposed sites featuring energetic wave climates. These results indicate that the mean annual wave energy flux at exposed sites in deep water off the B.C. coast is typically in the range of 45 to 55 kW/m, while the mean wave power available near the western shores of the Queen Charlotte Islands and Vancouver Island is on the order of 30 to 45 kW/m. On the Grand Banks east of Newfoundland, the mean annual wave energy flux is in the range of 42 to 45 kW/m, while the mean wave power available near the SE coast of Newfoundland is on the order of 25 to 30 kW/m. Annual mean wave power values around 20 to 25 kW/m seem representative for the waters near Sable Island, while values near 10 kW/m are representative of conditions along the southern shore of Nova Scotia.

As noted previously, the wave power along a coast can vary considerably due to sheltering and bathymetric effects such as wave diffraction and refraction. Hence, there likely will be pronounced local variations in wave conditions and energy potential close to shore. Clearly, these local variations cannot be identified and are beyond the scope of the present analysis.

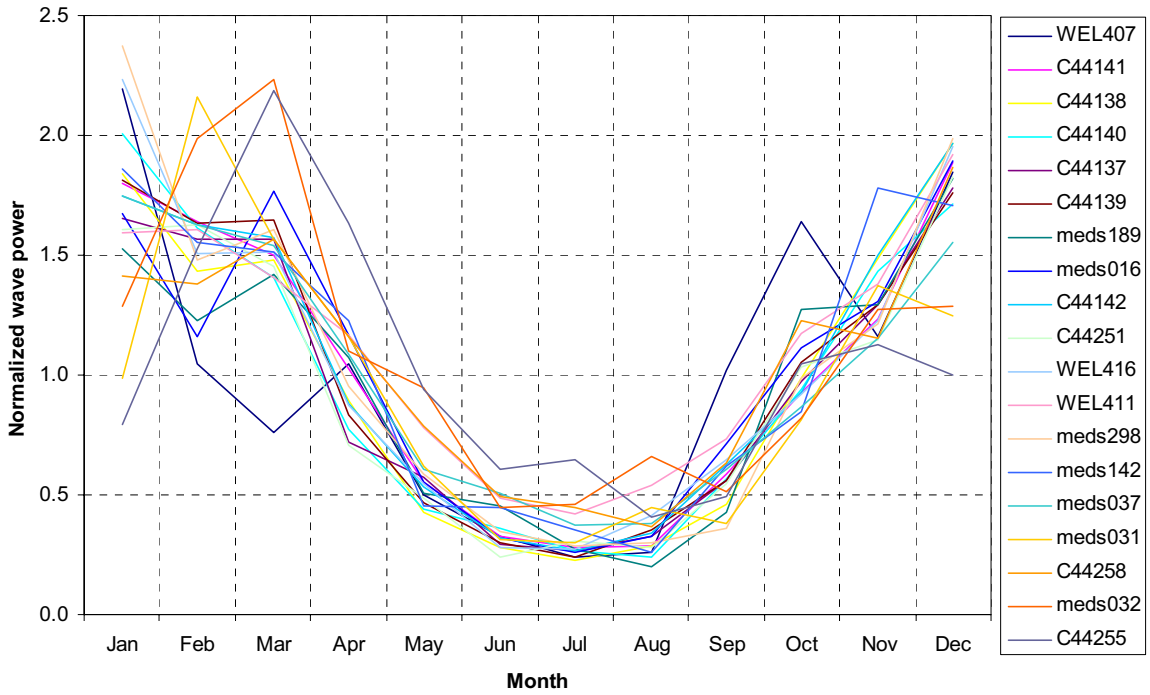


Figure 12. Seasonal variation in mean wave power for Atlantic stations.

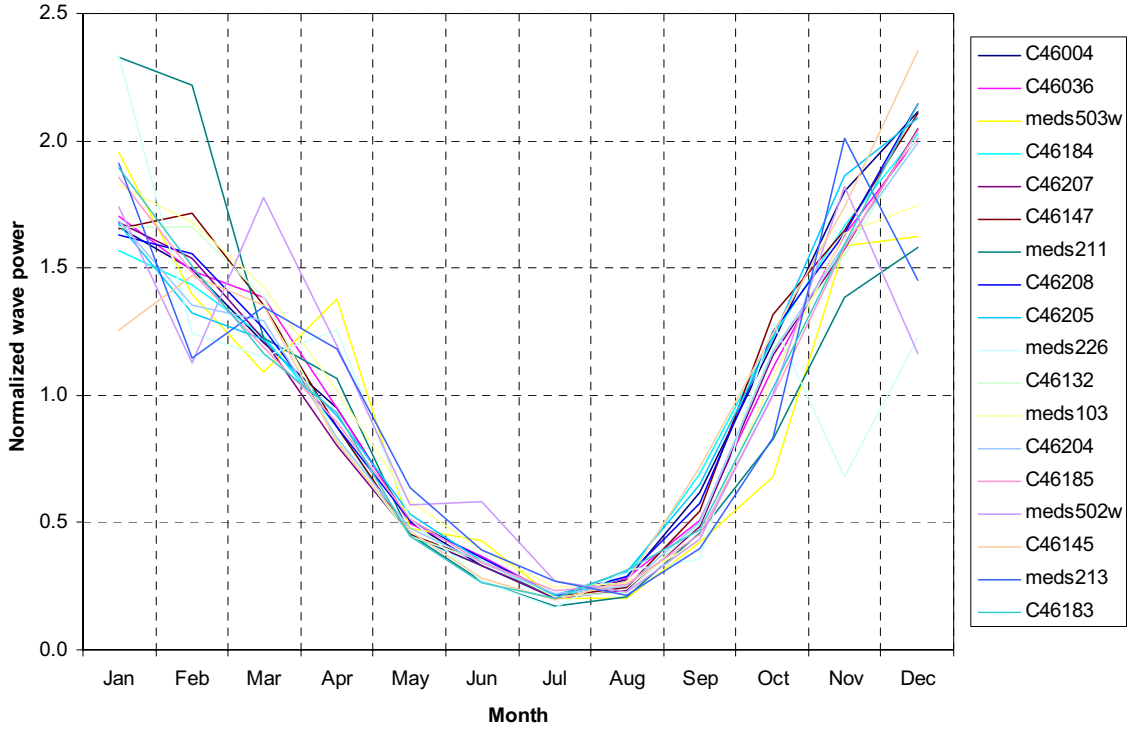


Figure 13. Seasonal variation in mean wave power for Pacific stations.

3.5.2. Results

The mean annual wave power computed from the WW3-ENP data is plotted in Figure 18. The mean wave power in winter and summer are compared in Figure 19.

Figure 20 shows the mean annual wave power computed from the WW3-WNA data. The mean wave power in summer and winter are compared in Figure 21.

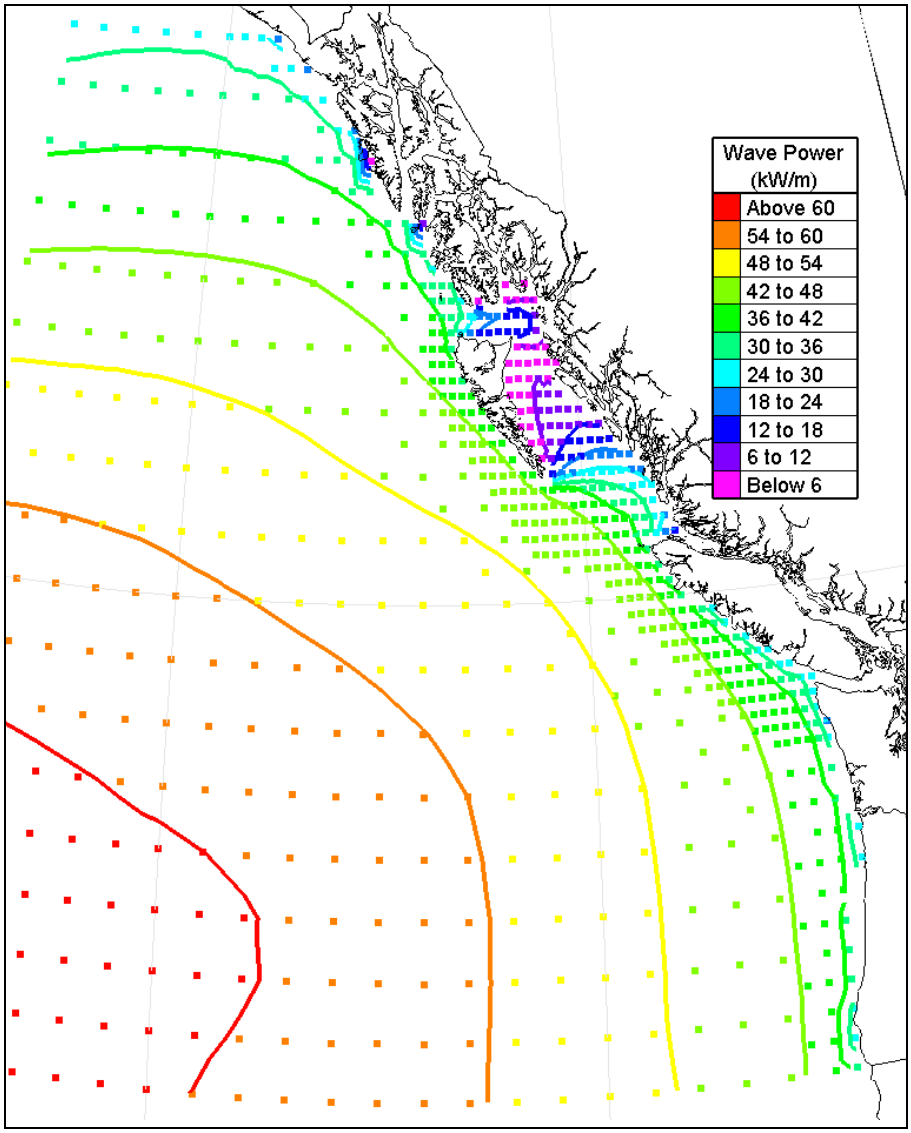


Figure 18. Mean annual wave power in the NE Pacific derived from WW3-ENP hindcast data. (points denote sub-grid nodes.)

where V_f is the maximum speed at the surface in the passage during a large flood, V_e is the maximum surface speed during a large ebb, and the factor 0.85 accounts for the lateral and vertical velocity variations across the channel. The annual mean power density is computed as

$$\overline{p} = \frac{2\rho}{3\pi}\frac{\left(a_f U_{\max}\right)^3 + \left(a_e U_{\max}\right)^3}{2} \tag{23}$$

Where $a_f U_{max}$ denotes the annual mean peak flood current velocity, and $a_e U_{max}$ denotes the annual mean of the current velocity at peak ebb. Triton assumed $a_f = 0.9$ and $a_e = 0.7$ at all locations except in British Columbia, where diurnal tidal currents are particularly strong. It was assumed that $a_e = 0.5$ for sites in southern B.C., and $a_e = 0.6$ for sites in northern B.C.. The annual mean power at the site was calculated according to

$$\overline{P} = wh_{ave}\overline{p} \tag{24}$$

where w denotes the width of the passage and h_{ave} is the average depth.

4.4.2. Results

A total of 260 potential sites were identified. Of these, 190 sites had potential mean power estimated to be greater that 1 MW. Table 10 shows the cumulative mean potential tidal current energy by Province and Territory. Nunavut has by far the greatest potential resource (30,567 MW), while British Columbia has the most sites greater than 1 MW (89 sites). Table 11 shows the distribution of mean potential power by region. Over 70% of the Canada's tidal current energy resources lie within Hudson Strait, which connects Hudson Bay with Baffin Bay and the Northwest Atlantic.

Province	Potential Tidal Current Energy MW	Number of Sites	Average Size MW
Northwest Territories	35	4	9
British Columbia	4,015	89	45
Québec	4,288	16	268
Nunavut	30,567	34	899
New Brunswick	636	14	45
PEI	33	4	8
Nova Scotia	2,122	15	141
Newfoundland	544	15	36
TOTAL	42,240	191	221

Table 10. Mean potential tidal current energy by Province and Territory.

Region	Potential Tidal Current Energy MW	Number of Sites	Average Size MW
Vancouver Island Mainland	3,580	62	58
Pacific Mainland North	353	18	20
Queen Charlotte Islands	81	9	9
Arctic	1,008	30	34
Hudson Strait	29,595	8	3,699
Ungava	4,112	10	411
St. Lawrence River	153	4	38
Gulf of St Lawrence	537	15	36
Atlantic North	65	6	11
Atlantic South	30	8	4
Bay of Fundy	2,725	21	130
TOTAL	42,240	191	221

Table 11. Mean potential tidal current energy by region.

All sites in southern and northern British Columbia with mean power greater than 1 MW are summarized in Table 12 and Table 13 respectively. Table 14 lists the sites in the Northwest Territories; Table 15 shows the sites in Nunavut; Table 16 shows the sites in Québec; Table 17 shows the sites in Newfoundland and Labrador; while Table 18, Table 19, and Table 20 list the sites in Nova Scotia, Prince Edward Island and in New Brunswick.

The leading tidal current energy sites across Canada are also mapped in Figure 76. Figure 77 , Figure 78 and Figure 79 show detailed views of this map, centred on the Pacific coast, the Arctic Archipelago, and the Atlantic coast, respectively. In these maps, the size and colour of the circles are scaled and shaded in proportion to the mean potential power of each site.

This inventory, while likely not fully comprehensive, represents the best possible pan-Canadian assessment that could be made considering the level of funding, the available information, and the vast extent of Canada's coastal waters. Despite best efforts, it is entirely possible that some good potential sites have been missed. Hence, this inventory should be considered as a lower bound estimate to both the number of sites and the total tidal stream energy resource.

Site Name	Latitude	Longitude	Maximum Current Speed Flood	Maximum Current Speed Ebb	Mean Maximum Depth Average Current Speed	Mean Power Density	Width of Passage	Average Depth of Passage	Flow Cross-sectional Area	Mean Potential Power
	deg	deg	knot	m/s	m/s	kW/m^2	m	m	m^2	MW
Seymour Narrows	50.13	-125.35	16	14	6.56	18.16	769	41	33,331	786
N. Boundary Passage	48.79	-123.01	4	4	1.75	0.50	5,158	140	734,949	366
Discovery Pass. S.	50.00	-125.21	7	7	3.06	3.68	1,459	42	65,626	327
Boundary passage	48.69	-123.27	3.5	3.5	1.53	0.33	4,472	175	793,760	265
Current Passage 2	50.39	-125.86	6	6	2.63	1.68	1,502	80	123,931	208
Weyton Passage	50.59	-126.82	6	6	2.63	1.68	1,535	75	118,985	200
Current Passage 1	50.41	-125.87	5	5	2.19	0.97	1,398	100	143,331	139
Dent Rapids	50.41	-125.21	11	8	4.16	6.67	420	45	19,955	133
South Pender Is	48.72	-123.19	4	4	1.75	0.50	1,985	100	203,416	101
Yaculta Rapids	50.38	-125.15	10	10	4.38	7.78	539	20	12,135	94
Arran Rapids	50.42	-125.14	14	10	5.25	13.45	271	22	6,629	89
Secheldt Rapids 2	49.74	-123.90	14.5	16	6.67	27.60	261	8	2,739	76
Gillard Passage 1	50.39	-125.16	13	10	5.03	11.84	237	16	4,393	52
Scott Channel	50.79	-128.50	3	3	1.31	0.21	9,970	22	244,256	51
Active Pass	48.86	-123.33	8	8	3.50	3.98	561	20	12,628	50
Nahwitti Bar 1	50.89	-127.99	5.5	5.5	2.41	1.29	2,993	9	34,417	45
Race Passage	48.31	-123.54	6	7	2.84	2.14	884	20	19,885	42
Green Pt 2	50.45	-125.52	6	6	2.63	1.68	538	35	20,157	34
Blackney Passage	50.57	-126.69	5	5	2.19	0.97	814	40	34,598	34
GreenPt Rap. 1	50.44	-125.51	7	7	3.06	2.67	440	25	12,093	32
Porlier Pass	49.01	-123.59	9	8	3.72	4.78	339	15	5,926	28
Becher Bay	48.32	-123.62	3	3	1.31	0.21	2,148	60	134,263	28
Upper rapids 2	50.31	-125.23	9	9	3.94	5.67	242	18	4,955	28
Gillard Passage 2	50.40	-125.15	10	8	3.94	5.67	393	10	4,916	28
Whirlpool Rapids	50.46	-125.76	7	7	3.06	2.67	321	28	9,804	26
Surge Narrows	50.23	-125.16	6	6	2.63	1.68	413	30	13,432	23
Chatham Islands	48.45	-123.26	6	6	2.63	1.68	903	12	13,099	22
Quatsino Narrows	50.55	-127.56	9	8	3.72	4.78	207	18	4,240	20
Hole-in-the-Wall 1	50.30	-125.21	12	9.5	4.70	9.67	189	8	1,985	19
Village Island	50.64	-126.51	3	3	1.31	0.21	1,234	70	89,461	19
Green Pt 3	50.44	-125.57	5	5	2.19	0.97	673	25	18,498	18
Nahwitti Bar 2	50.87	-127.99	5.5	5.5	2.41	1.29	2,012	4	13,078	17
First Narrows	49.32	-123.14	6	6	2.63	1.68	418	16	7,734	13
Buckholtz Ch 2	50.49	-127.60	3	3	1.31	0.21	1,073	50	56,329	12
Buckholtz Ch 1	50.49	-127.67	3	3	1.31	0.21	997	50	52,357	11
Tallac - Erasmus Is	50.44	-125.47	3	3	1.31	0.21	665	75	51,522	11
Lower Rapids 1	50.31	-125.26	7	7	3.06	2.67	371	8	3,891	10
Picton Point	50.46	-125.40	3	3	1.31	0.21	881	50	46,235	10
Charles Bay Rapids	50.42	-125.49	5	5	2.19	0.97	664	12	9,631	9
Pearse Passage	50.58	-126.90	4	4	1.75	0.50	1,168	13	18,104	9
Welcome Passage	49.51	-123.97	3	3	1.31	0.21	746	50	39,189	8
Alert Bay	50.57	-126.93	3	3	1.31	0.21	1,771	18	36,311	8
Gabriola Pass.	49.13	-123.70	8.5	9	3.83	5.21	137	8	1,435	7

Site Name	Latitude	Longitude	Maximum Current Speed Flood	Maximum Current Speed Ebb	Mean Maximum Depth Average Current Speed	Mean Power Density	Width of Passage	Average Depth of Passage	Flow Cross-sectional Area	Mean Potential Power
	deg	deg	knot	m/s	m/s	kW/m^2	m	m	m^2	MW
Second Narrows	49.29	-123.02	6	6	2.63	1.68	254	14	4,159	7
Haddington Passage 2	50.59	-127.02	3	3	1.31	0.21	1,311	20	29,492	6
Moresby Passage	48.73	-123.34	3	3	1.31	0.21	1,191	20	26,793	6
Nitinat Narrows	48.67	-124.85	8	8	3.50	3.98	61	20	1,376	5
Stuart Narrows	50.90	-126.94	6	7	2.84	2.14	261	7	2,478	5
Hamber Island	49.32	-122.94	4	4	1.75	0.50	414	23	10,362	5
Dodds Narrows	49.14	-123.82	9	8	3.72	4.78	91	9	1,047	5
Sansum Narrows	48.78	-123.56	3	3	1.31	0.21	553	40	23,509	5
Gillard Passage 3	50.39	-125.16	10	8	3.94	5.67	92	5	686	4
Haddington Passage 1	50.61	-127.02	3	3	1.31	0.21	570	25	15,684	3
Matlset Narrowsq	49.24	-125.80	4	4	1.75	0.50	464	10	5,799	3
Tsownin Narrows	49.78	-126.65	3	3	1.31	0.21	283	45	13,460	3
Hayden Passage	49.40	-126.11	4	4	1.75	0.50	312	15	5,457	3
N Sydney Is	48.67	-123.35	3	3	1.31	0.21	1,029	9	11,833	2
Scouler Pass	50.31	-127.82	4	4	1.75	0.50	512	4	3,327	2
Dawley Passage	49.15	-125.79	3	3	1.31	0.21	289	20	6,509	1
Neilson Is - Morpheus	49.16	-125.88	5	5	2.19	0.97	202	4	1,311	1
Tsapee Narrows	49.12	-125.82	4	4	1.75	0.50	280	7	2,517	1
Felice Is - Grice Pt	49.15	-125.91	3	3	1.31	0.21	339	12	4,915	1
									Total:	3,580

Table 12. Tidal current power sites in southern British Columbia.

Site Name	Latitude	Longitude	Maximum Current Speed Flood	Maximum Current Speed Ebb	Mean Maximum Depth Average Current Speed	Mean Power Density	Width of Passage	Average Depth of Passage	Flow Cross-sectional Area	Mean Potential Power
	deg	deg	knot	m/s	m/s	kW/m^2	m	m	m^2	MW
Nakwakto Rapids	51.10	-127.50	14	16	6.56	29.06	434	10	5,643	164
Otter Passage	53.00	-129.73	6	6	2.63	1.86	620	50	32,860	61
Beaver Passage	53.73	-130.37	4	4	1.75	0.55	810	100	83,430	46
Outer Narrows	51.09	-127.63	7	10	3.72	5.29	210	17	4,206	22
Perceval Narrows	52.33	-128.38	5	5	2.19	1.08	382	25	10,709	12
Hiekish Narrows	52.88	-128.49	4	4.5	1.86	0.66	571	25	16,000	11
Draney Narrows`	51.47	-127.56	9	9	3.94	6.28	139	8	1,463	9
Kildidt Narrows	51.89	-128.11	12	12	5.25	14.88	75	2	375	6
Hidden Inlet	54.95	-130.33	9	9	3.94	6.28	142	3	781	5
Porcher Narrows	53.90	-130.47	7	7	3.06	2.95	120	10	1,560	5
Freeman Passage	53.85	-130.58	4	4	1.75	0.55	150	32	5,250	3
Tuck Narrows	54.40	-130.26	6	6	2.63	1.86	138	7	1,379	3
Eclipse Narrows	51.09	-126.77	6	5	2.41	1.43	141	6	1,269	2
Clement Rapids	53.20	-129.04	6	6	2.63	1.86	80	7	800	1
Schooner Channel	51.06	-127.52	6	6.5	2.73	2.10	72	6	648	1
Hawkins Narrows	53.41	-129.42	8	8	3.50	4.41	55	3	301	1
Higgins Passage 2	52.48	-128.71	5	5	2.19	1.08	173	3	1,039	1
Nelson Narrows 1	51.77	-127.43	3.5	3.5	1.53	0.37	313	6	2,817	1
Masset Sound	53.98	-132.00	5	5.5	2.30	1.25	750	20	17,250	21
Rose Spit	54.25	-131.52	2.5	2.5	1.09	0.13	11,000	8	121,000	16
Houston Stewart Channe	52.16	-131.12	5	5	2.19	1.08	610	17	12,200	13
Parry Passage	54.18	-133.00	5	3	1.75	0.55	594	28	18,414	10
Skidigate Entrance	53.36	-131.90	3	3	1.31	0.23	1,322	30	43,626	10
Fairbairn Channel	53.04	-131.68	3	3	1.31	0.23	710	25	19,880	5
Skuttle Passage	52.66	-131.68	2	3	1.09	0.13	510	45	24,480	3
Alexandra Narrows	54.05	-132.57	2	2.5	0.98	0.10	420	25	11,760	1
Tasu Narrows	52.74	-132.11	1.5	1.5	0.66	0.03	425	82	36,125	1
									Total:	434

Table 13. Tidal current power sites in northern British Columbia.

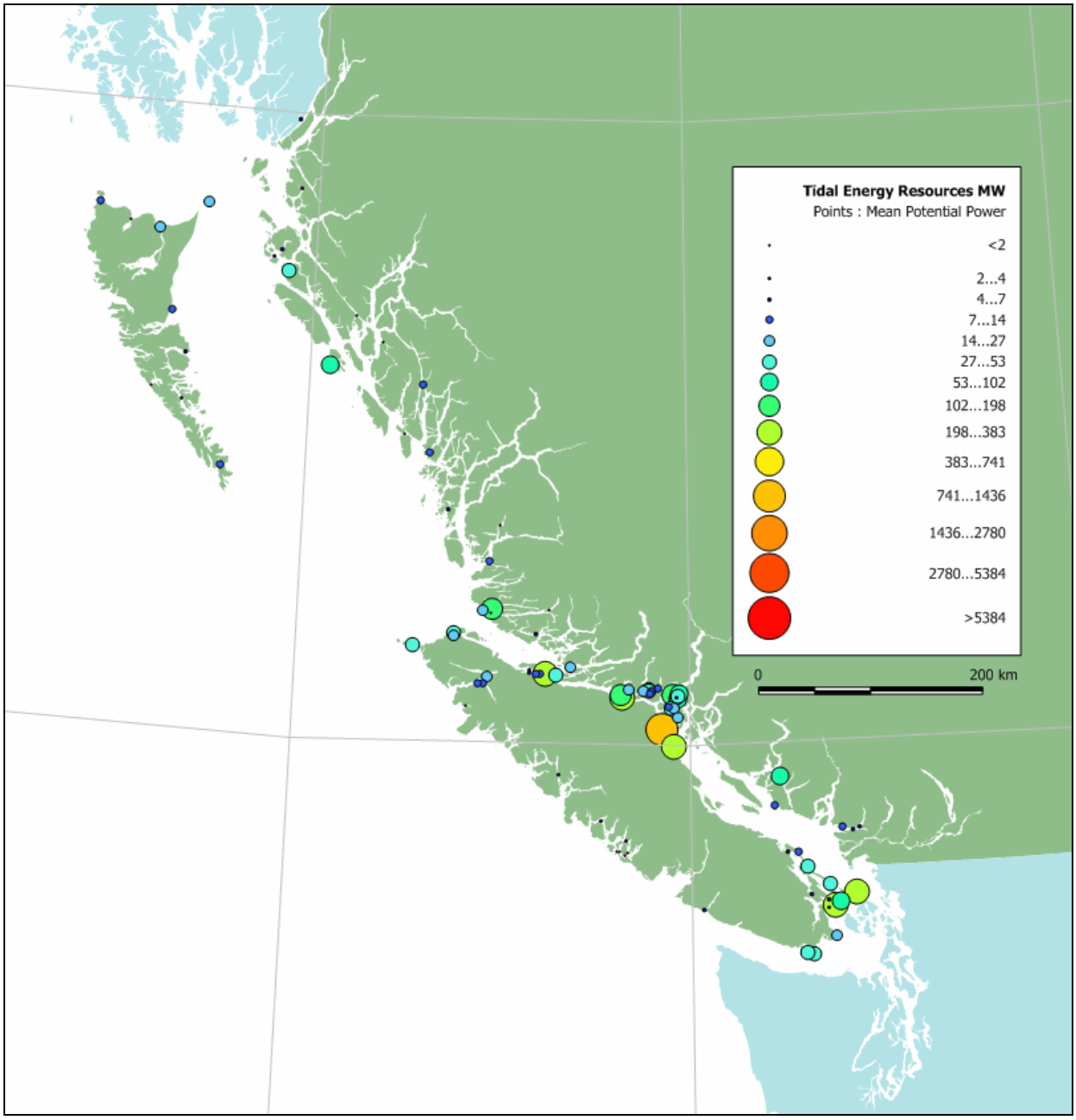


Figure 77. Leading tidal current power sites, Pacific coast.

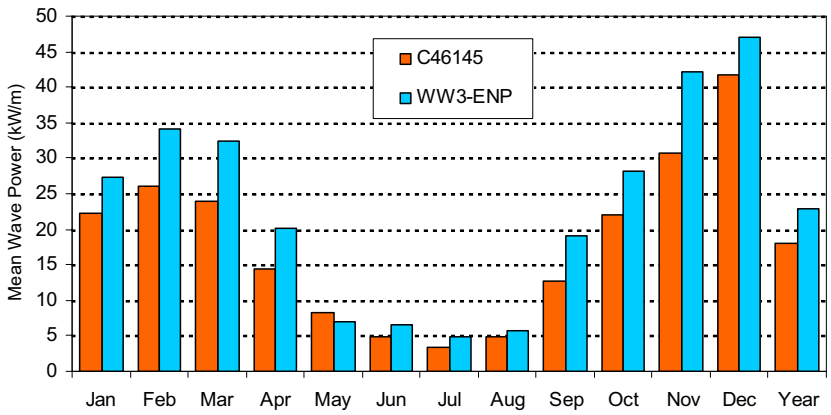


Figure 40. Comparison of mean monthly wave power from buoy measurements and WW3-ENP hindcast, station C46145.

3.7. Discussion of Results

Canadian electricity demand now totals roughly 580 TWh per year, or roughly 18 MWh annually per person. This is equivalent to a mean power of 66,165 MW or roughly 2 kW/person. The three leading electricity demand sectors are manufacturing (38%) residential (28%) and commercial and institutional (22%). Assuming that only 10% of the available wave power is converted into electrical energy, a 1 km wide site with a mean annual power of 25 kW per meter of wave crest could potentially generate 21.9 GWh per year, enough to supply the residential electrical needs of over 4,300 typical Canadians.

Wave energy resources in the NE Pacific are largest in the open ocean far from shore, and decrease as you cross the continental shelf and approach land. The annual mean wave energy flux for exposed deep-water sites located 100 km off Canada's Pacific coast is on the order of 40 to 45 kW/m. Approaching Vancouver Island from the west along the 49°N parallel, the mean annual wave power decreases from ~43 kW/m 150 km offshore, to ~39 kW/m 75 km offshore, to ~25 kW/m at the coast. Moving east along the 53°N parallel, the mean annual wave power decreases from ~44 kW/m 100 km offshore to ~36 kW/m at the western shore of the Queen Charlotte Islands. Wave energy resources in the northeast Pacific also feature a strong seasonal variability – the mean wave energy flux in winter (December to Februrary) is typically around six to eight times larger than in summer (June to August).

Meanwhile, the annual mean wave power at exposed deep-water sites near the edge of the continental shelf in the northwest Atlantic varies from around 21 kW/m off southern Nova Scotia to around 50 kW/m on the edge of the Grand Banks east of Newfoundland. The continental shelf in the northwest Atlantic is much wider than in the northeast Pacific, and there is generally more attenuation of wave energy across the shelf, so that the wave energy resources close to shore are often significantly smaller than at the shelf edge. For example, on a line projected across the Scotian Shelf southeast from Halifax, the mean annual wave energy increases from ~9 kW/m at the coast, to ~20 kW/m roughly 200 km offshore, and to ~30 kW/m roughly 400 km offshore. Wave energy resources in the northwest Atlantic also feature a strong seasonal variability – the mean wave energy flux in summer is typically around one-third of the annual value. In eastern

Canada, the richest wave energy resources close to land lie near the southeastern tip of Newfoundland and around Sable Island. The mean annual wave power in these nearshore regions is on the order of 25 kW/m.

By comparison, the mean annual wave energy at exposed deep-water locations off the western coast of Europe varies between ~25 kW/m near the Canary Islands, up to ~75 kW/m off Ireland and Scotland (Pontes, 1998). The European resource is also seasonally variable: the mean wave power in summer is typically between 25% to 50% of the annual value. The European resource also decreases as you approach shore. For example, Pontes et al. (2003) reports that the nearshore wave energy resource along the coast of Portugal varies between ~8 kW/m and ~25 kW/m, while the offshore resource is on the order of 39 kW/m.

The new results presented here are generally consistent with recent analyses of wave energy resources along the Atlantic and Pacific coasts of the U.S. performed by the Electrical Power Research Institute (EPRI, 2005). The EPRI studies indicate that the mean annual wave power at exposed deep-water sites off the coasts of Washington State and Maine are about 40 kW/m, and 25 kW/m, respectively.

The total mean annual wave power off Canada's Atlantic and Pacific coasts has been estimated by integrating the power density along the 1,000m isobath and along the outer edge of the 200-mile fishing zone. The results, summarized in Table 8, show that the mean wave power along the 1,000 m isobath off Canada's Pacific coast totals roughly 37,000 MW or over 55% of Canadian electricity consumption, while the mean waver power along the 1,000 m isobath off Canada's Atlantic coast sums to 146,500 MW, or more than double current electricity demand.

The waters off Canada's Pacific and Atlantic coasts are endowed with rich wave energy resources. The results presented here define the scale of these resources, as well as their significant spatial and seasonal variations. It is important to recognize that due to various factors including environmental considerations and losses associated with power conversion, only a fraction of the available wave energy resource can be extracted and converted into useful power. Even so, the Canadian resources are considered sufficient to justify further research into their development as an important source of renewable energy for the future.

This work has aimed to quantify and map Canadian offshore wave energy resources. As noted previously, the wave power along a coast (above the ~150 m depth contour) can vary considerably due to sheltering and bathymetric effects such as wave shoaling, refraction and diffraction. These processes will create pronounced local variations in wave conditions and energy potential close to shore, particularly in regions with complex bathymetry. Clearly, these important local variations are beyond the scope of the present analysis.

Further work is clearly required to improve the definition of Canada's nearshore wave energy resources. Shallow water wave transformation models can be applied to study and quantify nearshore wave conditions provided that the necessary high-resolution bathymetry data is available. A logical next step is to apply such models to extend the present results into selected nearshore regions. Further work is also planned to consider the directionality of the Canadian wave energy resources described herein, and to assess the implications of directionality on resource assessment and energy extraction.

Line of integration	from latitude deg	to Latitude deg	Length km	Mean annual wave power MW	Mean annual power density kW/m
Pacific Ocean					
200 mile limit	46.54	53.49	1,070	54,300	50.7
1,000m isobath	48.13	54.31	915	37,000	40.4
Atlantic Ocean					
200 mile limit	40.0	45.0	1,660	62,667	37.8
200 mile limit	45.0	50.0	590	27,616	46.8
200 mile limit	50.0	55.0	600	29,079	48.5
200 mile limit	55.0	60.0	680	29,196	42.9
200 mile limit	60.0	65.0	570	12,062	21.2
200 mile limit	65.0	70.0	590	1,334	2.3
200 mile limit	40.0	70.0	4,690	161,955	34.5
Atlantic Ocean					
1,000m isobath	41.1	45.0	1,840	61,897	33.6
1,000m isobath	45.0	50.0	800	36,603	45.8
1,000m isobath	50.0	55.0	660	24,955	37.8
1,000m isobath	55.0	60.0	760	16,024	21.1
1,000m isobath	60.0	64.1	540	7,047	13.0
1,000m isobath	41.1	64.1	4,600	146,525	31.9

Table 8. Summary of offshore wave energy resources near Canadian waters.

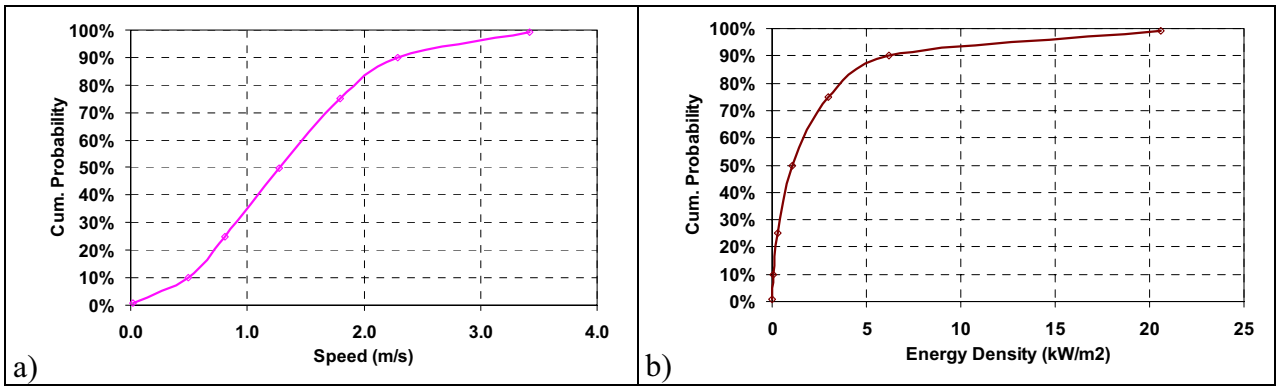


Figure 55. Cumulative distribution of a) depth averaged speed and b) depth averaged power density near Cape St. James.

4.3.3. Results

Selected results from the preceding analysis will be presented in what follows, arranged by ocean, starting with the Pacific.

Pacific Ocean

Figure 56 shows the mean tide range along the BC coast. The rms velocity of the tidal flows throughout the region, as predicted by the tidal models discussed above, is presented in Figure 57 to Figure 59. The mean power density of the tidal flows is plotted in Figure 60 to Figure 62.

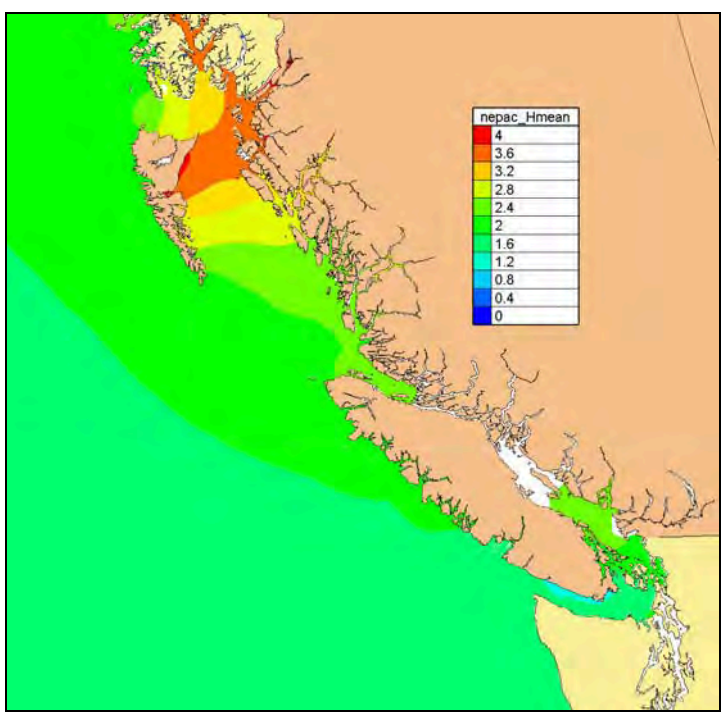


Figure 56. Mean tide range along the BC coast (m).

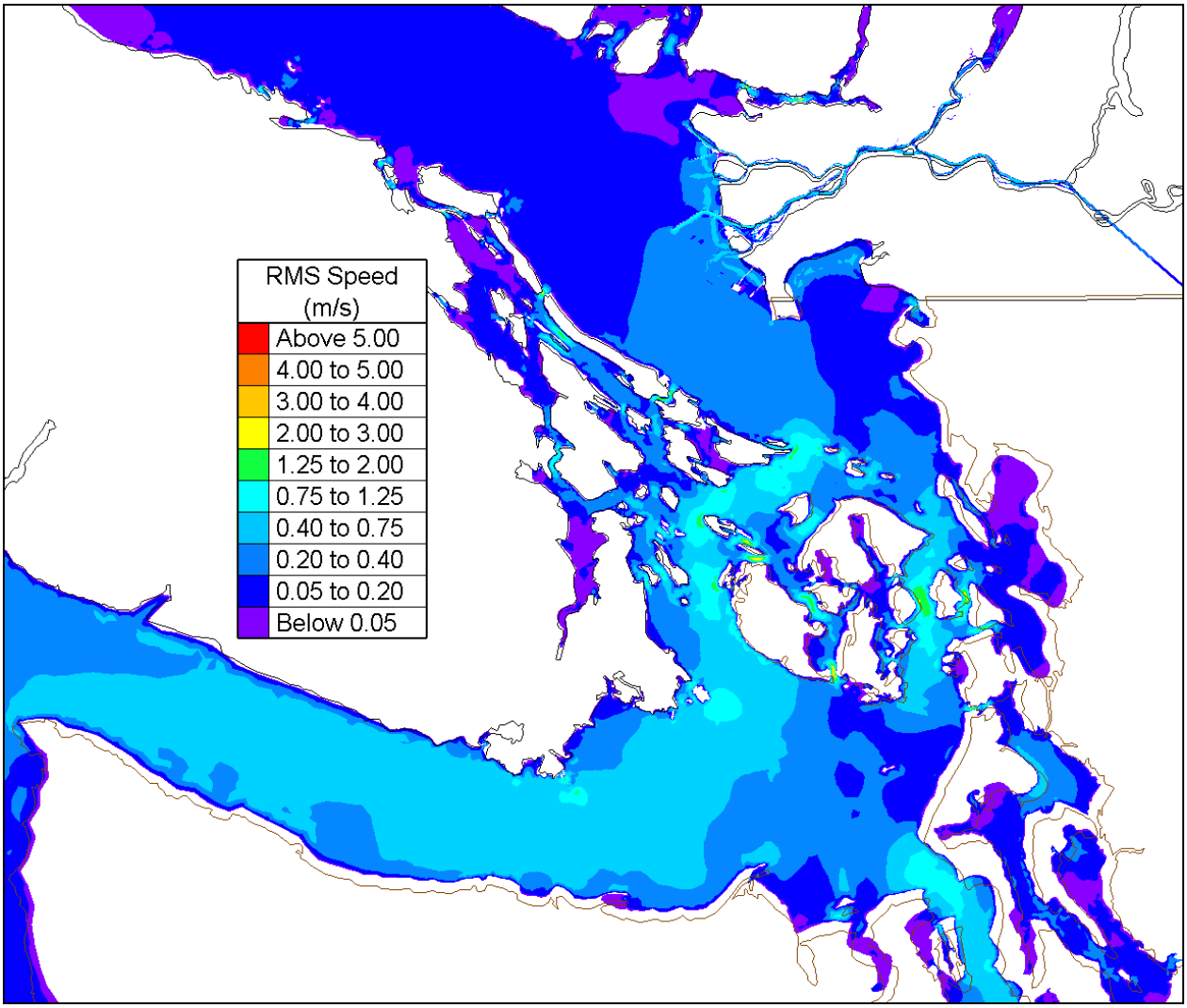


Figure 57. Root-mean-square tidal current speed, southern Vancouver Island.

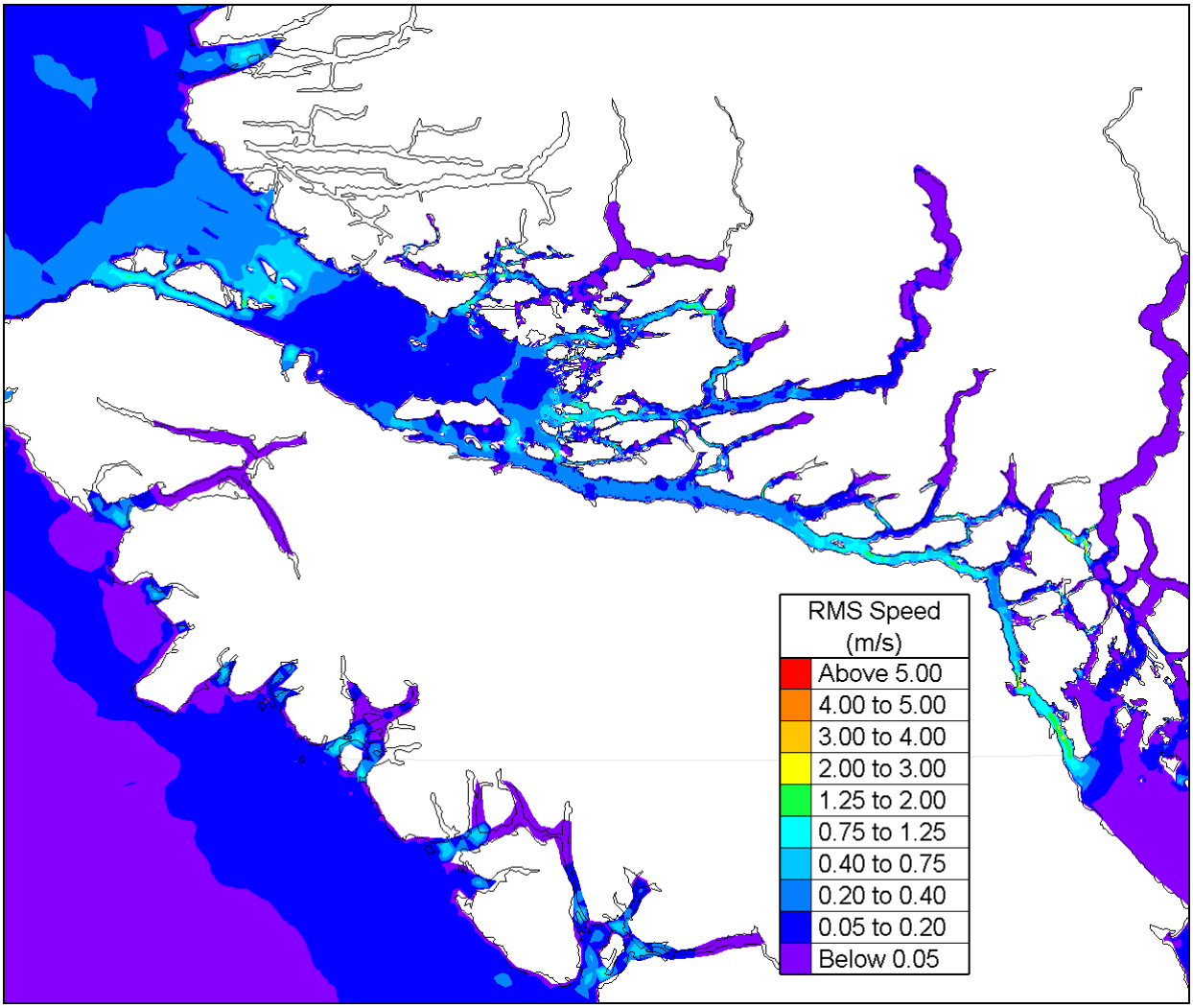


Figure 58. Root-mean-square tidal current speed, northern Vancouver Island.

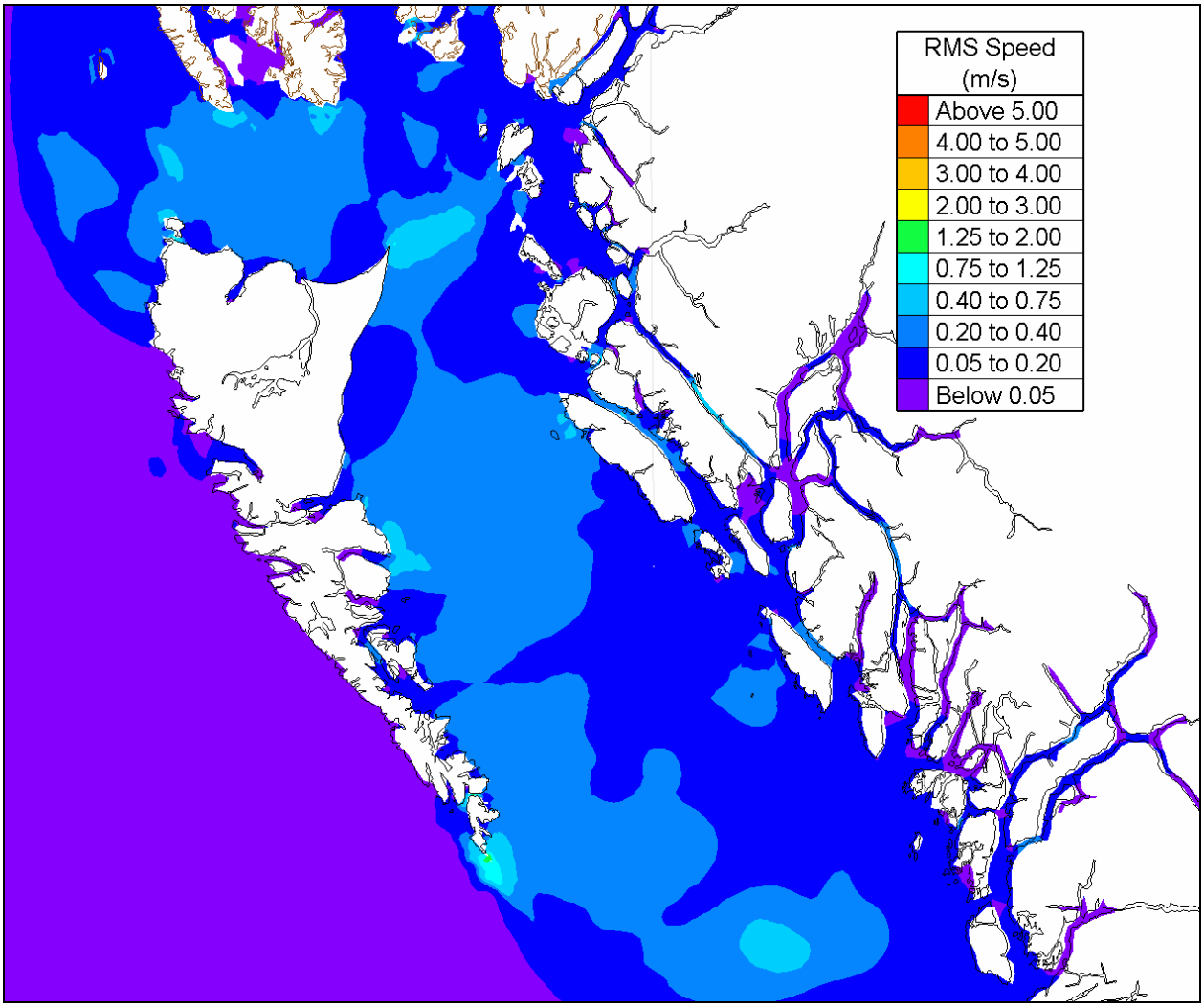


Figure 59. Root-mean-square tidal current speed, Queen Charlotte Islands.

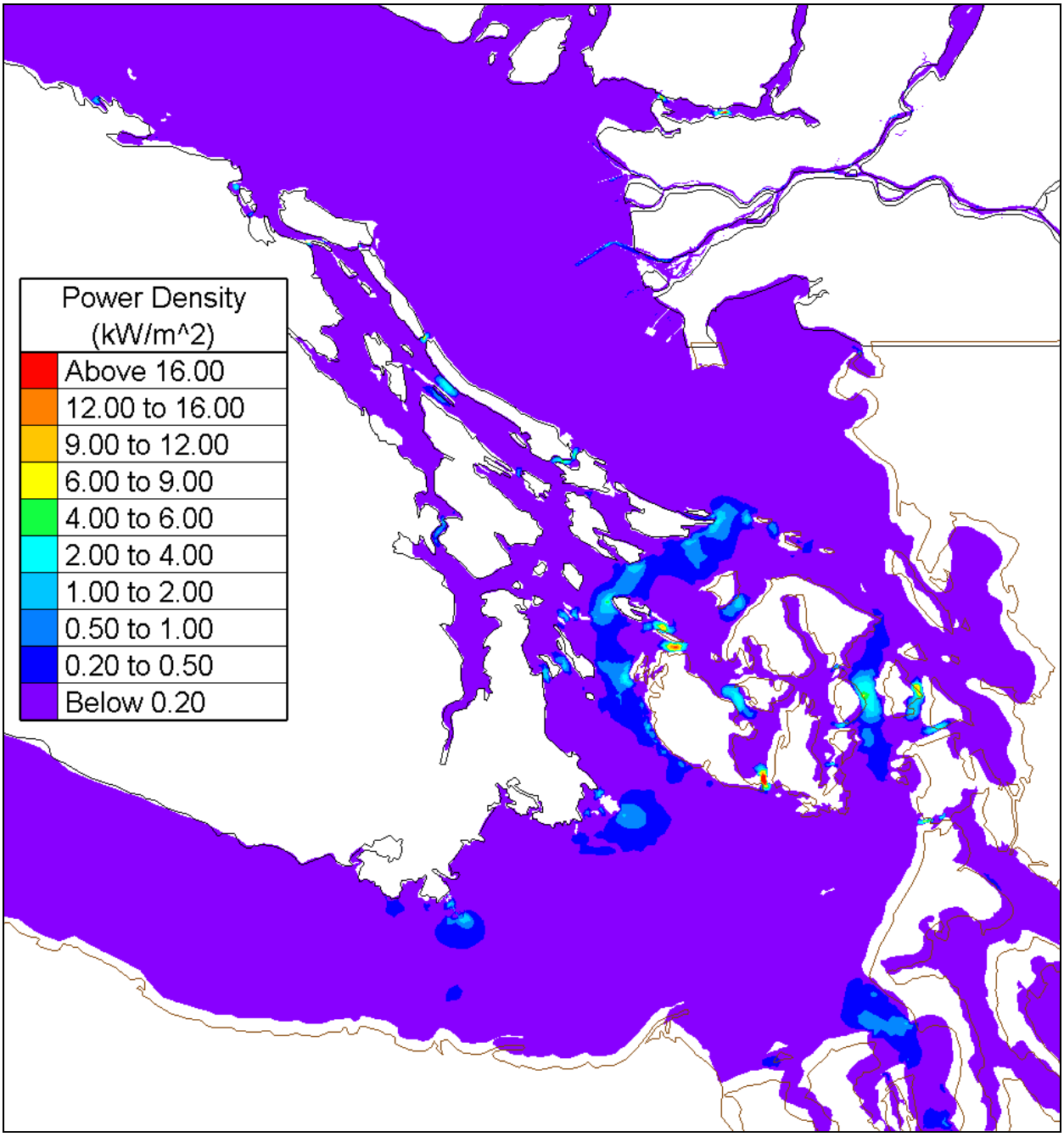


Figure 60. Mean power density, southern Vancouver Island.

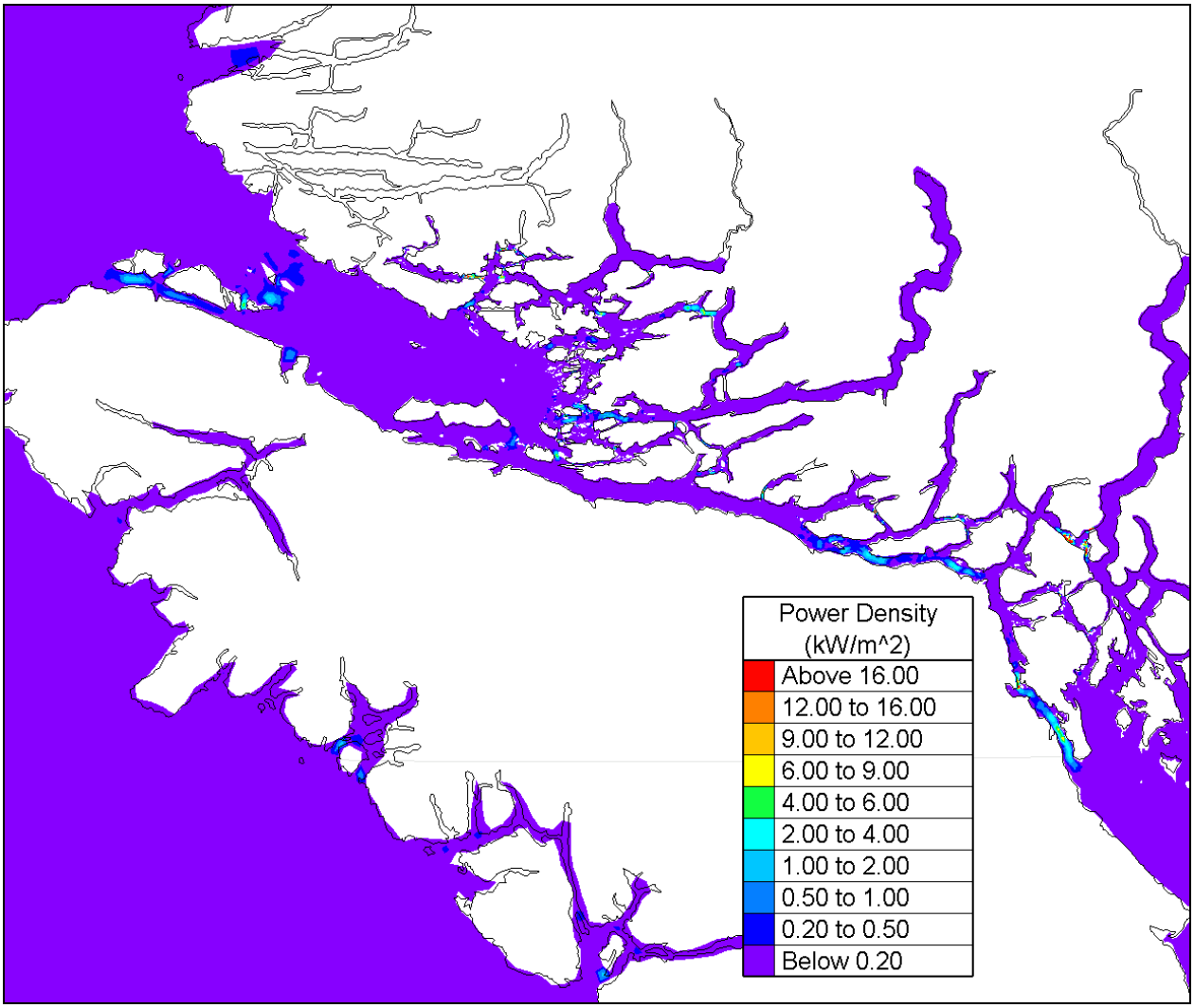


Figure 61. Mean power density, northern Vancouver Island.

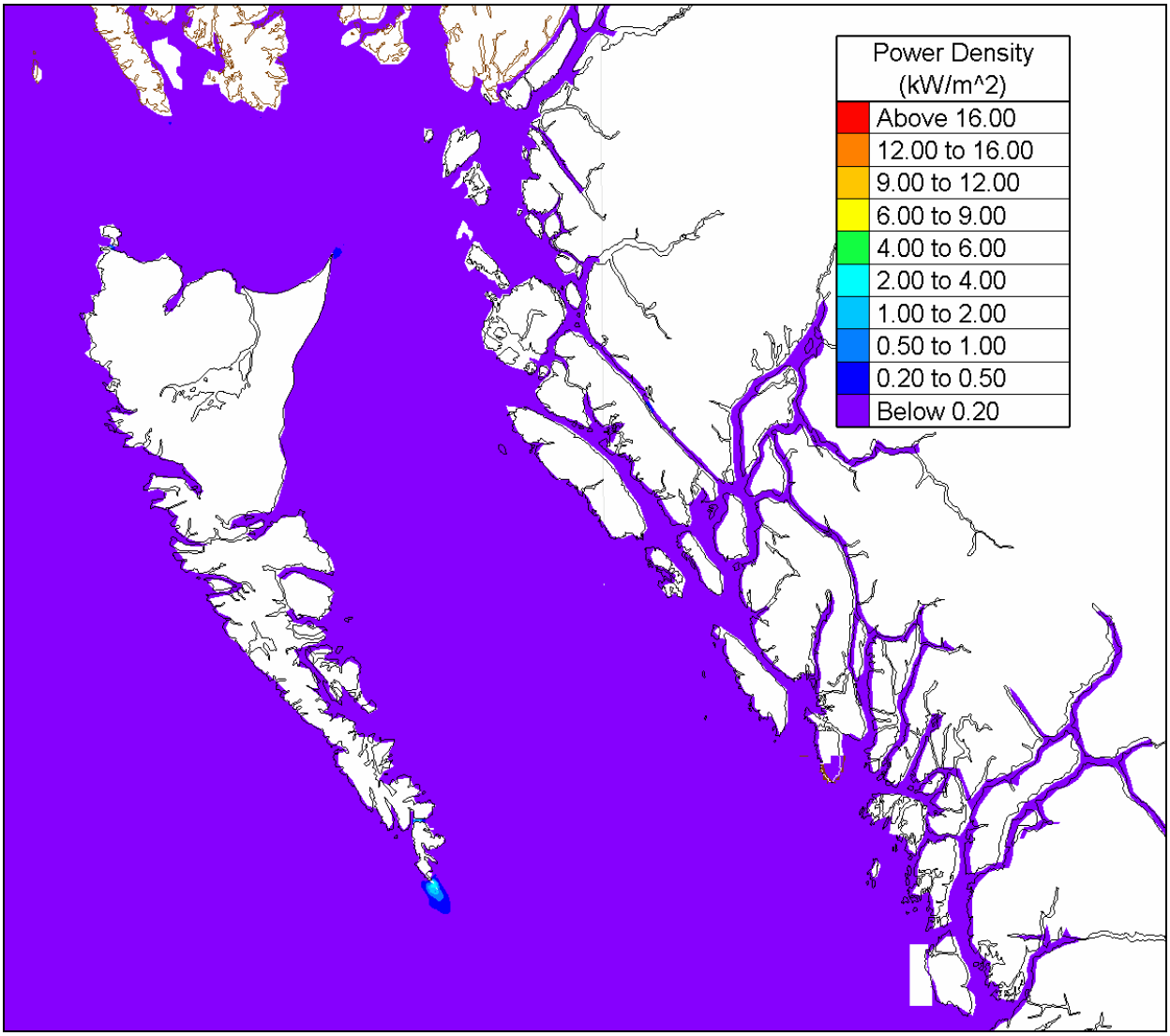


Figure 62. Mean power density, Queen Charlotte Islands.

4. SELECTED STUDY RESULTS

4.1 POTENTIAL TIDAL CURRENT ENERGY SUMMARY TABLES

Table 5 shows the estimated mean potential tidal current energy by Provinces in Canada for sites with a mean power greater than 1 MW.

Table 5: Canada Potential Tidal Current Energy by Province

Province	Potential Tidal Current Energy (MW)	Number of Sites (-)	Average Size (MW)
Northwest Territories	35	4	9
British Columbia	4,015	89	45
Quebec	4,288	16	268
Nunavut	30,567	34	899
New Brunswick	636	14	45
PEI	33	4	8
Nova Scotia	2,122	15	141
Newfoundland	544	15	36
TOTAL	**42,240**	**191**	**221**

Table 6 shows the distribution of mean potential power by Regions with Canada. Note that more than 80% of potential tidal current power is in regions presently impacted by winter ice conditions.

Table 6: Canada Potential Tidal Current Energy by Region

Region	Potential Tidal Current Energy (MW)
Vancouver Island Mainland	3,580
Pacific Mainland North	353
Queen Charlotte Islands	81
Arctic	1,008
Hudson Strait	29,595
Ungava	4,112
St. Lawrence River	153
Gulf of St Lawrence	537
Atlantic North	65
Atlantic South	30
Bay of Fundy	2,725
TOTAL	**42,240**

Table 7 shows the 50 largest potential tidal current power sites in Canada. Table 8 shows the 50 sites in Canada with the largest Mean Power Density (MW/m^2).

Table 7: Canada Tidal Current Power Sites (50 largest sites)

Region	Province	Site Name	Chart	Latitude	Longitude	Current Station	Max. Speed Flood (knots)	Max. Speed Ebb (knots)	Mean Max. Depth Ave. Speed (m/s)	Mean Power Density (kW/m2)	Passage Width (m)	Average Depth of Passage (m)	Flow Cross-sectional Area (m2)	Mean Potential Power (MW)
Hudson Strait	Nunavut	Mill Island-Salisbury Island	5450	63.81	-77.50		8	8		0.887	32054	204	6571070	10426
Hudson Strait	Nunavut	Mill Island-Baffin Island	5450	64.15	-77.57		8	8		1.020	26125	229	6008750	7584
Hudson Strait	Nunavut	Gray Strait	5456	60.54	-64.69		6	6	2.63	2.110	6000	550	3307800	6979
Hudson Strait	Nunavut	Nottingham Island-Ungava	5450	62.83	-77.93		8	8		0.136	64098	228	14678442	1972
Bay of Fundy	Nova Scotia	Minas Basin	4010	45.35	-64.40		7.5	7.5	3.28	6.036	4376	56	274113	1903
Hudson Strait	Nunavut	Salisbury Island-Nottingham Island	5450	63.45	-77.41		8	8		0.360	22146	147	3277608	1704
Ungava	Quebec	Smoky Narrows	5468	58.92	-69.27		12	12	5.25	16.880	1500	55	92400	1560
Ungava	Quebec	Algernine Narrows	5468	58.79	-69.60		10	10	4.38	9.768	2000	59	130400	1274
Vancouver Island Mainland	British Columbia	Seymour Narrows	353902	50.13	-125.35	5000	16	14	6.56	18.160	769	41	33331	786
Hudson Strait	Nunavut	Lacy/Lawson Islands	5456	60.60	-64.62		7	7	3.06	3.351	2750	80	223575	749
Ungava	Quebec	Riviere George Entrance	5335	58.76	-66.12		8	8	3.50	5.001	3000	35	125100	626
Gulf of St Lawrence	Newfoundland	Strait of Belle Isle	4020	51.45	-56.68					0.201	26069	49	1298236	373
Vancouver Island Mainland	British Columbia	N. Boundary Passage	346201	48.79	-123.01		4	4	1.75	0.498	5158	140	734949	366
Vancouver Island Mainland	British Columbia	Discovery Pass. S.	353901	50.00	-125.21		7	7	3.06	3.676	1459	42	65626	327
Arctic	Nunavut	Labrador Narrows	7487	69.71	-82.59		6	6	2.63	2.110	1500	100	151950	321
Vancouver Island Mainland	British Columbia	Boundary passage	344101	48.69	-123.27		3.5	3.5	1.53	0.334	4472	175	793760	265
Ungava	Quebec	Riviere Arnaud (Payne) Entrance	5352	59.98	-69.84		9	9	3.94	7.121	2300	9	32200	229
Bay of Fundy	New Brunswick	Clarks Ground	4340	44.59	-66.64		6	6	2.63	2.110	4092	22	102300	216
Vancouver Island Mainland	British Columbia	Current Passage 2	354401	50.39	-125.86		6	6	2.63	1.681	1502	80	123931	208
Vancouver Island Mainland	British Columbia	Weyton Passage	354601	50.59	-126.82		6	6	2.63	1.681	1535	75	118985	200
Ungava	Quebec	Koksoak Entrance	5376	58.52	-68.17		6	6	2.63	2.110	2000	40	92400	195
Hudson Strait	Nunavut	Cape Enouolik	7065	64.95	-78.33		5	5	2.19	1.221	5000	25	142500	174

Region	Province	Site Name	Chart	Latitude	Longitude	Current Station	Max. Speed Flood (knots)	Max. Speed Ebb (knots)	Mean Max. Depth Ave. Speed (m/s)	Mean Power Density (kW/m2)	Passage Width (m)	Average Depth of Passage (m)	Flow Cross-sectional Area (m2)	Mean Potential Power (MW)
Pacific Mainland North	British Columbia	Nakwakto Rapids	355001	51.10	-127.50	6700	14	16	6.56	29.062	434	10	5643	164
Vancouver Island Mainland	British Columbia	Current Passage 1	354401	50.41	-125.87		5	5	2.19	0.973	1398	100	143331	139
Vancouver Island Mainland	British Columbia	Dent Rapids	354301	50.41	-125.21	5530	11	8	4.16	6.672	420	45	19955	133
Vancouver Island Mainland	British Columbia	South Pender Is	344101	48.72	-123.19		4	4	1.75	0.498	1985	100	203416	101
Bay of Fundy	New Brunswick	Devils Half Acre	4340	44.54	-66.69		6	6	2.63	2.110	2133	18	44793	95
Vancouver Island Mainland	British Columbia	Yaculta Rapids	354301	50.38	-125.15		10	10	4.38	7.782	539	20	12135	94
St. Lawrence River	Quebec	Passage de Ile aux Coudre	1233	47.43	-70.43		5	6	2.41	1.625	1700	30	56100	91
Vancouver Island Mainland	British Columbia	Arran Rapids	354301	50.42	-125.14	5600	14	10	5.25	13.447	271	22	6629	89
Ungava	Quebec	Nakertok Narrows	5352	60.00	-70.27		9	9	3.94	7.121	1100	6	12100	86
Bay of Fundy	New Brunswick	Old Sow	4114	44.92	-66.99		6	6	2.63	2.110	625	60	39375	83
Arctic	Nunavut	Bellot Strait	7752	72.00	-94.48		8	8	3.50	5.001	1000	16	16400	82
Arctic	Nunavut	Cache Pt Channel	7710	68.62	-113.55		5	5	2.19	1.221	6000	10	62400	76
Vancouver Island Mainland	British Columbia	Secheldt Rapids 2	351403	49.74	-123.90	9999	14.5	16	6.67	27.599	261	8	2739	76
Arctic	Nunavut	James Ross Strait	7083	66.69	-95.87		5	5	2.19	1.221	5900	10	61360	75
Bay of Fundy	New Brunswick	Head Harbour Passage 1	4114	44.95	-66.93		5	5	2.19	1.221	890	65	60520	74
Bay of Fundy	Nova Scotia	Northwest Ledge	4118	44.30	-66.42		4	4	1.75	0.625	5334	18	117348	73
Ungava	Quebec	Mikitok Narrows	5352	60.00	-70.27		9	9	3.94	7.121	700	8	9590	68
Arctic	Nunavut	Egg Island	7735	68.55	-97.40		7	7	3.06	3.351	750	25	19050	64
Pacific Mainland North	British Columbia	Otter Passage	3742	53.00	-129.73	8535	6	6	2.63	1.860	620	50	32860	61
Vancouver Island Mainland	British Columbia	Gillard Passage 1	354301	50.39	-125.16	5500	13	10	5.03	11.835	237	16	4393	52
Vancouver Island Mainland	British Columbia	Scott Channel	362501	50.79	-128.50		3	3	1.31	0.210	9970	22	244256	51
Vancouver Island Mainland	British Columbia	Active Pass	344201	48.86	-123.33	3000	8	8	3.50	3.984	561	20	12628	50
Bay of Fundy	New	Gran Manan Channel	4340	44.78	-66.86		2.5	2	0.98	0.111	5446	80	452018	50

Region	Province	Site Name	Chart	Latitude	Longitude	Current Station	Max. Speed Flood (knots)	Max. Speed Ebb (knots)	Mean Max. Depth Ave. Speed (m/s)	Mean Power Density (kW/m2)	Passage Width (m)	Average Depth of Passage (m)	Flow Cross-sectional Area (m2)	Mean Potential Power (MW)
	Brunswick													
Arctic	Nunavut	Seahorse Point	7065	63.83	-80.13		5	5	2.19	1.221	2000	20	40800	50
Bay of Fundy	Nova Scotia	The Hospital	4242	43.44	-66.00		4	4	1.75	0.625	3600	18	79200	50
Gulf of St Lawrence	Newfoundland	Pointe Armour	4020	51.45	-56.86		4	5	1.97	0.890	1500	35	53700	48
Gulf of St Lawrence	Newfoundland	Forteau	4020	51.41	-56.95		4	5	1.97	0.890	1500	35	53700	48
Pacific Mainland North	British Columbia	Beaver Passage	3747	53.73	-130.37	8545	4	4	1.75	0.551	810	100	83430	46
Arctic	Nunavut	Nettilling Fiord	7051	66.72	-72.83		8	8	3.50	5.001	1700	5	9180	46
Vancouver Island Mainland	British Columbia	Nahwitti Bar 1	354901	50.89	-127.99		5.5	5.5	2.41	1.295	2993	9	34417	45
TOTAL														**40697**

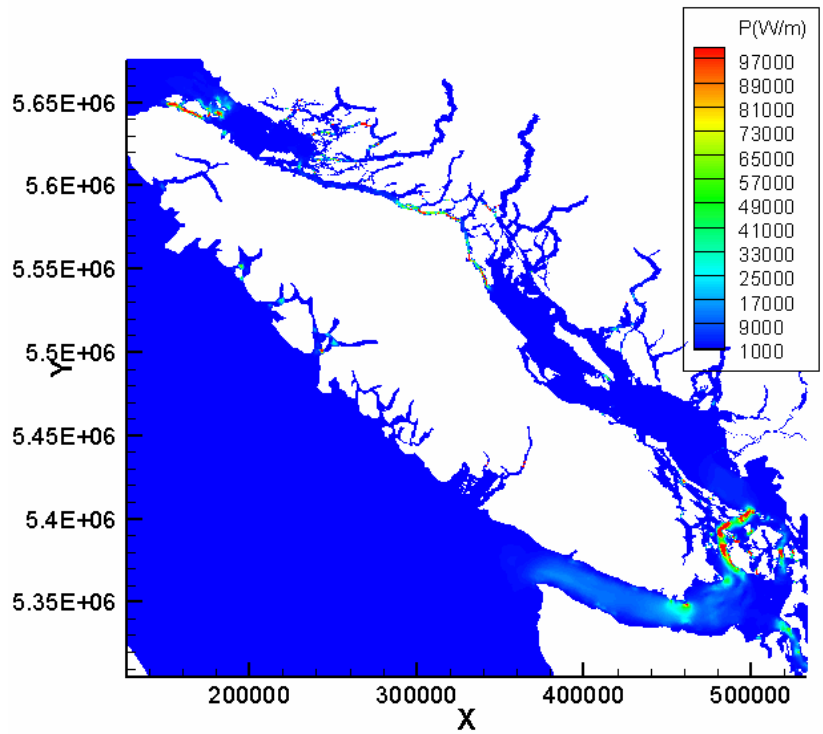
Notes:

1. The tidal current site data shown in yellow in Table 7 and Table 8 were derived from tidal model results (see Section 4.3 and Section 2.3.
2. Some of the tidal current sites shown in Table 7 and Table 8 are located in close proximity to each other in the same tidal channel or tidal inlet (e.g. Seymour Narrows/Discovery Passage in BC and Smoky Narrows and Algernine Narrows in Leaf Bay, Ungava, PQ). The total extractable power available from such adjacent sites will depend on the specific characteristics of the driving tidal dynamics, site geometry and the energy extraction technology used.

4.3 POTENTIAL TIDAL CURRENT ENERGY DENSITY MAPS

Figure 13 through Figure 16 show maps of power density in units W/m for the Pacific Coast, Hudson's Strait, Atlantic Coast and Bay of Fundy North respectively. The power density colour scales for all four maps are similar. These maps were developed from tidal model results.

Figure 13: Power Density - Pacific Coast



A Feasibility Study:

Tidal Power Generation for a Remote, Off-Grid Community on the British Columbia Coast

For

Janice Larson

British Columbia Ministry of Energy, Mines and Petroleum Resources

Prepared by

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February 21, 2007

Appendix I

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"Reflect on the motion of the waves, the flux and reflux, the ebb and flow of the tides. What is the ocean? An enormous force wasted. How stupid the earth is not to make use of the ocean." [2]

Victor Hugo, 1888

[1] Ma Destinee, painting by Victor Hugo, image source http://expositions.bnf.fr/hugo/grands/005.htm
[2] Victor Hugo, *Ninety-Three, Volume II*, translated from the French by Helen B. Dole, (New York: Thomas Y. Crowell & Co., 1888), p. 258

Executive Summary

Tidal power generation is about extracting clean power from a reliable and renewable energy source – the ocean. New technology is making ocean energy a viable source of power that, along with other forms of alternative energy, can supplant fossil fuels as the planet's dominant energy source.

This paper investigates the feasibility of developing a package solution using tidal power generation for a remote BC coastal community, Stuart Island. This study was conducted for Royal Roads University as part of the requirements for a Master of Business Administration degree and for the BC Ministry of Energy, Mines and Petroleum Resources.

Stuart Island is not on the power grid, and because of the high cost of connection to the grid, it is unlikely to be connected in the near future. Presently, diesel generators supply all power on the island. Stuart Island is adjacent to some of the best potential sites for tidal power generation on the BC coast. The existing situation in the Stuart Island area is examined in the paper, followed by a discussion of alternative energy and power generation in remote off-grid locations and how these things relate to Stuart Island.

Secondary research was conducted into ocean energy in BC. This paper reviews government agencies and non-governmental organizations involved in ocean energy in BC, followed by a discussion of the active tidal power projects in the province. Stepping back a bit for a wider view, this paper reviews ocean energy activities, government agencies and programs and organizations across Canada. An even wider view is taken by examining international organizations involved in tidal energy generation and the tidal power activities in a number of countries around the world.

Turning the focus back on BC, the tidal resource potential along the coast of the province is investigated. Primary research then concentrates on the resources near Stuart Island, which are examined and to determine suitability.

The paper describes the available tidal power technologies, including the progress of the technology developers towards commercialization. Installation methods and challenges are

discussed, followed by a discussion of energy storage methods and their significance to off-grid applications.

The financial analysis compares the costs of diesel and tidal power generation. The investigation reveals that there is too much uncertainty to estimate the cost of the supply and installation of a tidal power generation device at Stuart Island at this time. A discussion of feasibility looks at the triple bottom line, and concludes with a discussion of the technological uncertainties.

The paper discusses how tidal energy development in BC can progress to meet the needs of remote communities in BC, with an eye to future export possibilities. The report concludes with a number of recommendations for the Ministry of Energy, Mines and Petroleum Resources to assist the tidal energy industry to move forward in BC.

Appendix I

Introduction

Imagine a remote island on the coast of British Columbia. On this Island there are a few resorts where people can enjoy terrific salmon fishing in a spectacular wilderness setting. Ecotourism thrives, with opportunities for visitors to see eagles, grizzly bears and orcas in their natural environment.

Unfortunately this vision is marred by the sight and sound of the numerous diesel generators that provide electrical power to the resorts and residents. These generators make it possible for the resorts to exist, and therefore for people to visit the area. But there is a price to be paid for this power. The financial price is high and possibly increasing if the price of diesel fuel climbs higher. The price to be paid also includes other, non-monetary costs – air pollution, noise pollution and the threat of water pollution from diesel spills during storage or transportation.

Now picture this place with the power provided by clean energy extracted from the ocean currents. Imagine clean, reliable power coming from a turbine far beneath the waves, blades silently turning in the powerful tidal stream. There is no smell of diesel exhaust to mask the pristine fragrance of the evergreen forest in the salty ocean breeze. No diesel engine noise to compete with the cries of the seagulls or the waves breaking on the rocks.

Wouldn’t it be wonderful if the second vision could be made real? Is it possible? Is it feasible? These are questions this study will endeavor to answer.

Stuart Island

This place is real - it is called Stuart Island. It is located on the BC coast about two hundred kilometers northwest of Vancouver. The area includes the islands and mainland surrounding Cardero Channel. The waters around Stuart Island boast powerful tidal currents, among the strongest in Canada.

In the winter, it is a quiet place in human terms, with only a few permanent residents and resort caretakers living there. Mother Nature, however, can be noisy with howling winds and crashing waves. Summertime is a different story, with the resorts full of guests and the air punctuated with the excited cries of the fishermen hooking into Spring Salmon. Through it all, the ocean

currents are constant, flooding and ebbing in their eternal cycle. The currents are strong here because the tidal flow on the east side of Vancouver Island is constricted in a few relatively narrow channels by the many islands between Johnson and Georgia Straits. The same conditions that make Stuart Island an ideal place for salmon and orcas make it an ideal place for tidal power generation.

Sustainability

What is sustainability, besides one of the most overused words in the English language? Merriam-Webster defines sustainable as relating to a method of harvesting or using a resource so that the resource is not depleted or permanently damaged.[3] Given that diesel fuel is an oil derivative - a non-renewable resource - its use as a power source for Stuart Island is not sustainable over the long term. In fact, the Society of Petroleum Engineers estimates the world's remaining oil reserves will last as little as 44.6 years at 2003 consumption levels.[4] While it is true that more reserves may well be discovered and so the world will not run out of oil in two generations, it is clear that alternative energy sources will be needed.

[3] Merriam-Webster's Online Dictionary, http://www.m-w.com/dictionary/sustainability , accessed December 2006
[4] Society of Petroleum Engineers, "How Much Oil and Natural Gas is Left?," Society of Petroleum Engineers website http://www.spe.org/spe/jsp/basic/0,,1104_1008218_1109511,00.html accessed December 2006

The British Columbia Ministry of Energy, Mines and Petroleum Resources

The client for the study is the BC Ministry of Energy, Mines and Petroleum Resources (MEMPR). The primary contact is Janice Larson, Director of the Bioenergy and Renewables Branch.

MEMPR is the lead agency in BC for alternative energy promotion and development and has taken an active role in establishing a strategic direction for the province. In 2005, the MEMPR published *Alternative Energy and Power Technology: A Strategy for BC*. This document describes a ten year vision to make the province a world leader in alternative energy and power technology.[5]

This view is endorsed by the Premier's Technology Council, which has concluded that export revenue and jobs in BC can be substantially increased by deploying power technology solutions in BC and then selling them abroad.[6] As Premier Gordon Campbell says, "BC has the people and the resources to help drive the global shift toward alternative energy and power technology as part of our goal of leading the world in sustainable environmental management. Innovative power technology developed here in BC is improving the quality of life for people around the world, by improving how power is generated, delivered and used. Demand for that expertise will only continue to grow."[7]

One of the market opportunities identified by the Council is remote power solutions for rural communities. In particular, an area of interest is investigating the use of alternate energy generation to meet the power requirements of remote BC communities.

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[5] BC Ministry of Energy, Mines and Petroleum Resources, "Alternative Energy and Power Technology: A Strategy for BC," BC Ministry of Energy, Mines and Petroleum Resources website, http://www.gov.bc.ca/empr/down/alternative_energy_task_force_strategy_final_april_5_05.pdf, accessed January 2007
[6] Ibid.
[7] Ibid.

Present Situation at Stuart Island

The area referred to as Stuart Island in this study refers to land surrounding the portion of Cardero Channel bounded by Sonora Island on the west, Dent Island to the northwest, the Mainland on the north and Stuart island on the east. Of course, it is the water between those islands that is most important to this study. Of particular interest are Gillard Passage, Barber Passage, Innes Passage and Yaculta Rapids.

[8]

There is no electrical service in the Stuart Island area as the nearest connection to the electrical grid is about 20 kilometres away. Because of this, all of the electrical power in the area is generated by diesel generators (commonly called gensets). Being forced to use diesel gensets has several consequences for the residents and businesses of the area. The largest factor is the cost of diesel fuel, which must be barged in monthly. Other factors include the necessity of fuel storage tanks, noise pollution and diesel exhaust emissions.

There are twelve permanent residences in the area that are occupied year round. In addition to these residences are several seasonal residences that are typically occupied in the summer. A small community centre with public dock, postal outlet and small general store is located in Big Bay. The community centre and Post Office is run by the Stuart Island Community Association.

[8] Image source: Google Earth, http://earth.google.com/

There are several resorts located in the area, most on Stuart Island, one on Sonora Island, one on Little Dent Island and a couple on the mainland. Some of the resorts are public and are open to guests in the summer season. Others are private facilities and are used by the companies that own them to accommodate customers and associates of the company. The resorts range in size and can accommodate from a dozen guests to more than one hundred. The map below illustrates the layout of the area and the location of the resorts and residences.

[9]

[9] Map drawn and provided by Jode Morgan, Morgan's Landing Lodge, http://morganslanding.bc.ca/

Appendix I

Every residence and resort generates its own power, and so every one has its own genset. The size and number of gensets varies by the size, and therefore the power requirement, of the facility. Resorts typically have more than one genset so that backup power is available in the event of an equipment failure. Often the gensets have different generating capacity so varying load conditions can be efficiently supplied. In addition to diesel power generation, most residents and resorts also use propane for cooking and as an alternate lighting or heating source.

Residents and resort operators are well aware of the powerful tidal currents in the Stuart Island area and are also aware of the concept of tidal power generation. Responses to enquiries during the preparation of this study were unanimously favourable to the possibility of using tidal energy to generate power for the area.

Appendix I

Alternative Energy

Alternative energy is a somewhat misleading term. In contemporary usage, it means energy that is produced by methods other than the burning of fossil fuels, large hydroelectric or nuclear power. However, long before these power generation methods were being used, people were harnessing "alternative" energy. People have harnessed wind and water power for millennia. The first windmill may have been used in Babylon about 4,000 years ago.[10] Waterwheels have also been in use since ancient times. Alternative energy has predated the modern conventional forms of power generation by thousands of years.

Nowadays, the term alternative energy refers to a number of distinct technologies:

- Wind
- Solar – photovoltaic
- Geothermal
- Biofuels / bioenergy
- Microhydro
- Ocean Energy
    - Wave
    - Tidal stream

Of the different technologies, small hydro and wind generation are the most widely used to date and are the most advanced. Wind power generation has achieved full commercialization and wind farms have become a familiar sight in many countries. A fully developed wind industry has been created and wind generated power is competitive with the cost of power generated by new conventional facilities such as hydro dams, coal-fired or nuclear plants. A National Energy Board report points out that "electricity rates do not reflect actual costs because they are based on historical costs and are, therefore, below the cost of developing new generation." [11] The following graph compares the cost ranges for emerging technologies compared with new conventional energy costs and heritage hydro costs. The graph on the next page clearly illustrates how alternative energy can be competitive with new conventional energy facilities.

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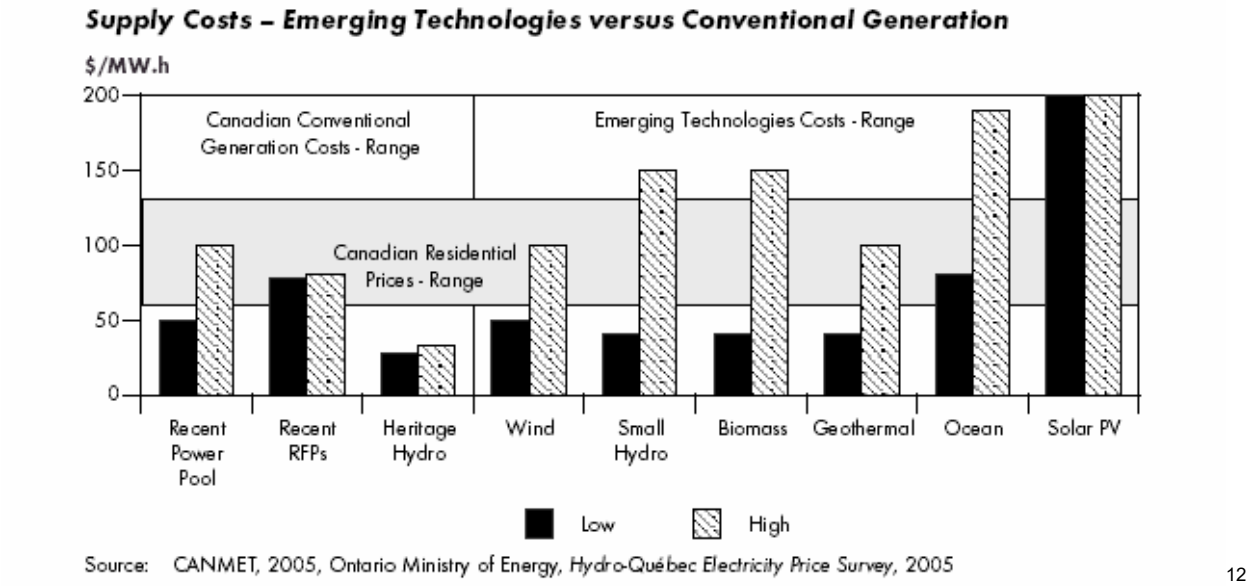
[10] Iowa Energy Center, "A History of Wind Energy," Iowa Energy Center website, http://www.energy.iastate.edu/renewable/wind/wem/wem-04_history.html accessed December, 2006

[11] National Energy Board, "Emerging Technologies in Electricity Generation – An Energy Market Assessment March 2006," p. xiv, http://www.neb-one.gc.ca/energy/EnergyReports/EMAEmergingTechnologiesElectricity2006_e.pdf accessed February 2007



12

It is now possible for supporters of clean energy to "buy" wind energy – by paying a higher rate or paying an annual fee. The Pembina Institute has a program where the amount of power consumed by the average computer over a three year period has been calculated. Then an equivalent amount of wind power credits have been purchased, which in effect allows the computer user to pay the premium for the wind generated power that is supplied to the electrical grid.[13] This study was produced on a wind-powered computer.

Ocean energy power generation technology is in its infancy, but it is growing fast. A wide variety of devices are being built and tested by brilliant inventors and bold entrepreneurs around the globe. Energy can be extracted from the ocean in several ways; thermal gradient, salinity gradient, wave energy and tidal energy. Tidal energy technology can be further divided into tidal stream and barrage type power generation. Both wave and tidal stream technologies are at similar stages of development, with many different designs being designed and tested now. The first full scale models of both wave and tidal stream power generation devices will occur in 2007. Barrage type tidal power has been in use for many years, notably in Canada at the Annapolis power plant in Nova Scotia and also in France.

[12] Ibid. p.7
[13] The Pembina Institute, "The Power to Make a Difference," Pembina Institute website, http://www.pembina.org/wind/wind_power.php, accessed January 2007

Remote Off-Grid Locations

Remote off-grid locations are especially significant for alternative energy generation because they are special cases where conventional energy solutions are not available or practical.

Remote locations, as the name implies, are places where small communities are isolated and do not have access to the modern conveniences enjoyed by most Canadians. Things that others take for granted, like telephone service, cable television, internet connectivity or natural gas piped to the house are often simply not available. Or if they are available, they come in a different form that is undoubtedly more expensive and often unreliable. In such places, electrical power usually comes from gasoline or diesel powered generators.

Off-grid locations are those where no connection to the electrical power grid is available. Often these are small communities that are accessible only by air or water. They can be more than a hundred kilometers from the nearest power lines. And this distance can be misleading, as it is measured as the seagull flies, with the most rugged terrain imaginable or bodies of water hundreds of feet deep standing between the community and the power lines. Running power lines to such communities is a tremendously expensive proposition.

The North American Power Grid refers to the electrical system that covers most of the continent. This network includes power generation facilities, distribution complexes, high voltage transmission lines and local power lines. All of these components are interconnected, which allows the demand for electricity to be balanced against electrical generation on a continent-wide scale. In control rooms across North America, technicians are monitoring the load on their portion of the grid and adjusting the generation capacity to suit regional demand. The principal control rooms are often located at a power generation facility, which may be a hydroelectric dam, a coal-fired plant or a nuclear power plant. The grid has been shown to be somewhat vulnerable in the past few years, as when an overload at a distribution centre in Ohio caused a huge blackout over most of Eastern Canada and the Northeastern United States in 2004.

So remote off-grid locations are places where there is no electrical service, and connection is unlikely in the foreseeable future. The growth potential of these communities is limited by the lack of reliable electrical power, and in some cases the very viability of the community is threatened.

The Significance of Remote Off-Grid Communities

There are many remote off-grid communities in British Columbia, but this phenomenon is by no means limited to BC. There are remote off-grid communities all over the world. In developing countries where the national electrical grid infrastructure is not well developed there are thousands of communities where electrical power, if available at all, is provided by diesel generators. The billions of dollars required to build a large scale power generation plant are not easy to come by. These locations are ideal places for smaller scale alternative energy projects.

Reliable power has great significance for these countries and for these communities. Reliable power permits the development of essential community assets such as health care facilities and communication infrastructure. One aspect of this infrastructure that is easily overlooked is reliable refrigeration, which has been described as the technology of survival and enhancement.[14] "Refrigeration is a vital part of the infrastructure necessary to deliver vaccines worldwide. Thousands of lives have been saved by vaccines for diseases such as polio, measles, chicken pox and hepatitis. Yet as many as three million children die every year from diseases that are preventable with available vaccines."[15] Reliable refrigeration is essential for these vaccines and other medical supplies to stay at the cool, stable temperatures that they require, and that requires reliable power.

In developed countries, remote communities' access to the outside world is a very important aspect of the people's development. Schoolchildren's educational opportunities are enhanced by access to the internet and the view of the outside world that it brings. And First Nations artists in a remote coastal village can find markets for their art through online galleries.

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[14] Ronald P. Vallort, "Refrigeration: Technology for Survival," *ASHRAE Journal*, August 2004, http://web.ebscohost.com.ezproxy.royalroads.ca/ehost/pdf?vid=5&hid=4&sid=c1434199-55ec-441e-9852-19d99dbb0944%40sessionmgr3 , accessed December 2006

[15] Ibid.

Ocean Energy in British Columbia – Government and NGOs

The Alternative Energy Task Force

The Premier of the Province of British Columbia created the Premier's Technology Council to advise him on technology related issues that affect British Columbia and its citizens. The Council produced an alternative energy strategy for BC, and one of the market opportunities identified in the strategy is "Remote power solutions for rural communities, including off-grid distributed generation from a variety of established and emerging alternative sources." [16] The Premier also established the Alternative Energy Task Force to provide advice and recommendations on how to implement the alternative energy strategy. British Columbia can be a world leader in sustainable energy. Government and Industry can create high-value jobs in profitable businesses by supplying smart, sustainable energy solutions to B.C., to Canada and to the world.[17]

BC Progress Board

Established by the Premier in 2001, the BC Progress Board is "tasked with benchmarking BC's economic and social performance over time and relative to other jurisdictions." [18] In November 2005, the BC Progress Board tabled a discussion paper on energy with the provincial government. The paper, "Strategic Imperatives for British Columbia's Energy Future", was prepared for the Board by Sage Group Management Consultants. This document surveys BC's current energy situation, outlines energy opportunities for BC and specific actions that should be taken. The first of six Strategic Imperatives says that BC must protect and promote its real advantages in the energy sector. It describes how growing the energy sector in BC will underpin economic growth for the province and that growth needs to come from both conventional and alternative sources of supply. [19]

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[16] BC Ministry of Energy, Mines and Petroleum Resources, "Alternative Energy and Power Technology: A Strategy for BC," BC Ministry of Energy, Mines and Petroleum Resources website, http://www.gov.bc.ca/empr/down/alternative_energy_task_force_strategy_final_april_5_05.pdf, accessed January 2007

[17] BC Ministry of Energy, Mines and Petroleum Resources, "A Vision and Implementation Plan for Growing a Sustainable Energy Cluster in British Columbia" BC Ministry of Energy, Mines and Petroleum Resources website, http://www.em.gov.bc.ca/AlternativeEnergy/AEPT_report.pdf, accessed January 2007

[18] BC Progress Board, "Strategic Imperatives for British Columbia's Energy Future," BC Progress Board website, http://www.bcprogressboard.com/2005Report/EnergyReport/Energy_Final.pdf, accessed January 2007

[19] Ibid.

BC Innovation Council (BCIC)

The BC Innovation Council (BCIC) is a crown agency of the Province of British Columbia whose mandate is "to accelerate and expand science and technology-based economic development to make British Columbia one of the world's top ten technology centres by 2010." [20] BCIC supports innovation through targeted initiatives to build on the strengths and abilities of the province and of the companies and organizations within it. One of these initiatives is the Ocean Renewable Energy Group (OREG). BCIC was instrumental in the launching of OREG and has provided invaluable support to permit the organization to develop. BCIC provides funding for a range of programs from scholarships to research and development to support and encourage innovation.[21]

BC Energy Plan

The last Energy Plan was issued by the Province of BC in 2002. The plan reflects the government's vision of the energy sector, the goals it has set and the path to achieving those goals in an environmentally responsible way.[22] A new version of the Energy Plan has been under development over the last year and is eagerly awaited by the alternative energy industry. While the report has not yet been released at the time of writing, the Throne Speech of February 13, 2007 reveals some of the initiatives that will be in the new Energy Plan:

- All electricity produced in BC will have net zero greenhouse gas emissions by 2016,
- At least 90 per cent of BC's electricity will come from clean, renewable sources,
- Bioenergy, geothermal energy, tidal, run-of-the-river, solar, and wind power are all potential energy sources in a clean, renewable, low-carbon future,
- A new $25-million Innovative Clean Energy Fund will be established to encourage the commercialization of alternative energy solutions and new solutions for clean remote energy that can solve many challenges we face right here in B.C.[23]

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[20] BC Innovation Council, "Welcome," BC Innovation Council website, http://www.bcinnovationcouncil.com/ accessed February 2007
[21] BC Innovation Council, "Overview," BC Innovation Council website, http://www.bcinnovationcouncil.com/programs/ accessed February 2007
[22] BC Ministry of Energy, Mines and Petroleum Resources, "Energy For our Future: A Plan For BC," BC Ministry of Energy, Mines and Petroleum Resources website, http://www.gov.bc.ca/empr/down/energy_for_our_future_sept_27.pdf, accessed January 2007
[23] The Government of British Columbia, "Speech From The Throne," BC Government website, http://www.leg.bc.ca/38th3rd/4-8-38-3.htm accessed February 2007

BC Hydro Integrated Electricity Plan (IEP)

Every two years, BC Hydro is required to submit an Integrated Electricity Plan (IEP) with the BC Utilities Commission, in accordance with the regulator's resource planning guidelines. The last IEP was filed in March 2006. It is a long term plan that outlines how BC Hydro intends to meet the needs of its customers over the next 20 years by ensuring that a reliable and cost-effective supply of electricity is available to its customers, while considering key environmental and social issues.[24] The plan recognizes that energy infrastructure involves very large expenditures and long development times, so it is based on long term forecasts and resource options. The current load forecast indicates that BC's energy needs will grow between 25 and 40 percent over the next 20 years. There is an electricity gap between this forecast and the projected capacity that must be filled by conserving more, building new capacity and buying more power from Independent Power Producers (IPPs).[25] IPPs are viable options for BC Hydro to add clean energy generating capacity through the development of projects using technologies including wind power, biomass, microhydro and, of course, ocean energy.

BC Hydro Remote Community Electrification Program (RCE)

BC Hydro has a desire to supply remote communities with power at prices comparable to what BC Hydro's customers pay in other parts of the province. Under the RCE program, BC Hydro would assume responsibility for the supply of electricity for remote communities that meet the selection criteria, and provide the power to the community at standard rates. BC Hydro has prepared a list of communities that have at least ten permanent residences and has conducted a survey to determine the level of need and the willingness of the community to participate in the program. The results of this survey have determined the priority list for the program.[26]

For a community to qualify for the RCE program, there must be a minimum of 10 permanent residences. In the Stuart Island area, there are 12 permanent residences according to the official records of Canada Post. These residences are on the islands and mainland surrounding Cardero Channel. BC Hydro would have to confirm that the Stuart Island area qualifies for the

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[24] BC Hydro, "What is the 2006 Integrated Electricity Plan (IEP)?" BC Hydro website, http://www.bchydro.com/info/epi/epi8970.html, accessed January 2007
[25] BC Hydro, "Challenges and Choices," BC Hydro website, http://www.bchydro.com/rx_files/info/info43492.pdf, accessed January 2007
[26] BC Hydro, 2006 Annual Report, (Vancouver: BC Hydro, 2006), http://www.bchydro.com/info/reports/2006annualreport/report45822.html, accessed January 2007

program, but if accepted, this program could be of tremendous benefit to the residents and businesses of the Stuart Island area.

BC Hydro's has established rates for its customers by zones:

- Zone I - The integrated system served mainly by hydroelectric (water) generation, to which 99% of customers are connected.
- Zone II - The non-integrated system (areas with no access to the integrated system) where electricity is generated by diesel and some small hydroelectric plants. [27]

Currently, the Zone II residential rate is 6.33 cents per KWh for the first 3000 KWh and 10.87 cents per KWh after that. The rate for businesses is 12 cents per KWh, compared to the cost of power generated by the diesel gensets in the Stuart Island area, which is about 29 cents per KWh.

Under the RCE program, there would be an opportunity for an IPP to sell power to the Non Integrated Electrical System. BC Hydro would buy power from the IPP and supply it to residents and businesses at Zone II rates. Customers are responsible, however, for providing a distribution line from the generators, built to BC Hydro standards. BC Hydro's objective is to supply 50% of the power for RCE from renewable sources.[28]

Triton Consultants Report

In 2002, Triton Consultants completed a study for BC Hydro that detailed the nature and extent of tidal energy resources in British Columbia.[29] This comprehensive report provides an extensive overview of the potential for the development of tidal power in BC as a source of Green Energy. The Triton report is a tremendous resource for anyone interested in tidal power in BC and has been invaluable in the preparation of this study on tidal power potential in the Stuart Island area.

The Triton study included five principal elements;

- a detailed assessment of the tidal current resource available in BC,

[27] BC Hydro, "How Your Rates Are Determined," http://www.bchydro.com/policies/rates/rates759.html, accessed January 2007
[28] Nick Hawley, telephone interview by author, January 19, 2007
[29] Triton Consultants, "Green Energy Study for British Columbia. Phase 2: Mainland. Tidal Current Energy," http://homepage.mac.com/max.larson/Triton/download/environment3928.pdf accessed January 2007

- preliminary tidal modeling studies,
- case studies of one large (800 MW rated capacity) and one small (43 MW rated capacity) potential tidal current power site, including indicative energy costs,
- an initial evaluation of environmental issues,
- and a review of selected tidal current technologies which are in various stages of development.[30]

The study presents a number of key conclusions, including findings that tidal current energy is predictable, regular, will not be affected by global climate change and has small environment impact. It determines that tidal current energy generation costs are competitive with other green energy sources at 11 cents per KWh for a large site and 25 cents per KWh for a small site. These costs are expected to reduce as the technology matures.

The Triton study also notes there are some challenges that the tidal power industry faces:

- The technology is in its infancy
- Tidal power generation fluctuates significantly over a typical day
- There is no significant government funding in Canada, which is a serious impediment to the development of tidal power technologies.[31]

[30] Ibid. p.7
[31] Ibid. p.8

BC Ocean Energy Industry

In British Columbia there has been considerable development activity in tidal power energy generation. The most advanced development site is the Pearson College / Clean Current site at Race Rocks, which has been in the water and generating power since late 2006. This project has done a great deal to raise the profile of tidal energy in BC and in Canada. The turbine is rated at 65 KW and thus is not at commercial scale, but it is an off-grid installation which makes it germane to this study. The turbine is providing power to the weather station and instrumentation at Race Rocks, near Victoria, BC, and is reducing dependence on the diesel generators that have been providing the power there for decades.

In addition to Race Rocks, there are currently three more development sites in the province. Investigative Use Permits have been granted for the following sites:

Maude Island/Canoe Pass - Canoe Pass Tidal Energy Corp
Discovery Passage - 6420800 Canada Ltd (Lunar Energy)
Discovery Passage - BC Tidal Energy Corp[32]

The Canoe Pass project is working its way through the approval process and is scheduled to conduct design work in 2007 with installation targeted for 2008. This project employs a unique installation design that features a span across the narrow channel to facilitate access during installation and testing, and ease of power connections.

Lunar Energy plans to begin work at the Discovery Passage site in late 2009, after testing of the 1 MW device at the EMEC facility in Scotland in late 2008. The site is near Seymour Narrows, one of the largest tidal power resources in Canada.

There are a number of technology developers working in BC – more information on them can be found in the Technology section.

[32] Neil Banera, MEMPR, email correspondence with author, January 24, 2007

Ocean Energy in Canada – Government and NGOs

The two lead organizations for ocean energy in the Government of Canada are Natural Resources Canada and the National Research Council. As it is the government ministry with responsibility for alternative energy initiatives, Natural Resources Canada is the primary vehicle for direct government funding of ocean energy. However, as ocean energy is in the developmental and demonstration phases, the National Research Council may play a larger role in a project.

Natural Resources Canada (NRCan)

Natural Resources Canada is the name for the natural resources department in the government of Canada and is represented in government by a Minister at the Cabinet table. NRCan works to ensure the responsible development of Canada's natural resources, including energy, forests, minerals and metals. NRCan also uses our expertise in earth sciences to build and maintain an up-to-date knowledge base of Canada's landmass and resources.[33] The funds available for NRCan are determined each year through the federal budgeting process. Therefore the priorities of the government in power determine the emphasis to be placed on the ministry and its activities, so often this is a purely political decision. Such is the case with alternate energy, which has not received a great deal of attention from the Government of Canada through 2006.

However, on January 17, 2007, Minister Gary Lunn announced that 230 million dollars would be allocated as incentives to industry to reduce greenhouse gas emissions and to develop alternative energy technologies.[34] Only two days later, Prime Minister Harper announced the ecoEnergy Renewable Initiative, which will provide up to 1.5 billion dollars in incentives over ten years to increase clean, renewable energy production in Canada. While critics argue that this initiative is essentially a resurrection of the previous government's proposed program, and that this is not a large amount of money relative to Canada's total annual budget, it is nevertheless a step in the right direction and will help to raise the profile of alternate energy technology developers in the minds of the public.

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[33] Natural Resources Canada, "About Us," Natural Resources Canada website, http://www.nrcan-rncan.gc.ca/inter/aboutus_e.html, accessed January 2007

[34] Natural Resources Canada press release, "Canada's New Government Launches ecoEnergy Technology Initiative," January 17, 2007, Natural Resources Canada website, http://www.nrcan-rncan.gc.ca/inter/aboutus_e.html, accessed January 2007

CANMET Energy Technology Centre (CETC)

The CANMET Energy Technology Centre is a federal government organization under the umbrella of Natural Resources Canada. CETC has a mandate to work with Canadian businesses to develop and alternative and renewable energy technologies. CETC has available laboratory facilities and research expertise. These facilities and services can be available on a cost-shared basis. One of CETC's stated priorities is the development of alternative and renewable energy technologies.[35] CETC has an Emerging Technologies Program that can provide up to 50% repayable funding assistance for technical assessments, prototype development and field trials. This program supports, among other things, the development of technical solutions that contribute to a cleaner environment.[36]

Sustainable Development Technology Canada (SDTC)

Sustainable Development Technology Canada (SDTC) was established by the Government of Canada in 2001 as a not-for-profit foundation to help finance the development of clean technologies. The foundation draws from an investment fund of $ 550 million and reports to Parliament through NRCan. SDTC's mission is to act as a catalyst to build a sustainable technology infrastructure in Canada. SDTC helps entrepreneurs bridge the gap between research and commercialization by assisting them through the crucial phases of development and demonstration.[37] The phase in a product or technologies development that can incur the most cost and risk is the time when it must be proven in real world conditions, with models approaching full scale. SDTC grants help clean energy developers move through this stage towards full commercialization of the product.

In British Columbia, SDTC has made investments in tidal stream power generation demonstration projects at Race Rocks and Canoe Pass. These investments have made an important contribution to the development of tidal power generation in BC and in Canada.

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[35] CANMET Energy Technology Centre, "Frequently Asked Questions About CETC-Ottawa," CETC website, http://www.nrcan.gc.ca/es/etb/ctec/cetc01/htmldocs/FAQs/index_e.htm accessed February 2007.
[36] CANMET Energy Technology Centre, "Emerging Technologies Program," CETC website, http://www.nrcan.gc.ca/es/etb/ctec/cetc01/htmldocs/Groups/Funding%20Programs/fundprog_emerging_technologies_e.htm accessed February 2007.
[37] Sustainable Development Technology Canada, "About SCTC – SDTC Profile," SDTC website, http://www.sdtc.ca/en/about/index.htm, accessed January 2007

National Research Council (NRC)

One of the main access points to the federal government for technology developers is the National Research Council (NRC). NRC was created in 1916 as the Canadian government's agency for research and development; it falls under the Ministry of Industry. The mandate for NRC is laid out in the NRC Act and the first mandate is "undertaking, assisting or promoting scientific and industrial research in different fields of importance to Canada."[38]

National Research Council – Institute for Ocean Technology (NRC-IOT)

The NRC is organized into more than twenty institutes and programs.[39] One of these institutes is the Institute for Ocean Technology (NRC-IOT) which was established in 1985 to support Canada's ocean technology industry by providing technical expertise. IOT conducts ocean engineering research through modeling of ocean environments, predicting and improving the performance of marine systems, and developing innovative technologies that bring benefits to the Canadian marine industry.[40] NRC-IOT works with Canadian companies to develop prototypes of various kinds of surface and underwater technologies, then commercialize them. In 2003 the NRC-IOT opened the Ocean Technology Enterprise Centre (OTEC) in St. John's Newfoundland. OTEC provides a place for ocean technology companies to conduct research and develop their technologies and business opportunities.[41] Resources such as office equipment and conference facilities are provided and the Canada Institute for Scientific and Technical Information is nearby.

NRC Industrial Research Assistance Program (IRAP)

The Industrial Research Assistance Program (IRAP) is a program to provide assistance to small and medium-sized Canadian enterprises (SME). This assistance takes many forms and includes technological and business advice and financial assistance. IRAP funding can help SMEs to make investments in people or research and development programs to realize the full

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[38] National Research Council Canada, "Our Mandate," NRC website, http://www.nrc-cnrc.gc.ca/aboutUs/mandate_e.html, accessed January 2007
[39] National Research Council Canada, "Corporate Overview," NRC website, http://www.nrc-cnrc.gc.ca/aboutUs/corporateoverview_e.html, accessed January 2007
[40] National Research Council – Institute for Ocean Technology, "About Us," NRC-IOT website, http://iot-ito.nrc-cnrc.gc.ca/about_e.html, accessed January 2007
[41] National Research Council – Institute for Ocean Technology, "Ocean Technology Enterprise Centre," NRC-IOT website, http://iot-ito.nrc-cnrc.gc.ca/enterprise_e.html, accessed January 2007

potential of their innovations.[42] IRAP's mandate is to stimulate wealth creation for Canada through technological innovation. It does this by providing assistance to the SMEs that make up the majority of businesses in Canada. In addition to funding, IRAP helps Canadian companies by making available technology advisors that can provide confidential advice to help build their innovation capability.[43]

NRC Canadian Hydraulics Centre (NRC-CHC)

The Canadian Hydraulics Centre is a business unit of the NRC. Located in Ottawa, it is one of the largest hydraulic engineering laboratories in North America and is equipped with some of the world's most advanced technology for wave generation and coastline physical modeling. The centre is equipped to investigate and solve problems through numerical models, then validate those numerical models with large scale physical models.[44] In 2006, the CHC produced a technical report entitled Inventory of Canada's Marine Renewable Energy Resources which detailed the location and size of wave and tidal energy resources.[45]

The Ocean Renewable Energy Group (OREG)

The Ocean Renewable Energy Group (OREG) is a Canadian organization dedicated to leading the effort to make Canada a leader in ocean energy technologies. OREG is a valuable resource for information on ocean energy technologies and developers from around the world. OREG has produced a plan called *The Path Forward*, which outlines a plan for Canada in the world of renewable ocean energy.[46] In the words of OREG Chairman Chris Knight, "This Plan has two purposes. First we need to identify immediate actions that will springboard the Canadian ocean energy sector to a world-wide leadership position alongside the UK and other European Union countries. Secondly, we need to set out a broader sectoral development plan as the foundation to maintain that leadership position and make ocean renewable energy a fundamental part of

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[42] NRC-IRAP, "Innovation at work in Canada," NRC-IRAP website, http://irap-pari.nrc-cnrc.gc.ca/main_e.html, accessed January 2007
[43] NRC-IRAP, "About NRC-IRAP," NRC-IRAP website, http://irap-pari.nrc-cnrc.gc.ca/aboutirap_e.html, accessed January 2007
[44] NRC Canadian Hydraulics Centre, "Coastal Engineering- Physical and Numerical Modelling," NRC-CHC website, http://chc.nrc-cnrc.gc.ca/English/Coastal/Coastal_e.html, accessed January 2007
[45] A. Cornett, "Inventory of Canada's Marine Renewable Energy Resources CHC-TR-041," http://www.oreg.ca/docs/Atlas/CHC-TR-041.pdf accessed January 2007
[46] OREG, "The Path Forward," OREG website, http://www.oreg.ca/docs/OREG%20docs/OREG%20_The%20Path%20Forward_v7sm.pdf, accessed January 2007

Canada's business, economic, energy and environmental future."[47] OREG has organized symposia that have brought tidal power experts from around the world to share their wisdom and insights with Canadians from industry, government and academia. More information on OREG can be found in the Organizations section of this paper.

Western Economic Diversification

Western Economic Diversification Canada (WD) was established to help broaden the economic base of the western provinces and receives an annual allocation, approved by Parliament, for grants and contributions that support a wide range of programs responding to Western Canada's economic development needs and priorities.[48] WD has made investments in BC ocean energy projects and so is a valuable contributor to the development of tidal energy expertise in the province.

Nova Scotia Power

Canada is home to one of the first tidal power generating facilities in the world. The Annapolis Power Station at Annapolis Royal, Nova Scotia is a barrage-type tidal power generation plant that harnesses potential energy from the tides of the Bay of Fundy. The plant became operational in 1984, and until recently was one of only three tidal power plants in the world. Owned and operated by Nova Scotia Power, the Annapolis Power Station can produce up to 20 MW daily.[49]

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[47] Ibid.
[48] Western Economic Diversification, "WD Programs," Western Economic Diversification website, http://www.wd.gc.ca/programs/default_e.asp, accessed January 2007
[49] Nova Scotia Power, "Ebb and Flow,"Nova Scotia Power website, http://www.nspower.ca/environment/green_power/tidal/index.shtml, accessed January 2007
[50] Nova Scotia Power, "Helping Return Whale To Bay of Fundy," http://www.nspower.ca/about_nspi/in_the_news/2004/08242004.shtml accessed February 2007

In January 2007, Nova Scotia power announced that it will continue to be a leader in ocean energy generation with a new tidal stream demonstration project in the Bay of Fundy. The project will use a turbine designed and manufactured by OpenHydro of Ireland. If the demonstration project is successful, Nova Scotia plans to install more turbines to create the largest in-stream tidal unit integrated into an electricity grid in the world.[51]

EnCana

EnCana Corporation deserves a mention here because it is a major sponsor of the tidal power demonstration project at Race Rocks and is demonstrating to industry that investing in clean energy is good business. The Encana Environmental Innovation Fund contributed three million dollars to the project.[52]

[51] "Nova Scotia Power Takes Another Step Towards Tidal Power Pilot Project," Nova Scotia Power press release (Halifax, NS, January 12, 2007). From Nova Scotia Power website, http://www.nspower.ca/about_nspi/in_the_news/2007/01122007.shtml, accessed January 2007

[52] EnCana Corporation, "Pearson College - EnCana - Clean Current Tidal Power Demonstration Project at Race Rocks," Encana website, http://www.encana.com/responsibility/eif/fundedprojects/P1162484703969.html, accessed January 2007

Tidal Resources in Canada

Canada is richly endowed with tidal resources – a 2006 study identified more than 42,000 MW of potential tidal energy resources in the oceans surrounding the country. Expressed differently, that represents about 365 Terawatt hours per year, which is approximately seventy percent of Canada's present electrical power consumption.[53] In 2006, the Canadian Hydraulics Centre produced a technical report entitled Inventory of Canada's Marine Renewable Energy Resources which detailed the location and size of wave and tidal energy resources.[54] Triton Consultants, of Vancouver, was engaged to conduct a study that identified tidal resources over 1 MW and locate them geographically. Triton's methodology included identification of passages or reaches with strong currents, determining the basic parameters of each site and estimating the mean power density and annual mean power from those parameters.[55] Triton's findings are included in the CHC report, which is the first step in a three year project to create a Digital Atlas of Canadian Marine Renewable Resources. In Canada, a total of 190 sites were identified with potential mean power over 1 MW. The largest number of sites is in British Columbia, but the largest resources by far are in Nunavut.[56]

Another organization that has taken an interest in Canada's ocean energy resources is EPRI. In 2006, EPRI released a series of studies of tidal resources on the East Coast of North America. Two Canadian locations in the Bay of Fundy were included in the studies, Minas Basin in Nova Scotia and Head Harbour Passage in New Brunswick. Comprehensive feasibility studies were produced that detailed the potential for tidal power generation facilities in the waters of the Bay of Fundy.

Bay of Fundy and Minas Basin

To produce practical amounts of tidal power with a barrage system, a difference of a least five metres between high and low tide is needed. There are only about 40 sites around the world

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[53] Michael Tarbotton and Max Larson, *Canada Ocean Energy Atlas (Phase 1)Potential Tidal Current Energy Resources Analysis Background,* Annex A of Inventory of Canada's Marine Renewable Energy Resources CHC-TR-041, National Research Council Canada, April 2006, p.15, http://www.oreg.ca/docs/Atlas/CHC-TR-041.pdf accessed January 2007

[54] A. Cornett*, Inventory of Canada's Marine Renewable Energy Resources CHC-TR-041*, National Research Council Canada, April 2006, http://www.oreg.ca/docs/Atlas/CHC-TR-041.pdf accessed January 2007

[55] Ibid., page 82

[56] Ibid., page 83

with this kind of tidal range. Currently in Canada, the only practical site is the Bay of Fundy.[57] Minas Basin is a branch of the upper end of the Bay of Fundy.

"Today, the Basin's oceanography is dominated by tides that exceed those of any other location in the world. They are even 1.5 metres higher than in nearby Chignecto Bay, because the "Coriolis Force", produced by the rotation of the Earth, nudges the tidal bulge towards the southeastern side of the Bay of Fundy. The average tidal range is an impressive 13 metres, while spring tides up to 16 metres are common. The large tidal amplitude causes more than 10 cubic kilometres of seawater, weighing 10 billion tonnes, to flow into and out of the Basin twice daily, more than forty times the flow of the St. Lawrence River. As the Basin fills, the weight of water causes the surrounding land to dip slightly under the load. The water squeezes through the 5 kilometre wide gap at Cape Split, a bottleneck that causes the incoming water to pile up in Scots Bay, producing a noticeable difference in the height of the sea surface. The inrushing flow reaches speeds of 4 metres per second (8 knots), swirling past Cape Split in a maelstrom of turbulent currents and gyres."[58]

Naturally, the enormous tidal range and powerful currents at Minas Basin have attracted a great deal of interest from people and organizations involved in tidal power generation. There are two key advantages to the Minas Basin site – proximity to the North American power grid and ease of transportation of material and equipment for installation of a tidal power generation facility. In January 2007, Nova Scotia Power took the first step towards realizing the potential of the resource when it awarded a contract for the supply and installation of a tidal power generation device for a demonstration project to OpenHydro.

Hudson's Strait and Ungava Bay

Over 70% of Canada's potential tidal energy resources are in Hudson's Strait, which connects the waters of Hudson's Bay to the North Atlantic Ocean.[59] Two locations adjacent to Mill Island and another at Gray Strait are enormous resources, with potential resources of several thousand MW each, totaling just under 25,000 MW. Ungava, a bay off Hudson's Strait in Northern Quebec, has three locations with potential tidal resources totaling more than 3,000

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[57] Nova Scotia Power, "Tidal Technology,"Nova Scotia Power website, http://www.nspower.ca/environment/green_power/tidal/ technology.shtml, accessed January 2007
[58] Bay of Fundy Ecosystem Partnership, "Fundy's Minas Basin - Multiplying The Pluses of Minas," Bay of Fundy Ecosystem Partnership website, http://www.bofep.org/minas1.htm, accessed January 2007
[59] Cornett, *Inventory of Canada's Marine Renewable Energy Resources* p.83

MW.[60] The sheer magnitude of these resources merits further investigation into the possibility of developing these sites to extract clean energy. Unfortunately, the remoteness of the locations means that a great deal of money would have to be invested in power transmission infrastructure to connect to the North American electrical grid. This is particularly true of the locations near Mill Island which are hundreds of kilometers from the nearest grid connection point. This means that these resources likely will not be developed for many years. On the positive side, both tidal power generation technology and power transmission technology will have had time to evolve in the intervening years, possibly making the resource more financially feasible to develop.

British Columbia Coast

Triton Consultants identified 89 sites on the BC coast with potential tidal resources greater than 1 MW.[61] The great advantage of many of the BC sites is their relative proximity to the grid, often within a few kilometers – in some cases the tidal resource is virtually adjacent to a grid connection point. In fact, the Canoe Pass site is situated directly under a 25 KV distribution line.[62] However, the extremely rugged terrain of the BC coast means that a relatively short distance as the seagull flies might prove to be a formidable challenge when contemplating laying subsea cable or stringing overhead wires. Further details can be found in the Tidal Resources in BC section of this report.

Marine traffic is a concern along the BC coast and so this has the effect of limiting the feasibility of developing some tidal power resources or limiting the devices that might be used. This factor is compounded by the fact that the largest tidal stream resources occur in relatively narrow channels or passages where transit by marine traffic cannot be suspended for weeks or months while tidal power generators are installed.

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[60] Tarbotton and Larson, *Canada Ocean Energy Atlas (Phase 1)* p.16
[61] Cornett, *Inventory of Canada's Marine Renewable Energy Resources* p. 83
[62] Canoe Pass Tidal Energy Consortium, *Canoe Pass Tidal Energy Demonstration Project – Detailed Project Description*, March 8, 2006

Tidal Power Internationally

Tidal power generation is not well known in North America, in spite of the fact that Canada boasts one of only a few commercially operating tidal power plants in the world at Annapolis Royal, Nova Scotia. This facility will be discussed in detail in the Canadian section. Ocean energy, including both tidal and wave energy, has attracted much more attention internationally, especially in Europe. A number of companies developing technology to extract clean, renewable energy from the ocean and demonstration projects are underway in several countries. The following is a review of tidal energy activities around the world.

France

Completed in 1967, the Rance Tidal Power Plant, at Mont Saint-Michel is by far the largest in the world with a generating capacity of 240 MW.[63] A barrage type system, the power plant required the construction of a structure 750 metres long and 13 metres high. Twenty four axial flow turbines each 5.3 metres in diameter produce 10 MW each. The plant has operated without major incidents or breakdowns and produces electricity at a cost that is lower than Electricité de France's average generation costs.[64]

Russia

In the late sixties, a small experimental system with an installed capacity of 400 KW was built in Russia at Kislogubsk near Murmansk.[65] Design studies followed at four locations, two in the White Sea and two in the Sea of Okhotsk.[66] The study of the Tugur tidal power station in the far eastern area of Russia rated its capacity at 6,800 MW but the remoteness of the location makes it unlikely to be developed in the near future.[67] In December 2006, an experimental floating tidal

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[63] Electricitie de France, "The Rance tidal power plant, power from the ocean," EDF website, http://www.edf.fr/html/en/decouvertes/voyage/usine/retour-usine.html, accessed December 2006
[64] Ibid.
[65] World Energy Council, "Survey of Energy Resources – Tidal Power," WEC website, http://www.worldenergy.org/wec-geis/publications/reports/ser/tide/tide.asp, accessed December 2006
[66] Research Institute for Sustainable Energy, "Tidal Power Around the World," RISE website, http://www.rise.org.au/info/Tech/tidal/index.html, accessed December 2006
[67] Victor N. Minakov, "Transmission Line Project Linking the Russian Far East with the DPRK (Chongjin)" paper presented at Energy Forum held in Niigata, February 2004 http://www.nautilus.org/aesnet/Minakov_Niigata_2004_Peport.pdf, accessed December 2006

power plant was launched and is being towed to an existing test site at Kislogubskaya Tidal Power Plant in the Barents Sea.[68]

China

China has been experimenting with tidal power generation for many years, and in 1984, eight tidal power plants were in operation. At least two of these plants are still in operation. The Jiangxia power plant in Zhejiang province has a capacity of 3.2 MW from five turbine units. Noteworthy for this study of the use of tidal power generation for remote communities is the Haishan power plant on Maoyan Island, also in Zhejiang province. This small plant, with a capacity of only 0.25 MW, serves an isolated community of 760 people. It has been in continuous operation since 1975.[69] More recently, China has developed two experimental tidal stream power generators, Wanxiang I and Wanxiang II, which are currently under test.[70]

The United Kingdom

The preeminent demonstration project of tidal stream generation technology has been in place since 2003. Seaflow is a marine current turbine that generates 300 KW and is installed off Lynmouth on the North Devon Coast of UK, making use of the strong tides within the Bristol Channel. Seaflow is a test site for the technology, to measure the performance and loads on the turbine, and to develop techniques for installing and operating such machines in a marine environment.[71] The project was sponsored by the UK Department of Trade and Industry (DTI) and the European Commission and was designed, manufactured and installed by a consortium that included companies and organizations from the UK and Germany.

The Seaflow project uses a single rotor mounted on a monopole installed in the seabed. The equipment is manufactured by Marine Current Turbines (MCT) and one of the principal design features is the ability to raise the turbines above sea level for servicing and maintenance. More

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[68] "UES tests tidal generation," *International Water and Dam Construction*, November 29, 2006, http://www.waterpowermagazine.com/story.asp?sc=2040562&ac=7959438, accessed December 2006
[69] E Van Walsom, "Barriers against tidal power," *International Water and Dam Construction*, September 3,2003, http://www.waterpowermagazine.com/story.asp?storyCode=2022354, accessed December 2006
[70] Zhang Liang, "Activities For Ocean Energy Exploration In China" presentation at 11th IEA-OES meeting Lisbon, Portugal, November 14-15, 2006, http://www.iea-oceans.org/presentations/China.pdf, accessed December 2006
[71] IT Power, "Seaflow Marine Current Turbine," IT Power website, http://www.itpower.co.uk/seaflow.htm, accessed December 2006

about the MCT device can be found in the section on tidal stream generator technologies. In 2005 MCT received a grant from DTI to begin development of a 1 MW demonstration unit.

The UK government has made a strong investment in research and development by opening the New and Renewable Energy Centre (NaREC). NaREC is a Centre of Excellence, fast-tracking concept evaluation, feasibility studies and prototype evaluation and testing through to early commercialization.[72] NaREC was built to meet the challenges put forward to enable development of green energy technologies. Construction began in 2003 and the facilities in Blyth were completed in 2006. The Marine Test Facility includes wave and current generators for testing at 1/10 scale.[73]

The European Marine Energy Centre (EMEC) is located in the Orkney Islands off the North coast of Scotland. EMEC was established to help take the development of ocean energy devices to the commercial stage. "As the first centre of its kind to be created anywhere in the world, we offer developers the opportunity to test prototype devices in unrivalled wave and tidal conditions. Wave and tidal energy converters are connected to the National Grid via seabed cables running from open-water test berths. Testing takes place in a wide range of sea and weather conditions, with comprehensive, round-the-clock monitoring."[74] The tidal test facility, completed in 2006, is located in the Fall of Warness off the island of Eday. It features five test berths at water depths ranging from 25 to 50 metres, each with its own connection cable to the local power grid and control facility.[75]

No discussion of ocean energy in the UK would be complete without mentioning the Pelamis. This wave energy device is manufactured by Ocean Power Delivery (OPD) of Scotland. The Pelamis is a semi-submerged, articulated structure composed of cylindrical sections linked by hinged joints. The wave-induced motion of these joints is resisted by hydraulic rams, which pump high-pressure oil through hydraulic motors via smoothing accumulators. The hydraulic motors drive electrical generators to produce electricity.[76] Three Pelamis wave energy

[72] NaREC, "Harnessing the potential of technology," NaREC website, http://www.narec.co.uk/index.php, accessed December 2006
[73] NaREC, "Marine Test Facility," NaREC website, http://www.narec.co.uk/facilities-wave-and-tidal-dock.php, accessed December 2006
[74] EMEC, "Home," EMEC website, http://www.emec.org.uk/index.asp, accessed December 2006
[75] EMEC, "Tidal Site," EMEC website, http://www.emec.org.uk/tidal_site.asp, accessed December 2006
[76] OPD Ltd., "The Pelamis Wave Energy Converter," OPD website, http://www.oceanpd.com/Pelamis/default.html, accessed December 2006

generators were delivered to Portugal in late 2006 for the initial phase of the world's first commercial application of wave energy power generation.[77]

Northern Ireland

The government of Northern Ireland has made strong commitments to renewable energy and tidal power generation. In February 2006 the government launched its £59 million Environment & Renewable Energy fund, which will help harness the country's natural resources to produce power and reduce dependence on fossil fuels.[78]

MCT's SeaGen, scheduled to be installed in Strangford Lough in late 2006, will be connected to the local grid and will provide electricity to approximately 800 homes in the Portaferry and Strangford areas.[79] The device installed will be a twin turbine with design capacity of 1 MW installed on a surface piercing monopole for easy of access for testing or maintenance. Installation challenges at the site have pushed the installation back to the spring or early summer of 2007.[80]

Ireland

Ireland has made a significant commitment to ocean energy through the organization Sustainable Energy Ireland (SEI). Secure funding for ocean energy technology development has been assured through 2025. Phase 1 activities of the Ocean Energy Strategy include the establishment of the Galway Bay test Site. Quarter scale testing of two wave energy devices, the Wavebob and the OE Bouy, are underway.[81] Ireland is also home to OpenHydro, a tidal stream power technology developer that was recently selected as the device supplier for a new demonstration project in the Bay of Fundy.

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[77] Rich Bowden, "Portugal Announces New Wave Energy Project," *Renewable Energy Access*, http://www.renewableenergyaccess.com/rea/news/story?id=46206, accessed December 2006

[78] "Hain aims to make NI European leader in renewable energy," Northern Ireland Office press release, February 27, 2006. From Northern Ireland Office website, http://www.nio.gov.uk/media-detail.htm?newsID=12785, accessed December 2006

[79] "MCT Welcomes Northern Ireland's Funding Commitment To Renewable Energy," MCT press release, February 27, 2006. From MCT website, http://www.marineturbines.com/mct_text_files/MCT%20WELCOMES%20NORTHERN%20IRELAND'S%20FUNDING%20COMMITMENT%20TO%20RENEWABLE%20ENERGY%2027FEB06.pdf, accessed December 2006

[80] Peter Fraenkel, Marine Current Turbines, email correspondence with author, January 9, 2007

[81] Katrina Polaski and Tony Lewis, "Ocean Energy in Ireland National Policies and Strategies for RD&D and Commercialisation of Ocean Energy" presentation at 11th IEA-OES meeting Lisbon, Portugal, November 14-15, 2006, http://www.iea-oceans.org/presentations/Ireland.pdf, accessed December 2006

New Zealand

In December 2006, the New Zealand government announced a 8 million dollar funding package to help the country become a world leader in ocean energy technology. Fourteen marine energy projects are currently being planned, with a 200 MW tidal power plant at Kaipara Harbour being the closest to implementation. Crest Energy predicts the first of 200 turbines could be in place within two years. A massive project being contemplated by Neptune Energy could see as many as 13,000 turbines tapping the tidal stream resource at Cook Strait.[82]

Portugal

Wave energy has been the focus for Portugal and it has the distinction of hosting the first commercial installation of the Pelamis wave energy device. The site is five kilometers off the coast of northern Portugal, near Póvoa de Varzim. Three Pelamis units will be used in the initial phase with a total capacity of 2.25 MW. A further 28 units will be supplied if the first phase performs well.[83] As of this writing, the project is waiting for suitable weather to permit installation of the mooring system. The project is expected to be operational early in 2007.

United States

In the United States, EPRI has taken the lead role in promoting ocean energy and in conducting research into suitable locations for both tidal and wave energy projects. On the west coast, EPRI has conducted detailed tidal stream energy feasibility studies on three locations: Golden Gate (San Francisco, CA), Tacoma Narrows (Tacoma, WA) and Knik Arm (Anchorage, AK). These feasibility studies include selection of available technologies, location criteria and financial models. On the East coast, EPRI tidal energy feasibility studies have been completed for four areas in the Northeast area; Muskeget Channel, MA and Western Passage, ME in the United States and Canadian locations at Minas Basin, NS and Head Harbour Passage, NB. There are two American companies with active tidal energy projects, Verdant Power and Underwater Electric Kite (UEK). Verdant has a demonstration project in New York's East River,

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[82] "$8 million support for tide power," *The Dominion Post*, December 12, 2006, http://www.stuff.co.nz/stuff/0,2106,3896680a11,00.html, accessed December 2006

[83] Hydro Technology Ventures, "Wave power units to Portugal," Hydro Technology Ventures website, http://www.hydro.com/en/press_room/news/archive/2006_03/wavepower_portugal_en.html#, accessed January 2007

and UEK has a project at Indian River Inlet, Delaware. Verdant's East River demonstration project became operational in December 2006 and is supplying part of the power for Roosevelt Island.[84] Refer to this paper's Technology section for more information on the devices used by these companies.

Denmark

Denmark has been involved in wave energy technology development since the 1980s.[85] A member of the International Energy Agency – Ocean Energy Systems (IEA-OES) executive committee, Denmark has been taking a leadership role in facilitating the development of wave energy devices and technology. There are a number of wave energy device developers working in Denmark and sea tests are proceeding, notably with the Wave Dragon and Wave Star technologies.[86]

Norway

Also a member of the IEA-OES executive committee, Norway has been active in supporting and promoting the advancement of ocean energy technology. The Norwegian government has two programs to provide support for renewable energy projects, including ocean energy. Pilot projects in both wave and tidal energy are planned. Norwegian projects include shore based and platform wave energy generation devices, and the first phase of a 10 MW full scale wave farm project using the FO^3 wave energy device is expected to be installed in 2007. Plans are in place to develop and build the Morild tidal energy demonstration project based on turbines suspended below a floating structure.[87]

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[84] Beth Fertig, "Tidal Energy Used for Electric Power," *WNYC New York Public Radio*, December 31, 2006, http://www.wnyc.org/news/articles/71358, accessed January 2007
[85] Kim Nielsen, "Development of Ocean Energy in Denmark" presentation at Canada & the World of Ocean Energy Symposium, May 4 - 5, 2006, http://www.oreg.ca/docs/May%20Symposium/Nielsen.pdf, accessed February 2007
[86] Kim Nielsen, "National Ocean Energy Activities - Denmark" presentation at 11th IEA-OES meeting Lisbon, Portugal, November 14-15, 2006, http://www.iea-oceans.org/_fich/4/DK.pdf, accessed February 2007
[87] Petter Hersleth, "Recent developments in Norway" presentation at 11th IEA-OES meeting Lisbon, Portugal, November 14-15, 2006, http http://www.iea-oceans.org/_fich/4/Norway.pdf, accessed February 2007

Tidal Power Organizations

Several organizations have formed that are dedicated to the advancement of alternative energy in general and ocean energy in particular. These organizations provide a valuable service by conducting research, hosting symposia and acting as repositories for information on ocean energy. The following is a review of four of these organizations and their activities.

Electric Power Research Institute (EPRI)

The Electric Power Research Institute (EPRI) was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.[88] EPRI's mission statement includes helping to chart the course to a sustainable energy future by identifying the technology needed to transform the electrical system.[89]

To this end, EPRI has formed a division dedicated to ocean energy, both wave energy and tidal stream energy. On the tidal stream side, EPRI has created the Tidal In Stream Energy Conversion Project (TISEC). TISEC has conducted a number of studies that look at various locations around the United States and their potential for tidal stream power generation. These studies have investigated which generation technologies are most suitable for each location and produced financial models. The studies have examined costing models based on both demonstration and commercial installations. The TISEC studies have found that tidal stream power generation on a commercial scale can produce energy at a cost only slightly higher than other forms of energy generation, and could be a valuable addition to the US west coast energy portfolio.[90] Development of tidal stream generation technology has the potential to create a brand new industry and the associated economic benefits. As Roger Bedard, the EPRI ocean

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[88] EPRI, "Corporate Overview – About the Electric Power Research Institute," EPRI website, http://my.epri.com/portal/server.pt?space=CommunityPage&cached=true&parentname=CommunityPage&parentid=2&in_hi_userid=2&control=SetCommunity&CommunityID=200&PageID=-200, accessed December 2006

[89] EPRI, "Introducing Electric Power Research Institute," EPRI website, http://my.epri.com/portal/server.pt?Product_id=000000000001014423, accessed December 2006

[90] EPRI, "060426 Final West Coast Tidal Briefing," EPRI website, http://www.epri.com/oceanenergy/attachments/streamenergy/briefings/060426_Final_West_Coast_Tidal_Briefing.pdf, accessed December 2006

energy leader, says "A small investment today might stimulate an industry which may employ thousands of people and generate billions of dollars of economic output while using an abundant and clean natural resource."[91]

International Energy Agency – Ocean Energy Systems (IEA-OES)

The International Energy Agency (IEA), based in France, was formed during the oil crisis of 1973 – 1974 and is comprised of 26 member countries. The IEA acts as policy advisor to its member countries and promotes reliable, affordable and clean energy for the world's consumers. At the 2005 G8 meeting, the IEA was asked for strategic advice for a clean, sustainable and clean energy future.[92] Promoting safer, more efficient technologies is a major goal of the IEA, as is its work on policies and technologies to reduce greenhouse gas emissions.[93] The IEA also provides analysis of long term energy trends through its World Energy Outlook publication.

A division of the IEA has been formed dedicated to Ocean Energy Systems (IEA-OES) to enhance international collaboration to make ocean energy technologies a significant energy option in the mid-term future. Through the promotion of research, development, demonstration and information exchange and dissemination, the Agreement's objective is to lead to the deployment and commercialization of Ocean Energy Technologies.[94] The IEA-OES promotes international cooperation by organizing and participating in symposia relating to the development of ocean energy technology. The presentations made at the Executive Committee meetings are published on the IEA-OES website and these are a tremendously valuable resource for the member countries and are accessible to the public. Country reviews, which describe the ocean energy situation in fourteen member countries, are available from the 11th executive committee meeting.[95]

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[91] Roger Bedard, "060426 Final West Coast Tidal Briefing," EPRI website, http://www.epri.com/oceanenergy/attachments/streamenergy/briefings/060426_Final_West_Coast_Tidal_Briefing.pdf, accessed December 2006

[92] IEA, "What is the International Energy Agency," IEA website, http://www.iea.org/journalists/faq.asp, accessed December 2006

[93] IEA, "What does the IEA do?," IEA website, http://www.iea.org/journalists/faq.asp, accessed December 2006

[94] IEA-OES, "About IEA-OES," IEA-OES website, http://www.iea-oceans.org/about/index.htm, accessed December 2006

[95] IEA-OES, "Presentations," IEA-OES website, http://www.iea-oceans.org/presentations/index.htm, accessed December 2006

Ocean Renewable Energy Group (OREG)

The Ocean Renewable Energy Group (OREG) is a collaboration between industry, academia and government formed to mobilize proven Canadian energy project implementation experience, together with new and emerging ocean technologies, to lead an effort to ensure that Canada is a leader in providing ocean energy solutions to a world market. OREG is a Canadian national organization headquartered in British Columbia.[96] The OREG website is a tremendous resource, with a great deal of information on ocean energy activities in Canada and internationally. OREG was formed in 2004 and has hosted symposia in 2005 and 2006 that attracted presenters from around the world. The presentations from these symposia are posted on the OREG website and are publicly accessible.

Some of OREG's stated goals are:

- to represent the interests of the Canadian ocean energy community with regard to the development of policies,
- supporting the industry by facilitating the research, development and deployment of projects,
- forming strategic alliances with other organizations,
- to promote discussion, forums, and workshops in an effort to increase public awareness and understanding, and
- to lead the way towards commercialization of ocean energy in Canada.[97]

British Wind Energy Association (BWEA)

The British Wind Energy Association (BWEA) was formed in 1978 and is the leading renewable energy trade association in the UK, acting as a central information point for its members and as a lobbying group. Its initial focus was the wind industry but has expanded its purview in recent years to include ocean energy. The association hopes to use its experience in championing wind energy to commercial implementation to help ocean energy down the same path.[98]

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[96] OREG, "Welcome to Ocean Renewable Energy Group," OREG website, http://www.oreg.ca, accessed December 2006
[97] OREG, "About," OREG website, http://www.oreg.ca/about.html, accessed December 2006
[98] BWEA, "About BWEA," BWEA website, http://www.bwea.com/about/index.html, accessed December 2006

Sites In British Columbia

In 2002, Triton Consultants completed a study for BC Hydro that identified potential tidal resource sites in BC, the 2006 study built on those results. Triton identified 89 sites on the BC coast with potential tidal resources greater than 1 MW.[99] The great advantage of many of these sites is their relative proximity to the grid, often within a few kilometers – in some cases, the tidal resource is virtually adjacent to a grid connection point.

Marine traffic is a concern along the BC coast and so this has the effect of limiting the feasibility of developing some tidal power resources or limiting the devices that might be used. Heavy marine traffic may prevent the positioning of barges required to install tidal energy generation devices. Large ship traffic requires minimum clearance to turbines below the surface, generally accepted as 15 meters. Some suitable channels may not be of sufficient depth to allow both tidal power generation and ship traffic. Finally, some channels are so deep, with such powerful tidal flows, that installation of tidal power generator(s) is not possible with current technology and available equipment.

Notwithstanding the above noted limitations, the BC coast is richly endowed with tidal resource sites that are suitable for development. The nature of the coastal geography and hydrology means that there are many narrow channels with fast, powerful tidal flows. This creates sites with high power density. In Triton's 2006 report there is a ranking of sites by power density. Sixteen of the top twenty-five sites are in BC, including the top three.[100] These are sites where there is a good opportunity to extract energy from the tidal stream.

Triton's report describes a characteristic of tidal flows in BC that are especially suitable for power generation: "In British Columbia, some of the highest velocity tidal current flows in Canada occur through the passages between Strait of Georgia and Johnstone Strait. The tidal range is moderate (5 m), but the tides from the Pacific through Johnstone Strait are roughly 180 degrees out of phase with the tides in Strait of Georgia entering south of Vancouver Island."[101]

This is the area that includes Stuart Island. Of the top twenty-five power density sites mentioned above, five of those are in the waters surrounding Stuart Island. The picture below illustrates the

[99] Cornett, *Inventory of Canada's Marine Renewable Energy Resources* p. 83
[100] Tarbotton and Larson, *Canada Ocean Energy Atlas (Phase 1)* p. 16
[101] Ibid. p. 10

narrow channels into which the tidal stream must be compressed, resulting in the powerful currents that create the tidal resources found between Vancouver Island and the mainland of BC.

[102]

[102] Image source: Google Earth, http://earth.google.com/

Stuart Island area

Stuart Island is in a remote location, far from the nearest city. It is a rugged place, with rocky islands poking through the water's surface that only hints of the powerful currents below. The waters of Cardero Channel around Stuart Island are tremendous tidal power resources. These resources, along with the off-grid location, are the reason the Stuart Island area was chosen for this study.

First Nations people have been living in the area for centuries, long before electrical power was invented. The powerful ocean currents that make the waters of Cardero Channel a prime habitat for fish, sea birds and marine mammals make the islands surrounding the channel a prime place for people to live.

Nowadays, electrical power has made life easier in the Stuart Island area – modern conveniences like electric lighting, power for refrigeration, telephone and communications are now available for residents. Resorts have sprouted up around Cardero Channel and there are more visitors each year. Presently, all the electrical power is produced by diesel generators (gensets), so the price paid for these conveniences of modern life are air pollution, noise pollution and the potential for water pollution. Each resort has one or more gensets to provide electricity for their guests and most of the residences have a small generator on their property.

Cardero Channel, in the subject area, is surrounded by Stuart Island to the east, Sonora Island to the southwest, Dent Island to the west and the mainland of BC to the north. Resorts, permanent residences and summer vacation homes dot the shoreline. Most of the residential dwellings are on the west side of Stuart Island. In the past, the community was centred on Big Bay, where there was a public marina, small general store and post office. The marina was purchased by a private company and the public facilities were closed, so the community currently lacks a focal point. Some of the resident's families have lived in the area for generations, after it was first inhabited by white settlers about 80 years ago. At present, Canada Post records show there are twelve permanent residences in the Stuart Island area.

At the time of writing there were ten resorts, some private and some public. They range in size from about twelve guests to more than a hundred. As with the residences, most of the resorts are located on the west side of Stuart Island, but there are a couple on the mainland shore and

the largest resort by far is on Sonora Island. Sonora Resort is the largest power user in the area. Most of the visitors to the area come in the summer, when the weather is fairest and the ocean calmest. Often the visitors come in pursuit of trophy Spring Salmon and guided fishing trips are the mainstay of the resorts. However, ecotourism is a growing business in the area. Wilderness areas are a short boat ride away, and ecotourists can go on expeditions in search of eagles, grizzly bears, sea lions and if they are lucky, orcas.

Ecotourism

Ecotourism represents good growth potential for the Stuart Island area, for three main reasons:

- It can generate revenue from non-fishing visitors accompanying fishermen,
- It does not require more infrastructure investment, and
- It can extend the busy season for the resorts, even into winter.

A large proportion of the visitors to Stuart Island come during salmon fishing season, from late June until mid September. Resorts are usually fully booked in the peak of the salmon season, so revenue growth from fishing would require adding capacity (rooms). However, some visitors are accompanying fishermen but have little interest in fishing. For these guests, ecotourism provides an opportunity to enjoy the wilderness setting to a greater extent. Most resorts are offering some ecotours now. Promoting ecotourism can enable resorts to fill more rooms in the off-peak weeks at the beginning and end of the prime fishing season.

The largest opportunity that ecotourism presents to the Stuart Island area is by extending the time the resorts are open each year. Earlier in the summer before the main salmon runs have arrived, and later in the fall when most of the fish have passed through are times when ecotourism could be emphasized. Adding a few weeks to the season would use existing resort infrastructure and provide additional return on investment from assets that are idle for a large part of the year. It is possible that opening during the winter season could be a viable way to maximize the use of these assets. Resorts along the west coast of Vancouver Island have established a seasonal business with visitors who come to witness the power of the Pacific Ocean during storm season. The resorts at Stuart Island could do this too.

Power Situation in the Stuart Island area

It is difficult to accurately determine exactly how much diesel fuel is used at Stuart Island and how much money is spent on diesel fuel for power generation. However, estimates can be prepared using confidential information provided by some resorts. At this time, precise information about the amount of power used is impossible to gather, as the gensets at the resorts run at different outputs depending on the number of guests and the weather conditions. Estimates can be prepared, though, using specifications from genset manufacturers to calculate estimated power generated from the amount of fuel used. The actual power usage, therefore, is a source of uncertainty for this study.

Information was received from 7 of the 10 resorts, representing about 90 % of the total generating capacity in the Stuart Island area. Total estimated generation capacity, total cost of fuel and total amount of diesel fuel used were extrapolated from this information to include all resorts, using resorts of similar size to assemble the information. For full details on the calculations, refer to the Financial Analysis – Diesel Power section.

Cost of Diesel Generation

Based on the data collected, it is estimated that in 2006:

- The cost of diesel fuel for power generation in the Stuart Island area was $ 1,250,000
- About 1,450,000 litres of diesel fuel was used to generate electrical power
- Total generation capacity was approximately 1,950 KW
- Effective generation capacity was about 1,300 KW in summer and 600 KW in winter
- Total power generated was about 4,640,000 KW hours
- 529 KW average power produced in the Stuart island area in 2006.
- The cost of the electricity currently being produced by the diesel generators at Stuart Island is about 29 cents per KWh.

Diesel fuel, along with Propane and Gasoline, is delivered to the resorts and residents of the Stuart Island area on a monthly basis by Inlet Transportation out of Campbell River. This scheduled barge service also brings other supplies to communities along the BC coast, from Vancouver to Prince Rupert.

Non-monetary costs

There are a number of non-monetary costs to the diesel power generation in the Stuart Island area. The most obvious one is the air pollution created by the emissions from the diesel generators' exhaust gases. Diesel exhaust contains a number of different gases: carbon monoxide, oxides of nitrogen, carbon dioxide and water vapour are the main constituents. Other components of diesel exhaust are actually the ones people notice the most – unburnt fuel from incomplete combustion and sulphur compounds from fuel impurities cause most of the odour, and soot particles (carbon) cause most of the visible smoke.

Lately, the world's attention has been focused on greenhouse gases and the effect they are having on global warming. Carbon dioxide (CO2) has been identified as one of the major culprits causing global warming, with atmospheric CO2 levels having risen sharply over the last century. Exactly how much of that CO2 is from human activity is a matter of vigorous debate that will not be discussed here, but there is no doubt that limiting emissions and pollutants makes sense. According to the US Environmental Protection Agency (EPA), the amount of CO2 emissions from a gallon of diesel fuel is 10.1 kg,[103] which converts to 2.67 kg / litre. So the 1,450,000 litres of diesel fuel used for power generation in the Stuart Island area in 2006 contributed about 3,871,500 kg of CO2 emissions.

Another non-monetary effect of diesel power generation is noise pollution. It is ironic that to visit a place as quiet as Stuart Island, people have to listen to the background noise of a genset.

The risk of a diesel spill during transportation or storage is an additional non-monetary aspect of diesel power generation. A serious spill could cause severe environmental damage to the waters of Cardero Channel.

A clean power solution for the Stuart Island area would reduce or eliminate the negative environment effects described above and improve the quality of life for residents and visitors. And it would also create an unprecedented opportunity for promotion and marketing of the resorts in the Stuart Island area. Clean power would enhance the area's reputation as a location for ecotourism and provide an additional impetus to the growth of ecotourism in the area.

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[103] US Environmental Protection Agency, "Emission Facts: Average Carbon Dioxide Emissions Resulting from Gasoline and Diesel Fuel," EPA website, http://www.epa.gov/otaq/climate/420f05001.htm accessed January 2007

Location Criteria - general

The most important consideration for a tidal power generation site is a suitable tidal power resource. Triton Consultants has identified 89 locations on the BC coast with tidal resources of 1MW or more. The diagram below shows a segment of the BC coast, centred on mid Vancouver Island, including Discovery Passage and Seymour Narrows. The Stuart Island area is in the top right area, with several overlapping red dots indicating the presence of large tidal resources.

Figure 8: Potential Sites – Central Vancouver Island

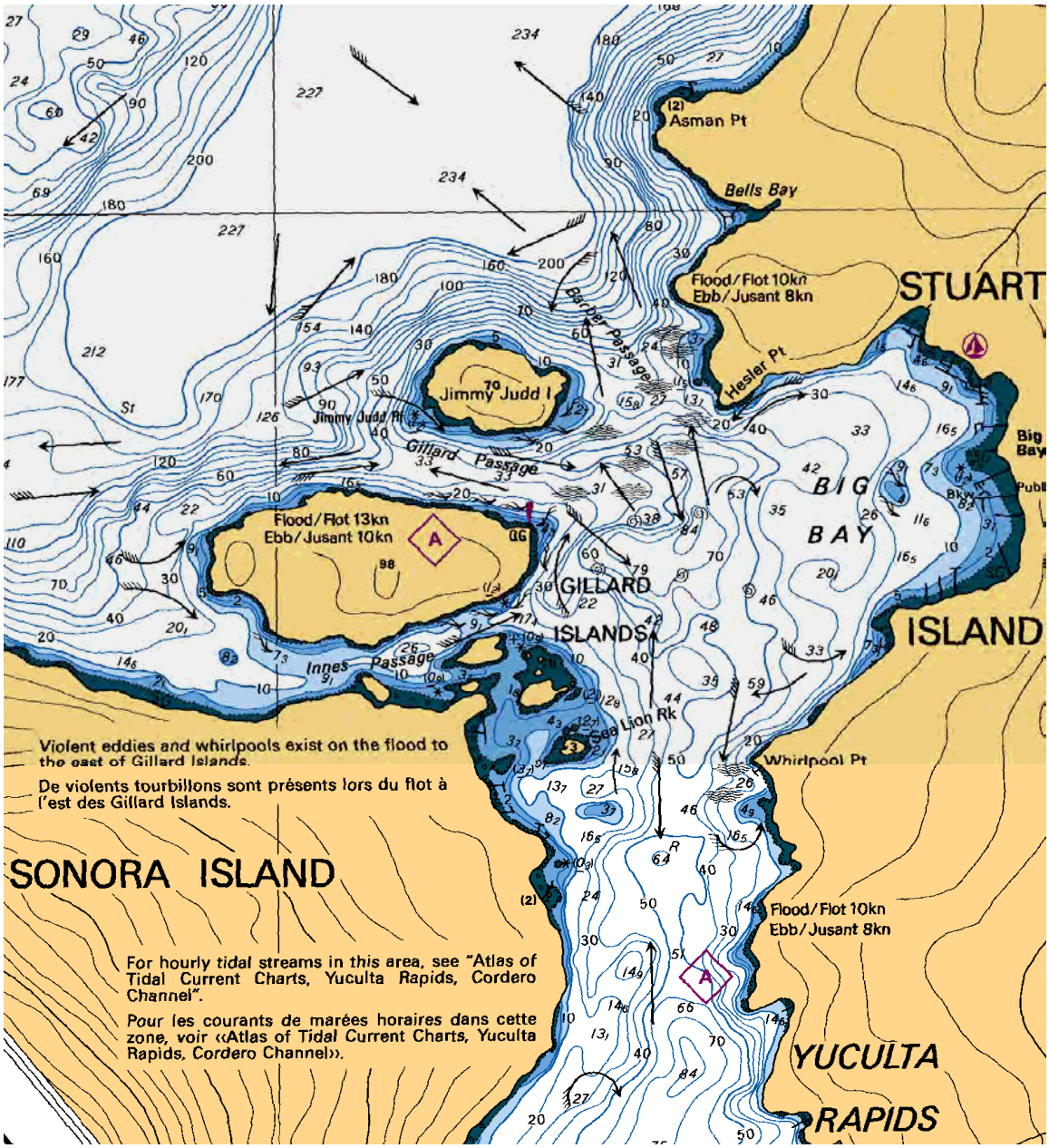
[104]

As previously mentioned, flow rate is a vitally important aspect of tidal power generation – the more current flow, the better. Peak current flows in Cardero Channel near Stuart Island are in the 8 to 14 knot range (4 to 7 m/s) so the channels and rapids certainly have enough current velocity for tidal power generation, in light of Triton Consultants' threshold of 2 m/s. See below for a marine chart of the area showing the tidal currents.

A third consideration for site selection is proximity to the grid, or in the case of an off-grid application, is proximity to the community. The major resorts in the area are centred around Big Bay, on the west side of Stuart Island, and immediately across the channel on Sonora Island. Proximity to four potential tidal power sites is very close, with Big Bay and Sonora Resort virtually adjacent to the resources on opposite sides of the channel.

[104] Triton Consultants, Green Energy Study for British Columbia. p. 19

Water depth requirement is dictated by two factors, the size of the proposed device(s) and the marine traffic. Marine traffic is frequent through the passages of Cardero Channel, but the vessels are not particularly large or with very deep drafts. EPRI studies mentioned a requirement for a minimum of 5 metres clearance between the low water level and the turbine. There are a number of sites in the Stuart Island area that can easily meet this requirement. The marine traffic, however, would eliminate surface piercing devices from use in the area.



[105]

[105] Canadian Hydrographic Service, chart 3543

Location Criteria - Specific

As noted in the previous section, the waters of Cardero Channel around Stuart Island are tremendous tidal power resources. Of particular interest are Gillard Passage (referred to as Gillard 1 by Triton), Barber Passage (Gillard 2), Innes Passage (Gillard 3) and Yaculta Rapids. Refer to the chart on the previous page for locations. These resources, along with the off-grid situation, are the reason the Stuart island area was chosen for this study.

The four locations mentioned were considered for this study; they represent a cross section of tidal resources on the BC coast. Yaculta Rapids is a deep, relatively narrow channel with powerful currents that make it a sizable tidal power resource. Gillard and Barber Passages are smaller, moderately deep channels with higher current velocities. Innes Passage is much smaller and shallower than the others, still with significant current flows and the advantage of no commercial marine traffic.

Data excerpted from Triton Consultants report[106]

Name	Mean maximum depth average current speed	Width	Average Depth	Mean Potential Power
Yaculta Rapids	4.12 m/s	539 m	28 m	78.7 MW
Gillard Passage (Gillard 1)	4.74 m/s	237 m	16 m	43.3 MW
Barber Passage (Gillard 2)	3.71 m/s	393 m	18 m	23.2 MW
Innes Passage (Gillard 3)	3.71 m/s	92 m	5 m	3.2 MW

The average depth figures shown in the table can be misleading; deeper areas exist in the centre of the channel and/or near the channel as can be seen on the chart. Site selection would have to be determined according to the overall height above the seabed for a given device and the anticipated clearance for marine traffic.

[106] Triton Consultants, Green Energy Study for British Columbia p. 21

Seabed conditions are unknown, and this represents considerable uncertainty. The powerful tidal currents in the passages and rapids of Cardero Channel mean that tremendous forces will be brought to bear on any power generation device that might be installed there. The anchoring method will be critical to the success of the endeavor. Seabed conditions will determine both the anchoring method and the manner in which the device will be anchored to the bottom of the channel. For example, if the seabed is granite (as is likely) then holes for anchors will have to be drilled from the surface. What are the limitations and availability of the equipment necessary to hold position accurately and drill holes in solid rock in conditions where the tidal currents are not just strong, but also constantly changing in velocity? At present, there are no answers available to those questions. The recent installation at Race Rocks has shown that a tidal turbine can be successfully installed in BC waters. However, this installation does not shed much light on installation of a turbine in the waters near Stuart Island, where the current velocities are much greater and the channels are narrow.

The rationale for choosing a location from the four channels near Stuart Island must include an examination of marine traffic in the area. It makes sense that Yaculta Rapids and the widest of the channels between Stuart and Sonora Islands (Barber Passage) would not be able to be blocked for a few weeks while a turbine or turbines were installed. A full size turbine is too large for Innes Passage, so Gillard Passage is the best choice for an investigation into the possibility of installing tidal power generation device(s) at Stuart Island. A study would have to be made of the extent and nature of marine traffic through Gillard Passage and the effect that a turbine installation closure would have.

Environmental considerations are an important aspect of site selection, and a full review would need to be done as part of the site selection process. At this time, it is unknown what the effect on the ecosystem would be if a portion of the tidal energy were removed. In its feasibility studies, EPRI has suggested that a maximum of 15% of the total tidal energy from an area is appropriate.[107] A possible effect is a slowing of the tidal flow through the channel, resulting in increased sedimentation. A large change in the speed of volume of water through the channel could cause a correspondingly large change in the channel's ecosystem.

[107] EPRI, "Instream Tidal Power in North America – Environmental and Permitting Issues," http://www.epri.com/oceanenergy/attachments/streamenergy/reports/007_Env_and_Reg_Issues_Report_060906.pdf accessed February 2007

A wide variety of fish and marine mammals live in or pass through the waters of Cardero Channel. No studies have yet been completed on the effects that tidal turbines have on marine life. Verdant Power, as part of its project in the East River, is conducting a comprehensive study using an array of sensors to determine the effect on fish. The study has not been completed and no data is yet available, but preliminary indications are that fish not adversely affected. In fact, fish and diving birds (cormorants) have been observed simply swimming around the turbine. [108]

Cardero Channel is home to many different marine birds and mammals and there is no available evidence to suggest how a tidal power turbine might affect them. There is a large population of resident seals and sea lions; dolphins and orcas transit the area. Diving birds such as cormorants, grebes, loons and ducks frequent the area. Until more turbines are in the water, information cannot be gathered on how marine birds and mammals might react to a tidal power installation.

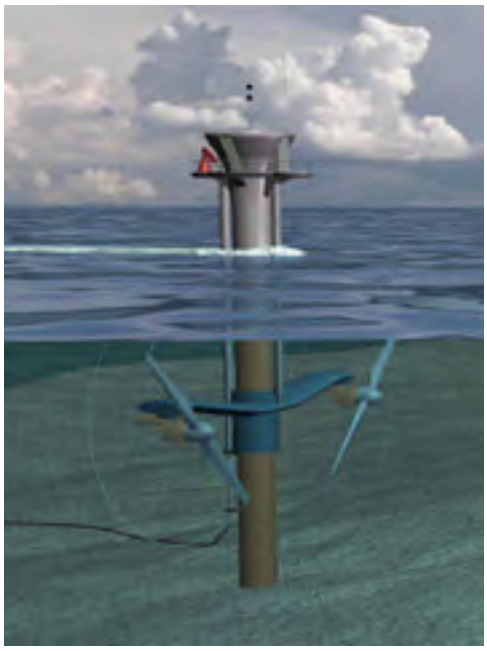
[108] Trey Taylor, Verdant Power, telephone interview with author, February 13, 2007

Technology

Tidal power generation technology is in its infancy. There are many developers of tidal power generation equipment and a myriad of designs, limited only by the designers' imaginations. The devices that are progressing fastest toward commercialization are turbines. Even within the confines of the turbine group, though, there are many different devices that are being developed. The following is a review of some of the leading technologies. Images in this section are from company websites.

Marine Current Turbines

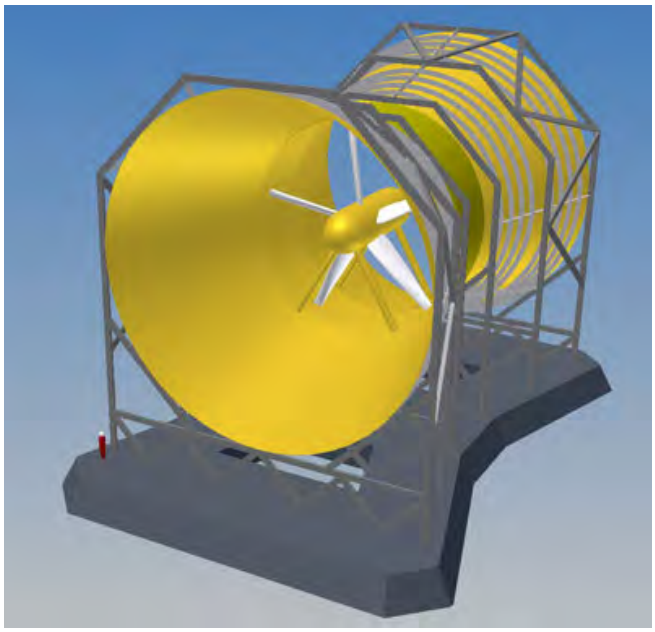
Until very recently, Marine Current Turbines (MCT) held the distinction of being the only company that had produced and installed a near-commercial scale tidal power turbine. The Seaflow project was installed in May 2004 off the coast of Lynmouth, Devon. This 300 KW device has worked very well over the last three years – well enough for MCT to move forward to Seagen, a commercial size unit (1.2 MW) that will be installed near Strangford Narrows in 2007. The Seagen device is completed and sitting on a dock waiting for installation. MCT uses an open axial flow rotor because "it is the most efficient and cost-effective form of kinetic energy converter. If this sounds like a bold statement it should be noted that every conceivable form of rotor, open and shrouded, has been tried for wind turbines and the technology has converged on the most cost-effective technical solution, namely a tubular tower carrying a nacelle with an upwind pitch-regulated axial flow rotor. Although water kinetic energy conversion introduces some different design issues, the basic physical principles are the same as for wind turbines." [109]



[109] Peter Fraenkel, "Marine Current Turbines tidal turbine developments: the development of an entirely new energy conversion system ," paper presented at World Maritime Technology Conference 2006, London, UK, March 6 – 10, 2006

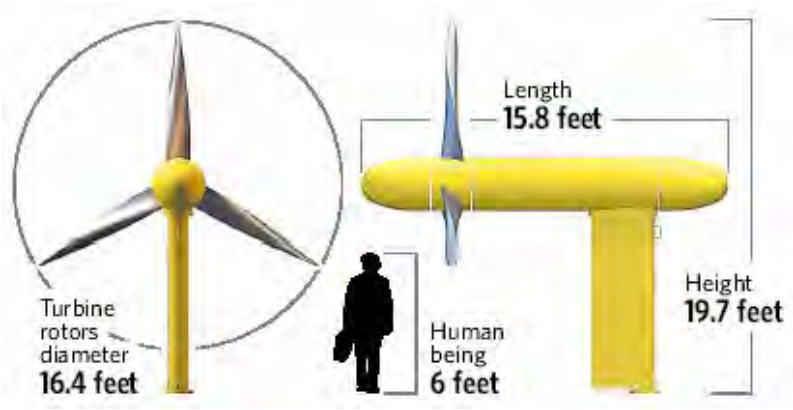
Lunar Energy

Lunar Energy is a UK based tidal energy device developer. Lunar's design features a bidirectional concentrator cone structure with the turbine and power conversion components contained in a removable centre mounted cassette. The picture at right gives a good sense of the size of tidal turbines – note the human figure in the bottom left corner. In 2005, Lunar completed proof of concept testing in the laboratory and is currently in the process of building a full scale 1 MW device that will be installed at the EMEC facility at Orkney in late 2007 or early 2008. When completed, this will be only the second full size, commercial scale tidal energy generator in the world. Lunar Energy is a participant in the BC tidal energy industry as it holds an Investigative Use Permit for an area of Discovery Passage, and forecasts activity at that site near Seymour Narrows to begin in late 2009.



Verdant Power

Verdant Power is a US based company that has developed and tested several tidal stream turbine devices. The company settled on a design that uses a three bladed horizontal axis axial flow turbine.[110] In December 2006 the first turbine was installed in New York's East River. The picture at right shows the nature and scale of the device.[111] It is supplying power to an area of Roosevelt Island now.

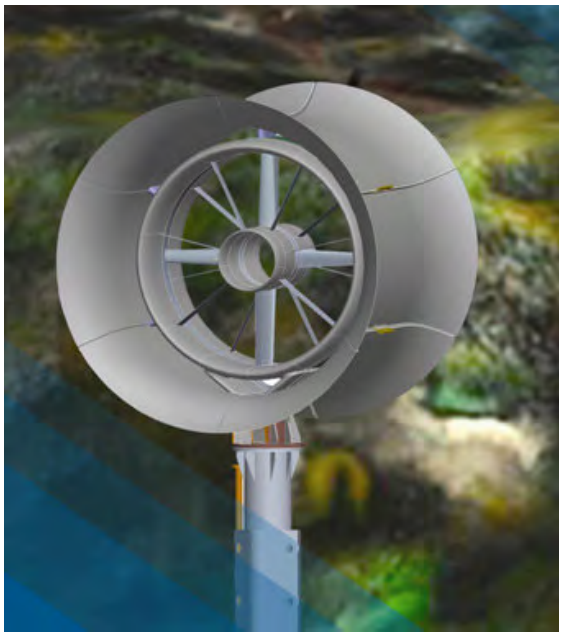


[110] Verdant Power, "Background of Verdant Power," http://www.verdantpower.com/aboutus/history.html, accessed January 2007
[111] "Planning the next wave," *Newsday* (May 30, 2006): A26 Courtesy of Trey Taylor

If initial success is confirmed a further five turbines will be installed. These turbines are rated at 35 KW, but plans are to scale up the device to units having a capacity up to 250 KW and eventually up to 1 MW. Of particular note is the study Verdant Power is doing with regard to the impact tidal energy turbines have on fish. Verdant Power has spent two million dollars to install an array of sensors to capture evidence of safe fish passage at the East River site. Preliminary observations indicate that fish are swimming around the turbine.[112]

Clean Current

Clean Current's tidal turbine generator is a bi-directional ducted horizontal axis turbine with a direct drive variable speed permanent magnet generator. "This proprietary design delivers better than 50 per cent water-to-wire efficiency, a significant improvement over competing free stream tidal energy technologies. Operability is enhanced by a simple design that has one moving part - the rotor assembly that contains the permanent magnets. There is no drive shaft and no gearbox. The turbine generator has a design life of 10 years (major overhaul every 10 years) and a service life of 25-30 years." [113]



Clean Current entered into a demonstration project with Pearson College at Race Rocks, BC with major funding provided by Encana.[114] A one quarter scale, 65 KW turbine was installed on September 27, 2006 and is now producing power for the lighthouse, weather station and other infrastructure on the island. As this power plant is not connected to the electrical grid, banks of batteries are used to store electricity for times when the tidal stream generator is not producing power, such as slack tide.[115]

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[112] Trey Taylor, Verdant Power, email correspondence with author, January 29, 2007
[113] Natural Resources Canada, "Clean Current Tidal Power Demonstration Project at Race Rocks, BC," Natural Resources Canada website, http://www.cleanenergy.gc.ca/international/project_e.asp?item=61, accessed January 2007
[114] Encana, "Pearson College - EnCana - Clean Current Tidal Power Demonstration Project at Race Rocks," Encana website, http://www.encana.com/responsibility/eif/fundedprojects/P1162484703969.html, accessed January 2007
[115]Russell Strothers, Clean Current, telephone interview with author, January 8, 2007

OpenHydro

OpenHydro is a tidal energy company based in Ireland that uses a unique design called the Open-Centre Turbine. The Open-Centre Turbine, with just one moving part and no seals, is a self-contained rotor with a solid state permanent magnet generator encapsulated within the outer rim, minimising maintenance requirements. Open-Centre Technology is unique and covered by a suite of worldwide patents.[116] In January 2007 was the first developer to install a tidal turbine at the EMEC facility at Orkney. As can be seen at right, the test unit is mounted between two monopiles allowing it to be raised and lowered easily for testing. Commercial installations will be deployed on the seabed using a gravity base, out of sight beneath the surface of the sea.[117]

In January 2007, OpenHydro was selected by Nova Scotia Power to be the provider of the tidal stream power generation device at a new demonstration project in the Bay of Fundy. OpenHydro's technology was chosen because of its proven experience, simple robust design and low impact on the environment. If the demonstration project is successful, Nova Scotia Power plans to develop the largest tidal stream power generation facility in the world.[118]

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[116] OpenHydro, "technology," OpenHydro website, http://www.openhydro.com/technology.html , accessed January 2007

[117] OpenHydro, "technology: installation," OpenHydro website, http://www.openhydro.com/techInstall.html, accessed January 2007

[118] "Nova Scotia Power Takes Another Step Towards Tidal Power Pilot Project," Nova Scotia Power press release (Halifax, NS, January 12, 2007). From Nova Scotia Power website, http://www.nspower.ca/about_nspi/in_the_news/2007/01122007.shtml, accessed January 2007

New Energy

New Energy is a Calgary based developer of tidal energy technology. New Energy's EnCurrent technology builds on work carried out by the National Research Council on a vertical axis hydro turbine. Based on the design of the Darrieus wind turbine, commonly referred to as an egg-beater windmill due to the shape of its blades, the EnCurrent turbine is able to extract 40% to 45% of the energy in the water moving through it. One of the unique properties of the Darrieus Turbine design is that it is able to capture the energy from the water irrespective of the direction of the current. This property enables the EnCurrent turbine to harness the energy contained in both flood and ebb tides.[119] The EnCurrent design allows for various configurations of the turbine including overhung, beam style, center shaft or end plate supported, fixed blade or variable pitch.[120] New Energy has working devices installed in two small scale outflow demonstration projects in Alberta. New Energy is involved in the Canoe Pass demonstration project so it is making an active contribution to the development of the BC tidal power industry.

Underwater Electric Kite

Underwater Electric Kite (UEK) is an American company that is doing development and testing of tidal stream turbines. UEK uses two counter rotating turbines and a patented ducted turbine design that is enhanced by a flared skirt that creates a low pressure zone directly behind the turbine. The company claims this design has the potential to achieve overall efficiency of up to 57%. The company has worked with the University of Manitoba to study the performance of the turbine and is planning to supply turbines for an installation in Africa. A proposed project at Indian River Inlet in Delaware is at the permitting stage.[121]

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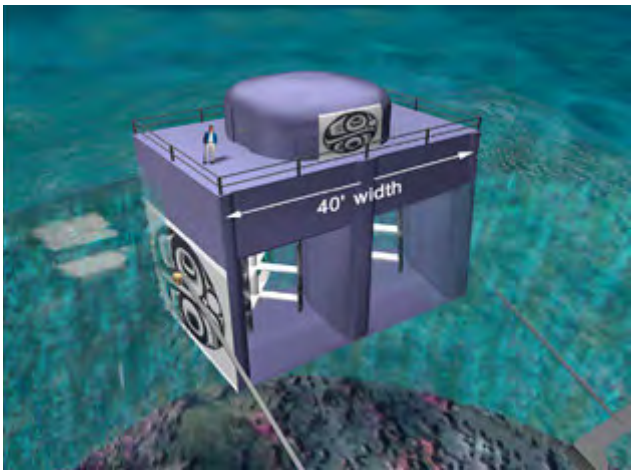
[119] New Energy Corporation, "Technology: Overview," New Energy Corporation website, http://www.newenergycorp.ca/technology_overview.htm, accessed January 2007
[120] New Energy Corporation, "Technology: How It Works," New Energy Corporation website, http://www.newenergycorp.ca/technology_how_it_works.htm, accessed January 2007
[121] Philippe Vauthier, "Kite soars to new depths," *International Water Power and Dam Construction*, March 16, 2006, http://www.waterpowermagazine.com/storyprint.asp?sc=2034904, accessed January 2007

Gorlov Turbine

The rights to the Gorlov turbine are held by GCK Technologies, a US company. The Gorlov Helical Turbine was specifically designed for hydroelectric applications in free flowing low head water courses. Some of the characteristics of the Gorlov turbine are that it rotates in the same direction, independent of water flow direction and can be assembled vertically, horizontally or in any other cross-flow combination using a common shaft and generator for an array of multiple turbines. The modular design offers great flexibility, which can simplify and reduce the construction, expansion and maintenance costs of a power generating facility.[122] A proposal for a floating power plant at Ulmoldok, Korea uses the Gorlov turbine.

Blue Energy

Blue Energy is a Canadian company based in Vancouver. The key component of the Blue Energy Power System is the Davis Hydro Turbine, which is based on the undeveloped 1927 patent on a vertical axis windmill by French inventor Georges Darrieus. Blue Energy's predecessor, Nova Energy Ltd., successfully built and field-tested two experimental test units and three prototype Davis Hydro Turbines through a $1.3 million, 10-year collaborative R&D program with the National Research Council of Canada.[123] The Blue Energy Ocean Turbine acts as a highly efficient underwater vertical-axis windmill.



Four fixed hydrofoil blades of the Blue Energy Ocean Turbine are connected to a rotor that drives an integrated gearbox and electrical generator assembly. The turbine is mounted in a

[122] GCK Technology, "The Gorlov Helical Turbine," GCK Technology website, http://www.gcktechnology.com/GCK/pg2.html, accessed January 2007
[123] Blue Energy Canada, "Blue Energy Development," Blue Energy website, http://www.bluenergy.com/davisTurbinesptypes.html, accessed January 2007

durable concrete marine caisson which anchors the unit to the ocean floor, directs flow through the turbine further concentrating the resource supporting the coupler, gearbox, and generator above it.[124]

Water Wall Turbine

Water Wall Turbine is a tidal power turbine developer based in British Columbia. Little information is available about the device, other than it is a horizontal axis turbine. Water Wall Turbine claims that its simple design has over double the energy production per square metre than any of the competing renewable energy generation technologies.[125]

[124] Blue Energy Canada, "Blue Energy Technology," Blue Energy website, http://www.bluenergy.com/technology.html, accessed January 2007
[125] Marek Sredzki, Water Wall Turbines, email correspondence with author, November 25, 2006.

Device & Installation Details

There are many aspects to a tidal stream power generation deployment, and the device is just one of them. All of these factors must be considered together when determining the suitability for a particular site. The site itself is the most important consideration – the site characteristics will determine what type of device may be considered and what size limitations there may be. Because all tidal energy conversion devices are governed by the same principles of physics, namely area and current velocity, for the same site conditions and rated power the physical size of the units will be similar.

Triton Consultants provide the following formula for calculating the instantaneous power $P_{extractable}$ for a turbine installation[126]

$$P_{extractable} = N_{units}\eta\frac{1}{2}\rho A_{turbine}U^3$$

Where N_{units} is the number of installed units, n is the turbine/mechanical/electrical efficiency, p is the density of water (kg/m^3), $A_{turbine}$ is the turbine rotor area (m^2) and U is the instantaneous current velocity (m/s). It can be seen that power is proportional to the area swept by the turbine, so at a given site, devices that present a similar area will have similar power potential. The difference between devices, then, is the efficiency n with which the device extracts the power from the water flowing through it – this is the battleground for the device developers.

A very significant observation from the formula is the importance of current velocity to power. Because velocity is cubed in the formula, higher velocities confer an ever-greater power advantage, thus the importance of site selection.

Other factors that affect the logistics of a tidal power installation are the subsea cabling, as well as on shore transforming & power conditioning, and on-shore electricity distribution or interconnection to existing distribution.

The installation itself is a source of considerable variation. The seabed composition is an important factor in the method chosen to support or anchor the power generation device.

[126] Triton Consultants, Green Energy Study for British Columbia.

However, this is not the only consideration. The availability of equipment suitable for the installation method chosen may play a major role in determining cost or feasibility of the installation. For example, equipment may have to be brought in from far away parts of the world. The nature of the site conditions, such as current speed, narrowness of channel and marine traffic plays an important part in the determination of the cost, time and practicability of the installation.

Further discussion on costs associated with devices and installation can be found in the Financial Analysis section of this paper.

Appendix I

Storage

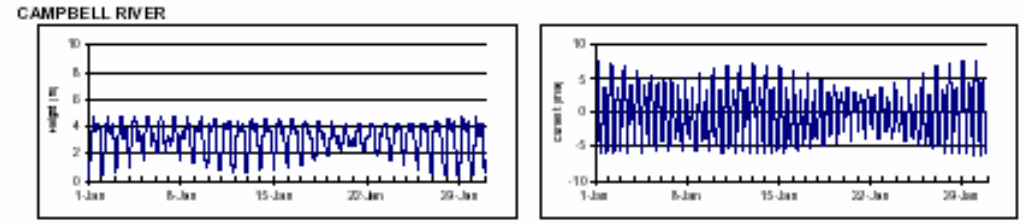
When this study began, no consideration was given to energy storage. However, as the investigation progressed, the importance of energy storage in off-grid installations became more and more apparent. This is true not just of tidal power generation, but any power being generated in an off-grid situation. Energy storage in tidal power applications, because of the continuously fluctuating power output, is a critical factor and very challenging.

A fundamental characteristic of electrical power is that the power generated must be balanced by the electrical load (power requirement of the system). This can be done by increasing the load or decreasing the power being generated. In a large system, individual increases or decreases in load or power generated can cancel one another out, resulting in a dampening effect. In the case of the North American power grid, computers in control centres strategically located across the continent monitor the grid and make the adjustments necessary to keep the grid stable.

In an off-grid system, balancing of the generation and the load is more immediate. If generated power is not being used by the system, it must be either dumped or stored. Dumped power, as the term suggests, is often wasted power. Power can be dumped into a load bank that will convert the power to heat in a manner similar to an electric baseboard heater. In some cases, this heat may be put to good use, but in other cases that heat will just be allowed to dissipate. Alternatively, generated power can be stored – for example, by charging a bank of batteries or by using excess power to do work.

Off-grid tidal power, by its nature, necessitates an efficient method of power storage. The power from a tidal generator will go to zero from two to four times a day, at slack tide. Obviously, at those times no power will be available to supply electricity to anything that draws power from the system. Conversely, peak current velocity at other times of the day may generate power far in excess of demand. So an efficient storage system that can store power at times of excess production for use during the times of low or zero production is necessary in off-grid applications. The following graphs from Triton Consultants illustrate how the height of the tide (left) and tidal current (right) fluctuate throughout a representative month. As noted in the previous section, current velocity has a major impact on power generated by a tidal stream

turbine. Hence, it can be concluded that the fluctuations in current velocity shown in the graph below represent power fluctuations.



[127]

High school physics taught the Law of Conservation of Energy, which states that energy cannot be created or destroyed, but can change its form. Energy storage in an off-grid tidal application, put simply, is changing the form of the energy from kinetic energy to potential energy. Pumping water to a higher elevation is the most straightforward example – kinetic energy from a tidal stream is used to pump water up to a higher elevation where it is stored as potential energy. Of course, it's not quite that simple; in this example, the tidal stream turbine converts kinetic energy from the water flow to mechanical energy, the generator converts the mechanical energy to electrical energy, which is used to do work to store the energy, such as powering a pump to move the water up to the higher elevation storage reservoir where it is then in the form of potential energy.

The most common type of energy storage is with batteries, a method everyone is familiar with. For example, a large bank of forklift batteries is being used at Race Rocks for energy storage. The batteries are large and heavy, making them impractical for full scale installations. Future advances in battery technology might make this type of energy storage more viable for large installations.

In the search for energy storage methods that are more efficient and less expensive, a few other methods have been proposed for tidal power applications, as follows:

- Ultracapacitors – Large capacitors might prove to be a viable method of energy storage, but at present this technology is not available off the shelf. Capacitors have the advantage of accepting a charge very quickly and are capable of being charged and discharged thousands of times without losing capacity. Advances in technology may make ultracapacitors a possibility in the future.

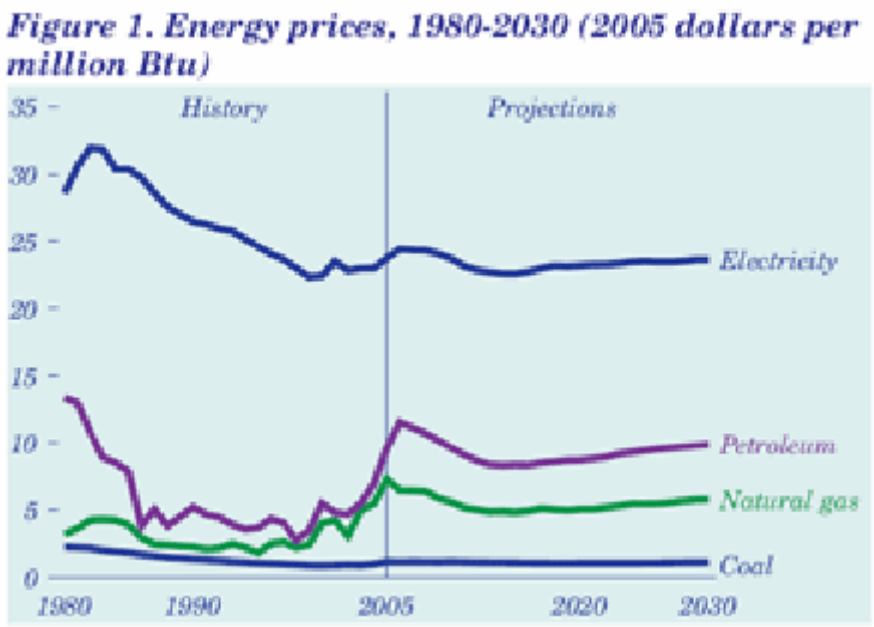
[127] Ibid., p. 13.

- Water pumping – pumping water to a higher elevation is a way to store potential energy. The water stored in a reservoir at the higher elevation can be allowed to return to the base elevation under controlled circumstances, changing the form of the energy from potential to kinetic so as to turn a turbine and generate secondary power.
- Compressed air – excess power can be used to increase air pressure in a vessel (potential energy) then released in a controlled manner when required to turn a turbine.
- Hydrogen – excess power could be used to create hydrogen, which could then be used in a fuel cell to provide power to produce electricity. This system has good future potential, but the efficiency of the system is not yet good enough for it to be viable at present. In BC there is potential for synergy between the tidal energy industry and the fuel cell industry.
- Fresh water – excess power could be used to produce fresh water, by distillation or by reverse osmosis. This would not store energy, but instead would do work to use excess energy to produce another unrelated product (fresh water) to be stored for use when required. There is an opportunity for the development of a package solution for off grid remote communities encompassing power generation and fresh water production.

Appendix I

Financial Analysis - Diesel power calculations

The cost of diesel power generation and future projections can be estimated with a reasonable level of certainty. While the past summer's price spike for petroleum products was an excellent example of the dramatic effect uncertainty can have in the marketplace, the price of oil over the long term is predicted to be quite stable. The US Energy Information Agency published its Annual Energy Outlook 2007 with projections to 2030, which predicts crude oil prices will decline slowly to just below US $50 a barrel in 2014, followed by a gradual rise to US $59 a barrel by 2030 (all figures in 2005 dollars). This is a result of new conventional and unconventional oil supply coming on stream and a prediction that OPEC will adjust production to keep oil prices in the US $50 to $60 range over the next 25 years.[128]



[129]

As a correlation, the World Bank commodity forecast indicates that the price of crude oil will decline though the next several years and in fact is predicting the average price of a barrel of oil will fall to US $35 by 2015.[130]

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[128] Energy Information Administration (EIA), "Annual Energy Outlook 2007 (Early Release)," EIA website, http://www.eia.doe.gov/oiaf/aeo/growth.html, accessed January 2007
[129] Ibid.
[130] World Bank, "Commodity Forecast (Nominal Prices)," World Bank website, http://web.worldbank.org/WBSITE/EXTERNAL/EXTDEC/EXTDECPROSPECTS/EXTGBLPROSPECTSAPRIL/0,,contentMDK:20423496~menuPK:902607~pagePK:2470434~piPK:2470429~theSitePK:659149,00.html, accessed February 2007

It is reasonable to expect that the price of crude oil derivatives, such as diesel fuel, would roughly track the price of crude oil. Hence, it is reasonable to predict that the supply and price of diesel fuel to the Stuart Island area will be more or less stable over the next ten years or more. Currently, the price for diesel fuel delivered to the Stuart Island area is between 80 and 90 cents per litre, depending on the volume used by each customer.

Based on confidential information received from resort operators, estimates of total diesel power generated in the Stuart Island area can be made. Information on diesel fuels costs from seven resorts, representing about 90% of the area's total power usage, was obtained in the investigation. An estimate of power consumed by the remaining smaller resorts was made by comparison with similar sized operations. This estimate was compared to total fuel delivery approximations that were obtained from the company that delivers diesel fuel to the Stuart Island area. In this way, an estimate of the total amount of diesel fuel used in the Stuart Island area in 2006 can be calculated by two different methods.

1 Calculation based on cost of diesel fuel
$ 1,250,000 at about 85 cents per litre = 1,470,588 litres

2 Calculation based on deliveries

Summer season	140,000 litres X 5 months =	700,000 litres
Winter season	105,000 litres X 7 months =	735,000 litres
Total		1,435,000 litres

Total fuel used in 2006, averaged and rounded **1,450,000 litres**

Correlation between these two totals is good and suggests a variation of only 3%. But since some of the raw data was based on recollections or estimates, it is reasonable to assume an accuracy of +/- 10%.

Power Produced by Diesel Generators

A wide range of gensets are used in the Stuart Island area, each with its own ratio of fuel consumption to power. Some are old, some new. Some are big, some are small. Some are fuel

efficient and properly tuned to maximize power output, other less so. Fuel consumption varies with the load on the genset. For the purposes of this estimate, a 50% load factor was used.

Some examples of genset specs follow:

- Cummins 45 KW 3.21 KWh / litre
- Caterpillar 36 KW 3.10 KWh / litre
- SDMO John Deere 55 KW 2.61 KWh / litre
- Cummins 113 KW 2.82 KWh / litre
- Cat 114 KW 2.46 KWh / litre
- SDMO John Deere 91KW 3.50 KWh / litre
- Cummins 250 KW 3.67 KWh / litre
- SDMO Volvo 409 KW 3.76 KWh / litre

Because there is so much variation in the power production of the various gensets, and because of the inherent uncertainty with regard to the load factors and characteristics of the gensets in use, for this estimate a somewhat arbitrary figure of 3.2 KWh / litre will be used.

1,450,000 litres X 3.2 KWh / litre = **4,640,000 KWh** in 2006

Divided by 8760 hours / year = **529 KW average** power produced in the Stuart island area in 2006.

There are other costs that contribute to the total cost of diesel generation, such as the cost of financing and the cost of maintenance. Based on the confidential information obtained from resorts in the course of the investigation the following can be said:

Total generating capacity – just under 2 MW
Effective generating capacity (because some generators are backups) – 1.3 MW
Generator life expectancy - 20 years with one rebuild
Annual maintenance per resort – between $2,000 and $10,000
Cost of a new 100 KW genset - $30,000 everything included

Appendix I

Estimate for all diesel generation in the Stuart Island area

- value existing gensets at 2/3 the replacement cost $ 400,000
- amortized at 5% per year $ 20,000
- maintenance $ 50,000
- financing at 7.5% $ 30,000

$ 100,000

The cost of the electricity currently being produced by the diesel generators at Stuart Island is

Fuel	$ 1,250,000 /	= 26.94 cents per KWh.
Generation costs	$ 100,000	
	$ 1,350,000	

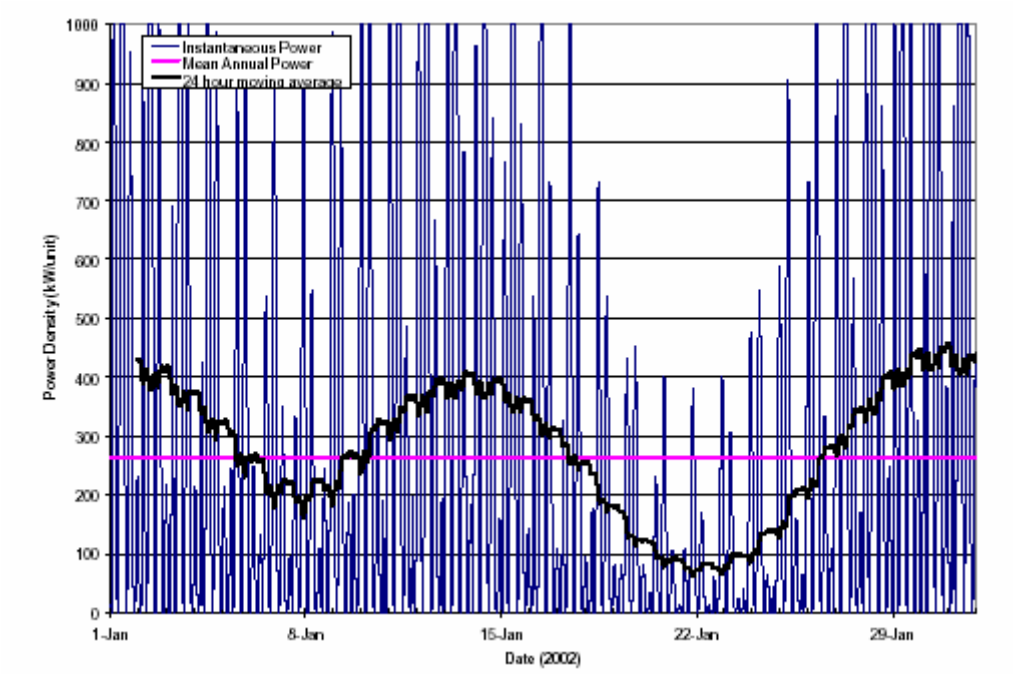
Divided by 4,640,000 KWh

= **29.1 cents per KWh**

Appendix I

Financial Analysis - Tidal power cost calculations

As noted in Triton Consultants reports and in EPRI reports, the average power produced by a tidal power generator on an annual basis is far lower than the rated capacity. According to Betz law, a theoretical maximum of 59% of the kinetic energy in a flow can be converted to mechanical energy using a turbine. Once ecological considerations, power conversion efficiencies and other factors are taken into consideration, only a fraction of the available tidal stream energy resource can be extracted at any site.[131] "In the case of tidal current energy extraction, the resource potential goes to zero two to four times per day and reaches its peak annual value only a few hours per year. For this reason, it is much more informative to speak of mean power in the context of tidal power, as such a definition integrates the effect of the highly variable daily and annual variation of the resource." [132] Triton calculated this factor to be about 26%, and EPRI's Knik Arm study calculated 29%. The following graph from Triton's 2002 Green Energy report clearly illustrates the extreme variability of the output of a tidal power generator.



[133]

So to generate an average of about 569 KW (per the diesel calculation) two 1 MW tidal stream generators would be required.

[131] Cornett, *Inventory of Canada's Marine Renewable Energy Resources,* p. 46
[132] Triton Consultants Green Energy Study for British Columbia.
[133] Ibid.

Based on confidential information received from equipment developers, compared with EPRI feasibility studies, a very rough estimate of the cost of a tidal power installation can be made. Information obtained in the investigation is summarized below (all figures in US Dollars). This cost comparison includes only available information on the cost of the turbine, support structure and installation and does not include costs specific to a remote, off-grid location.

Company or site	Size	Equipment	Installation	Total	$ per KW
EPRI Knik Arm[134]	760 KW	1,720,670	1,442,000	3,162,670	4161
EPRI Minas Passage[135]	1.1 MW	2,178,000	1,442,000	3,620,000	3258
Company A	1 MW	3,733,000	860,000	4,593,000	4,593
Company B					3,000 *
Company C	500 KW	1,425,000	1,440,000	2,865,000	5,730

* Estimate for a commercial size system

It can be seen that there is a considerable difference in the equipment and installation costs for the feasibility studies or project estimates shown above. None of the locations are as remote as the Stuart Island area and none are in channels where the tidal currents are as strong as at Stuart Island. There are many other costs involved in a tidal power turbine installation at Stuart Island; some can be reasonably estimated – and some cannot. In several cases it is simply not possible to estimate cost without further detailed engineering or hydrographic studies.

Following are additional costs associated with a tidal power facility at Stuart Island, further discussion can be found in the Financial Analysis - Uncertainty section of this paper:

- Approvals and permits are expected to be in the range of $400,000 to $500,000 comparable to the Canoe Pass site,[136] although this cannot be considered to be a certain figure.
- Financing costs are predictable at 7 - 8% per year.
- Annual maintenance costs are estimated to be approximately 4% of the installed cost for a commercial size system. [137]

[134] EPRI, "TP-006-AK Alaska Tidal Power System Level Design," EPRI website, http://www.epri.com/oceanenergy/attachments/streamenergy/reports/006-AK_06-10-06.pdf, accessed December 2006

[135] EPRI, "TP-006-NS Nova Scotia Tidal Power System Level Design," EPRI website, http://www.epri.com/oceanenergy/attachments/streamenergy/reports/006_NS_RB_06-10-06.pdf, accessed December 2006

[136] Canoe Pass Tidal Energy Consortium, *Canoe Pass Tidal Energy Demonstration Project - Detailed Project Description*

- Storage of excess electricity when power generated exceeds demand represents a significant cost with a great deal of uncertainty. At Stuart Island, when the tidal stream is flowing rapidly, power generators will be producing at full capacity, far in excess of peak demand. Energy storage is a critical factor for an off-grid application, so this is a major uncertainty which can affect project viability.
- Installation of turbines in the deep, fast flowing waters of the passages and rapids near Stuart Island may not be possible with currently available technology. Further detailed study of the seabed would need to be conducted before the anchoring technique could be determined, and equipment sourced to suit. Installation cost cannot be estimated for this study due to these uncertainties.
- Transportation to a site as remote as Stuart Island is likely to be a very large expense which is unknown. If a jack up barge is necessary for the installation, it would have to be brought in from the Gulf of Mexico or even from the North Sea.
- Subsea cables are generally installed in trenches dug into the seabed. In the channels of Stuart Island it is possible that the scouring action of the fast flowing tidal currents has prevented the buildup of sediments that would enable the digging of trenches. However, the EPRI Environmental study states that "Coarse-grained armored bottom sediments typically occur in channels having high current velocities that preclude the deposition of fine-grained sediments." [138] If that is the case, conventional cable trenching would be possible at Stuart Island. A study of the seabed would be required to estimate the cost of installation or anchoring of such a cable.
- On-shore interconnection costs are dependent on the system design, including the output of the turbine and the energy storage method, and can only be estimated as part of a complete system. On-shore distribution costs can be estimated at approximately $70,000 to $100,000 per kilometre for 25 kV power line in rough terrain,[139] with six to eight kilometres required for the west side of Stuart Island.
- Government participation in the project or grants may be available, but these must be applied for on an individual project basis and are considered on the specific merits of the project.

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[137] EPRI, "TP-006-AK Alaska Tidal Power System Level Design," EPRI website, http://www.epri.com/oceanenergy/attachments/streamenergy/reports/006-AK_06-10-06.pdf, accessed December 2006

[138] EPRI, "Instream Tidal Power in North America – Environmental and Permitting Issues," http://www.epri.com/oceanenergy/attachments/streamenergy/reports/007_Env_and_Reg_Issues_Report_060906.pdf p. 2-80, accessed February 2007

[139] Nick Hawley, BC Hydro, telephone interview by author, March 6, 2007

Financial Analysis - Uncertainty

At the present time, a great deal of uncertainty exists in the development and implementation of tidal stream power generation devices. Several technology developers have produced working prototypes, and some smaller scale devices up to 65 KW are in the water now and producing power. However, only one manufacturer has a proven, ocean tested device in the 300 KW range. MCT's Seaflow demonstration project has been in the water for three years and the technology has proven to be reliable. But Seaflow's surface piercing design is not suitable for the Stuart Island area with its frequent large marine traffic and narrow channels. OpenHydro's device currently under test at EMEC shows promise. Other developers' completely submerged devices could be suitable for the area, but the device development cost and time projections are uncertain.

Installation of a tidal turbine in the powerful currents near Stuart Island is another area where questions arise. The narrow, steep sided channels concentrate the power of the water and exactly how a turbine could be installed in these conditions is unknown. In addition, slack tide in the Cardero Channel is typically very short, creating additional installation challenges.

The State of Tidal Stream Power Generation Technology

As described in the Technology section, there are many developers of tidal stream power generation equipment. However, there has been only one demonstration project anywhere in the world that is actually using a device that approaches commercial size – MCT's Seaflow project off the English coast. MCT has a second generation project, Seagen, set to go into the water in 2007 which will have a capacity of 1.2 MW. Lunar Energy has plans to start testing a 1 MW device in the latter part of 2007. However, as none of these devices in the water yet, availability and performance characteristics are uncertain. One thing that is certain is that these are very large devices, with turbines or inlets between 15 and 20 metres in diameter.

All of the other device developers have been working with much smaller models, most in the range of 25 KW or less. Scaling up the device ten times or more cannot be expected to happen without challenges, and so this adds considerable uncertainty to the contemplation of a tidal power project.

Power Generation in Very Powerful Tidal Currents

According to Triton Consultants, "At some of these sites, such as Seymour Narrows, the current is too strong for a tidal current power installation using present techniques. However there is good reason to believe that advances in technology and construction techniques will make high current sites exploitable in the future."[140] The current velocities in the Stuart Island area are comparable to those at Seymour Narrows, although the magnitude of the resources is smaller. Maximum current flows at Stuart Island are up to 14 knots or almost 7 metres per second. Contrast this with mean maximum tidal current of 2.5 m/s at the Seaflow site.[141] Tidal power generation devices have not been proven in high current locations and this adds a tremendous amount of fundamental uncertainty.

Installation of Tidal Power Turbines in Very Powerful Currents

In its 2002 study, Triton Consultants has the following comment about installing tidal power devices in narrows with high current velocities: "Although these currents carry enormous quantities of energy, marine construction in such conditions would be extremely difficult and the cost and feasibility of constructing/maintaining infrastructure in these currents may be prohibitive."[142] As previously mentioned, only one tidal power turbine of significant size has been installed anywhere in the world. Much is unknown about installation of these devices in areas with moderate currents. Nothing at all is known about turbine installation in areas with high current velocities. Further, the availability or even the existence of the equipment that could do the installation is undefined and unknown.

Unknown Seabed Conditions in the Waters near Stuart Island

Little is known about the seabed in the passages and rapids of Cardero Channel near Stuart Island. A detailed study of the seabed composition and structure to determine the nature of the overburden and the rock beneath it would need to be conducted before turbine installation and subsea cable anchoring methods could be selected.

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[140] Triton Consultants, Green Energy Study for British Columbia.
[141] Fraenkel, Marine Current Turbines tidal turbine developments
[142] Triton Consultants, Green Energy Study for British Columbia.

Marine Traffic

There is frequent large marine traffic in the subject area – every week sees the transit of huge log booms through the area, some more than a thousand feet long. Towing a log boom through the narrow passages of Cardero Channel and the Yaculta Rapids requires precision timing, down to the minute.[143] An investigation would have to be conducted into the impact that an installation barge anchored in one of the passages would have on marine traffic. Innes Passage, closest to Sonora Island, has the advantage of little marine traffic, but the disadvantage of a shallow depth unsuitable for large turbines.

Debris

The amount of submerged debris of significant size, such as logs, that pass through the subject channels is unknown. A submerged log would cause catastrophic damage to a turbine and kelp suspended in the water column presents a risk of entanglement in the turbine. Further study into the amount and nature of the suspended debris is necessary. Steps that might need to be taken to protect tidal turbines are unknown.

[143] Martin Beaulieu, telephone interview with author, January 20, 2007

Feasibility

Determining the feasibility of a tidal power installation in the Stuart island area requires more than just looking at the financial bottom line. Consideration must also be given to the environmental and social aspects of such an important project. This is the Triple Bottom Line. After thorough investigation, and taking into account the aspects of the triple bottom line and other considerations, it has been determined that the installation of a tidal power generation plant at Stuart Island to replace the existing diesel gensets is not feasible at this time due to an excessive amount of uncertainty. A discussion of the elements of the triple bottom line plus aspects of the state of the technology follows.

Social

The importance of environment stewardship and sustainability has skyrocketed in Canadian public opinion over the last year. Much more attention is being paid to energy conservation and alternative energy. The time is right to advance new energy technologies, as the public is more and more willing to support the cost of development and demonstration. North America has lagged behind Europe in this regard, as several European countries have for several years offerred incentives to produce clean energy. For example, Germany's Renewable Energy Sources Act sets tariff rates for the supply of renewable energy to the power grid, on a sliding scale based on the energy source and the size of the operation. A small geothermal plant (up to 5 MW) can get 15 eurocents per kilowatt hour, and the basic rate for solar generated electricity is 45.7 eurocents per kilowatt hour.[144] This premium pricing provides an incentive for smaller renewable energy producers to bring these projects on line.

Governments in North America are finding that they must take action on environmental issues or risk defeat in the polls at the next election – a powerful incentive indeed. The Government of Canada has announced two new programs in 2007 – the ecoEnergy Renewable Initiative in January and the ecoTrust program in February 2007.[145] The Government of BC, in the Throne Speech on February 13, 2007 announced new measures to ensure that greenhouse gas

[144] The Green Power Group, "Government Incentives for Renewable Energy in Europe," The Green Power Group website, http://www.thegreenpowergroup.org/pdf/renewable_policy_Germany.pdf, accessed February, 2007
[145] Government of Canada, "Prime Minister unveils new Canada ecoTrust," Office of the Prime Minster website, http://www.pm.gc.ca/eng/media.asp?id=1532, accessed February, 2007

emissions are reduced and that ninety percent of electricity will be from clean, renewable resources.[146]

Often people will support an idea as long as it doesn't affect them directly - the "not in my backyard" (NIMBY) syndrome. But that is not the case with the people who live and work in the Stuart Island area. Without exception, the people from the area interviewed for this study were favourable to the concept of tidal power generation, both in general and in their own local waters.

Environment

The environmental benefits of replacing diesel generators with clean, quiet tidal power are readily apparent. The diesel generators presently in use in the Stuart Island area pump about 3872 tonnes of carbon dioxide into the atmosphere annually - more than 700 cars.[147] Diesel exhaust contains other pollutants, including carbon monoxide, oxides of nitrogen, unburnt fuel and soot. Replacement of diesel power with ocean energy would be consistent with government objectives for clean power generation.

In addition to the air pollution, gensets contribute to noise pollution – ironic for a quiet wilderness like Stuart Island.

Transportation of one and a half million litres of diesel fuel to the area every year poses another risk to the environment – the risk of spills. A major spill could involve up to 80,000 litres of diesel fuel washing up on the rocks surrounding Cardero Channel.

Financial

The high cost of diesel power generation in the Stuart Island area means that there are good possibilities for an alternate source of electricity to be viable. Residents and resorts are paying a lot to provide heat and light for their homes and businesses. Resorts in particular are willing to look at whatever alternatives there may be, as there is considerable money involved. Business

[146] Government of British Columbia, "Throne Speech," Government of British Columbia website, http://www.gov.bc.ca/bvprd/bc/content.do?brwId=%402Uq1U%7C0YQtuW&navId=NAV_ID_province&crumb=B.C.+Home&crumburl=%2Fhome.do, accessed February, 2007

[147] Energy Star, "Useful Facts and Figures," Energy Star website, http://www.energystar.gov/index.cfm?c=energy_awareness.bus_energy_use, accessed February, 2007

sustainability includes financial strength, and tidal power could provide valuable growth opportunities for the area if ecotourism could extend the tourist season.

Unfortunately, there is too much uncertainty in the various elements of costing to make a reliable financial determination. The tidal power turbines are in a very early stage of development, making costing uncertain. Installation of a tidal power generator in powerful currents like those that occur in the narrow passages near Stuart Island is questionable, as it has not yet been done anywhere in the world. Exactly what equipment could do the job, and where in the world it might be located, is a source of uncertainty without even considering the cost. Extensive (and likely expensive) investigation into the seabed conditions and the amount of debris carried by the current are necessary before a serious attempt at costing could be made.

Technology

In this case, there is another aspect to be considered in determining feasibility besides the Triple Bottom Line. Tidal power technology is in its infancy, and several aspects are not far enough advanced to recommend a tidal power generation facility at Stuart Island. First, the turbines themselves have not developed yet into full scale, commercial ready units of the size that would be required to replace the diesel generators in the Stuart Island area. While recent events show promise, such as the OpenHydro installation at EMEC, MCT's Seagen project set to go in the water at Strangford Narrows this spring and Lunar Energy's full size unit targeted to go in the water at EMEC late this year, the technology has not yet advanced to the point where a device can be recommended.

Deployment of the tidal stream power generation devices in very strong currents such as those found at Stuart Island has not yet been attempted, nor has the development of the anchoring techniques that may be required. It is likely that the ship or barge required for the installation would have to be tested in a narrow channel / powerful current environment before such techniques could be developed. Such a vessel may have to come all the way from the North Sea, which would be a large expense with no guarantee of success.

Storage of a large amount of energy in an off-grid situation is a very significant unknown. The situation at Stuart Island could result in excess power production at peak times of more than one megawatt. Engineering a system that could capture that much power and store it for a

relatively short time, then make it available to draw from would be challenging and very site specific. The entire system would have to be designed together, from the output of the tidal generator, to the cable length, to the voltage for transmission to shore, to the power conversion and finally to the storage device.

Appendix I

Marketability of tidal power solutions

One of the objectives of the Alternative Energy Task Force is to market BC solutions to the high-growth areas of the world to help create export opportunities.[148] There is a very real opportunity for Canadian and BC companies to develop and market tidal power solutions worldwide. As previously mentioned, the industry is in its infancy. Companies from the UK would have to be considered to be in the lead, but Canadian companies are not far behind and could make up ground quickly. Resource opportunities abound in Canada, notably Minas Basin on the east coast and several potential locations on the west coast such as Discovery Passage. Moreover, there are opportunities for projects in BC that would develop unique capabilities, like expertise in high velocity current deployments.

Off-grid tidal power generation, as this study has shown, comes with its own set of challenges. However, as the technology advances, some of these challenges could be turned into opportunities. Developing package systems including the turbine, power conditioning and storage may be an excellent opportunity. This kind of package could be developed to provide solutions to remote communities here in BC, and then sold to countries around the world. Production of fresh water is another way to add value to a package solution that would be especially useful in island applications where natural fresh water is scarce.

Services are an ever-increasing part of the global economy. Companies and individuals can develop expertise in construction, deployment and installation of tidal power systems and market these skills internationally. Some of the conditions on the BC coast that are the challenges of today could represent the valuable, exportable service of tomorrow. “Contrary to popular belief, large tidal currents do not necessarily require a large tidal range. Some of the largest tidal flows in the world occur between the islands on the east side of the Philippines where the tidal range is small but the tide is high in the Pacific at the same time that the tide is low within the Philippine Islands. In technical terms, this is described as the two tides being 180 degrees (or half a cycle) out of phase; the result is very large tidal currents. Another factor that

[148] BC Ministry of Energy, Mines and Petroleum Resources, “Alternative Energy and Power Technology: A Strategy for BC,” BC Ministry of Energy, Mines and Petroleum Resources website, http://www.gov.bc.ca/empr/down/alternative_energy_task_force_strategy_final_april_5_05.pdf, accessed January 2007

impacts the magnitude of tidal currents is the presence of narrow passages; these passages result in a narrowing and concentration of tidal flow."[149]

The very powerful tidal currents and narrow channels of BC waters could prove to be the laboratory for developing skills that could be used to harness the power of the tides in other challenging sites around the world. Thus there are opportunities for British Columbians to develop exportable skills that would be unique in the world market. Consulting expertise can be developed in the following areas:

- Environmental impact and permitting
- Installation
- Site selection
- Project management
- Project design, tying all aspects together.

[149] Tarbotton and Larson, *Canada Ocean Energy Atlas (Phase 1)*

Recommendations

Arising from this study are six recommendations for the BC Ministry of Energy, Mines and Petroleum Resources (MEMPR). These recommendations are intended as concrete steps that can be taken to further the growth and development of the tidal power industry in BC, and to help guide future policy and programs.

Continue to support the industry

MEMPR has been an active supporter of tidal power though its assistance in establishing the Ocean Renewable Energy Group and its active participation in events and symposia. This support has been very valuable to the industry and the companies within it. With new initiatives recently announced by both the federal and provincial governments, continued strong involvement by MEMPR is vital to the growth and prosperity of the industry in BC.

Get the general public involved

In Alberta, individuals can choose to get involved in alternative energy by paying a premium for wind power. The wind power goes on to the grid, of course, but by “buying” more expensive wind power, these consumers are helping to fund the development of alternative energy capacity voluntarily. BC Hydro already has green power certificates available for purchase by its corporate customers. MEMPR can work with BC Hydro to extend the program so that the general public can participate in it.

Resolve Uncertainties

This study has identified a great deal of uncertainty that exists in the development of tidal energy technology and installations. The MEMPR could take a leading role in identifying these uncertainties and taking steps towards their resolution. Because many of these uncertainties are quite specific to the BC coast, resolving them would tend to confer the benefits on companies working in BC waters. This would enhance the development of a technology cluster of tidal energy expertise in BC.

Appendix I

Advocate for streamlined approval process

Work with relevant agencies and departments to establish a permitting and approvals policy to streamline the procedures of obtaining the necessary permits and navigating the environmental review process. This would involve coordination with the appropriate federal department(s) and could involve sponsoring fish or marine mammal impact studies, or studies on the effect of reducing tidal flows.

Clean power for remote communities

Continue the work being done to bring clean electricity to remote communities, and work with BC Hydro on the Remote Community Electrification program. Act as a conduit between technology developers working in complementary areas. For example, fuel cells could be an answer to the energy storage situation for a small off-grid tidal power generation installation. MEMPR could act as an intermediary to bring those technology developers together.

Continue to encourage private sector investment

Private sector investment is critical to the success of the tidal energy industry in BC. The BC Government, through MEMPR, should create incentives to encourage entrepreneurial activity in the development of tidal power devices and installations. As noted earlier in the German example, rates paid to Independent Power Producers (IPPs) can be structured to encourage the development of targeted technologies. MEMPR can act as a resource for tidal power technology developers to make them aware of programs offered by other branches of the BC government, such as the tax credits available to investors in eligible projects through the Venture Capital Program under the auspices of the Ministry of Economic Development.

Appendix I

Conclusion

Tidal power holds great promise for providing clean power to remote, off-grid communities. But not right now.

At this point in time, tidal power technology is not far enough advanced for it to be feasible for installation at Stuart Island to replace the existing diesel generators. However, it won't be long until commercial size devices have been built and tested. There are a handful of Canadian manufacturers of tidal turbines that have working small scale devices that will soon be scaled up for use in commercial applications. The world leaders in the field are in the UK, but Canadian developers are not far behind.

Canada is rich in potential tidal resources. Minas Basin, on the east coast is a tremendous resource, both in terms of magnitude and proximity to the electricity market. The BC coast has 89 potential development sites, and perhaps more importantly, resources unlike any that are been developed in the world right now. So an opportunity exists for Canadian and BC device manufacturers and site developers to become world leaders in tidal power generation.

Even though a tidal power project for the Stuart Island is not feasible at this time, great potential exists for tidal power generation in BC.

The time for action is now. A focus on ocean energy can firmly establish the path to BC's future prosperity.

Appendix I

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Appendix I

Glossary

Alternative energy	Power produced by methods other than conventional
Clean energy	Power produced using non-polluting technologies
Conventional energy	Power produced by large hydro, nuclear or hydrocarbon fueled plants
Genset	Common name for a diesel generator assembly
Green energy	Power produced using non-polluting technologies
Grid	Power grid, as the North American electrical power grid
Knot	Nautical mile per hour 1 knot = 1.15 miles per hour = 0.51 m/s
KW	Kilowatt, one thousand Watts
KWh	Kilowatt hours, kilowatts produced or consumed in one hour
m/s	Metres per second 1 m/s = 1.94 knots
MW	Megawatt, one million Watts
NGO	Non Governmental Organization
Off-grid	An area or system that is not connected to the electrical power grid

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Appendix I

Tidal current energy assessment for Johnstone Strait, Vancouver Island

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Abstract: The maximum tidal power potential of Johnstone Strait, BC, Canada is evaluated using a two-dimensional finite element model (TIDE2D) with turbines simulated in certain regions by increasing the drag. Initially, side channels are closed off so that the flow is forced through one channel to test the validity of a general analytic theory [**1**] with numerical results. In this case, the modelled power potential of 886 MW agrees reasonably well with the analytic estimate of 826 MW. In reality, two main channels, Discovery Passage and Cordero Channel, connect the Pacific Ocean to the Strait of Georgia. Turbines are simulated in Johnstone Strait, northwest of the two main channels, and separately for Discovery Passage and Cordero Channel. Northwestern Johnstone Strait is similar to the one channel case as the flow must go through this channel, but Discovery Passage and Cordero Channel are different as the flow can be diverted away from the channel with the turbines and into the other channel. The maximum extractable power in northwestern Johnstone Strait is found to be 1335 MW, which agrees well with the theoretical estimate of 1320 MW. In Discovery Passage and Cordero Channel, the maximum extractable power is modelled to be 401 and 277 MW, respectively, due to the flow being partly diverted into the other channel. In all cases, the current is reduced to between 57 and 58 per cent of the undisturbed flow, close to the 56 per cent predicted by the analytic theory. All power calculations are for the M2 constituent alone, as this is the largest current in the region. The total power from the eight major constituents (M2, S2, N2, K2, K1, 01, P1, and Q1) can be obtained by multiplying the power estimates for M2 by 1.12.

Keywords: tidal power, alternative energy, renewable energy, energy assessment

1 INTRODUCTION

Traditionally, tidal energy is extracted by blocking the entrance of a small bay with a barrier containing numerous sluices and turbines. The sluices allow the water to enter the bay on the flood tide but are closed at high tide. The water is then released through turbines when there is a large enough head difference due to the ebbing tide outside the barrage. A tidal power plant of this nature is located in the Bay of Fundy at Annapolis Royal with an installed capacity of 18 MW. A more complex scheme can generate electricity on both the flood and the ebb tide though this operates with a smaller head. The world's largest two-way generation tidal power plant is at La Rance, France, with an installed capacity of 240 MW and an average production of about 100 MW [**2**].

Although tidal power barrages produce zero emissions while operating, there are still many other environmental concerns [**3**], mostly due to a prolonged high tide inside the basin and a decrease in the tidal current speed. These concerns are reduced slightly with two-way generation, which more closely mimics the real tide, but there are still ecological impacts which will vary widely from site to site depending on the local tidal regime [**2**]. There may also be impacts on the tidal regime on the seaward side of the barrage [**4**], which could have serious implications for the neighbouring coastline.

In response to some of the environmental and ecological concerns with tidal barrages, there has

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been a strong interest in harnessing power from tidal currents in a similar fashion to wind power generation [**5**]. This is seen as both a cheaper and more ecologically sound alternative to building a large tidal barrage. In 2002, Marine Current Turbines Ltd. (http://www.marineturbines.com) installed a single turbine with a rated capacity of 300 kW off Lynmouth, Devon, UK. This turbine only generates electricity for the tidal current moving one way, but there are proposals for a two-way rotor with a 1 MW rated capacity off the coast of Northern Ireland. Small tidal current projects are also underway at Race Rocks, BC, Canada (http://www.racerocks.com/racerock/energy/tidalenergy/tidalenergy.htm) and in the East River, New York City (http://www.verdantpower.com) with plans to install only one or two turbines. The majority of these projects are small scale (i.e. <1 MW) and will have little impact on the tidal currents at the site. However, for larger projects the turbines will tend to block the flow, thus reducing the power generated. Studies on how much energy can be extracted and the impacts on the tidal regime vary widely [**1**, **5**–**8**].

A common approach for evaluating tidal current potential is to assume that some percentage of the kinetic energy flux of the tidal flow (i.e. $(1/2)\rho u^3 \times$ the cross-sectional area) can be extracted for commercial use. An often quoted limit is the Betz limit [**9**], which claims that a maximum of 59 per cent of this kinetic power is available for extraction. However, this may be unrealistic because of the various assumptions made by Betz [**9**]. For example, Gorban *et. al.* [**10**] argued that only 35 per cent of the power may be extracted if one allows for the curvature of streamlines around the turbine. Regardless of what efficiency factor is used, the u^3 dependence (and a linear dependence on cross-sectional area) suggests that placing the turbines in the narrowest part of a confined stream will produce the most power. This may be true for an isolated turbine, or even a few turbines, as long as there is little change to the existing flow. However, it cannot apply to larger scale projects where there may be an appreciable change to the underlying flow because of the extra drag from the turbines. As more turbines are added, the flow is reduced, ultimately to the point at which the power produced decreases.

This article estimates the maximum power potential of the Johnstone Strait region (Fig. 1) in British Columbia, Canada. This region has very high tidal currents and has been proposed as an excellent site for harnessing tidal current energy [**5**]. First, theoretical calculations concerning the extraction of energy from the tidal currents are reviewed. The theory will then be applied to Johnstone Strait and compared with results from a numerical tidal model of the region.

2 A THEORETICAL APPROACH

For a single channel between two large basins, a general analytic theory to estimate the maximum extractable tidal power has been developed [**1**]. Turbines are simulated by increasing the friction across the entire cross-section of the channel. Assuming the wavelength of the tide is much longer than the channel length, so that the volume flux is constant along the entire channel, and the height difference between the ends of the channel does not vary with the addition of extra friction, the estimated maximum extractable power for a single tidal constituent was shown by Garrett and Cummins [**1**] to be given by

$$P_{\max} = \gamma \rho g a Q_{\max} \tag{1}$$

Here ρ is the density of seawater, g is the acceleration due to gravity, a is the amplitude of the sinusoidal height difference between the ends of the channel, and $Q_{\max}$ is the maximum volume flux in the natural tidal regime. All calculations assume the constant values for ρ and g of 1025 kg/m^3 and 9.81 m/s^2, respectively. The coefficient γ only varies over the small range between 0.20 and 0.24 and is determined by whether the forcing is balanced by acceleration or friction in the natural state without added drag from turbines.

The appropriate value of γ in a given situation may be determined by examining the phase lag of the current behind the maximum elevation difference in the natural state. If the forcing is balanced by acceleration, the phase lag is 90° and $\gamma = 0.24$, whereas if the forcing is balanced by friction and/or the effect of flow separation, and the response thus quasi-steady, the phase lag is zero and $\gamma = 0.21$. There is a small dip to a minimum $\gamma = 0.196$ for intermediate situations (see Fig. 4 of Garrett and Cummins [**1**]). For Johnstone Strait, the along-strait average phase lag is 35°, which is in between the two limits but closer to the quasi-steady case. A value of 0.20 is appropriate for γ and is used in this article.

Garrett and Cummins [**1**] showed how the quasi-steady limit can be examined analytically. In this case, the potential power P as a function of the peak flow rate, Q, with added turbines may be written

$$P/P_{\max} = \left(\frac{3^{3/2}}{2}\right)\left(\frac{Q}{Q_{\max}}\right)\left[1 - \left(\frac{Q}{Q_{\max}}\right)^2\right] \tag{2}$$

where $P_{\max}$ is the maximum power given by equation (1) and, as already defined, $Q_{\max}$ is the maximum volume flux in the natural tidal regime. The essential physics of the situation is

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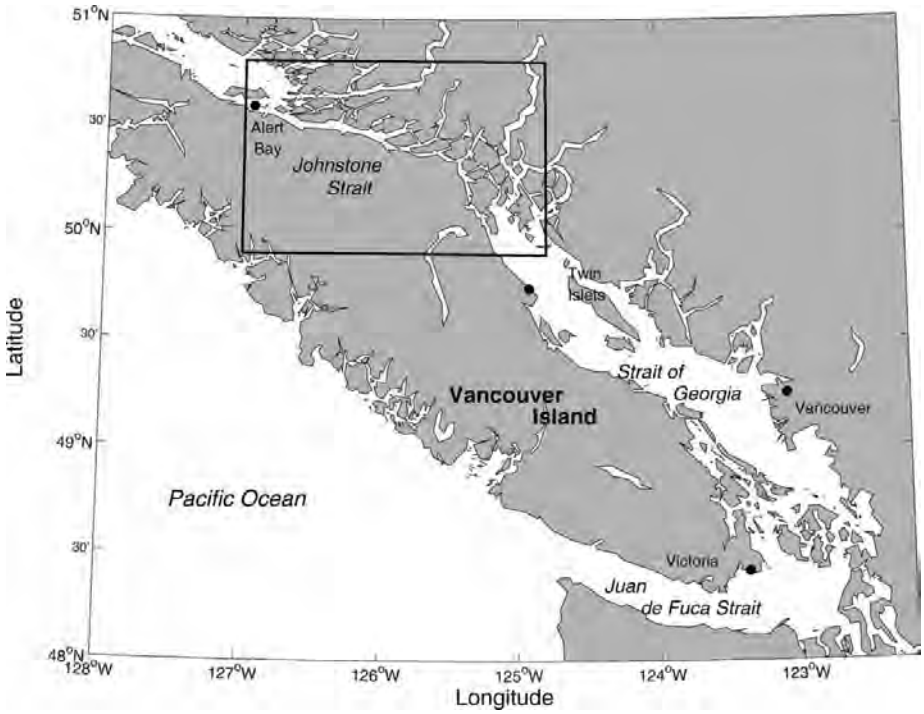

Fig. 1 Map of Vancouver Island. The location of the inset map (Fig. 3) is shown with the solid black line

well illustrated by equation (2). The term inside the square brackets is a non-dimensional form of the head loss across the fence of turbines, or an array of fences, and is zero when there are no turbines so that $Q = Q_{max}$. As the number of turbines increases, this head loss increases as Q decreases. The power is given by the head times the volume flux. Ultimately, when so many turbines have been added that the flow is completely blocked, all the head loss originally associated with the natural state is transferred to the turbine array but the power produced is zero as there is no flow! Figure 2 is a graph of equation (2) illustrating this increase and then decrease of P as Q decreases from Q_{max} to zero. At maximum power extraction, the volume flux drops to 58 per cent of that in the natural regime and 2/3 of the original head along the whole channel has been transferred to the turbine array. For a 10 per cent reduction in the current, which might be more acceptable for environmental reasons than the 42 per cent decrease at the maximum, the available power is still 44 per cent of equation (1) with $\gamma = 0.21$. A very minor point worth mentioning is that the current referred to here is the current averaged over some suitable time. For low energy extraction, the reduction in this average current may be less than the magnitude of turbulent current fluctuations.

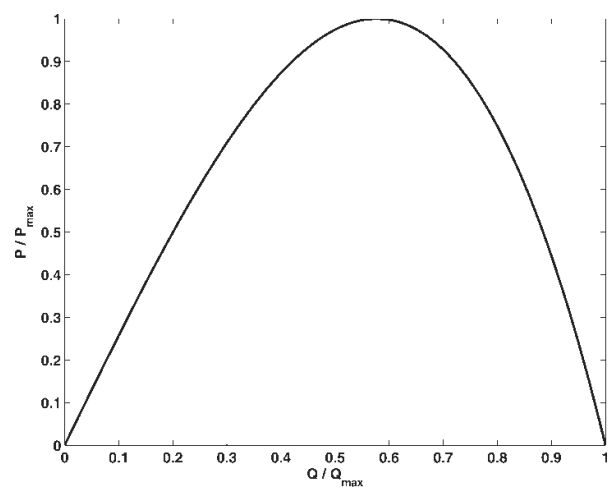

Fig. 2 The variation in the extractable power as a function of the reduced volume flux due to the presence of turbines for the situation in which there is a quasi-steady force balance in the natural state between pressure head and friction [**1**]. The volume flux is expressed as a fraction of the peak volume flux in the natural state and the power as a fraction of the maximum that can be extracted

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These simple results are for the situation in which the natural state has a balance between forcing and friction. Numerical results (P. Cummins, 2006, personal communication) show that in the other limit with the basic balance between forcing and acceleration, the current at maximum power is 70 per cent of that in the natural state. For our intermediate situation, this fraction is 56 per cent, close to the 58 per cent for the quasi-steady limit.

3 JOHNSTONE STRAIT REGION

Much of Johnstone Strait (Figs 1 and 3) has a typical width of 4 km and mid-channel depths up to 400 m, while Seymour Narrows and Cordero Channel have minimum widths of 0.8 and 0.5 km, respectively, and mid-channel depths as little as 50 m. These constrictions and the near 180° phase difference between tidal elevations in the northern Strait of Georgia and Queen Charlotte Strait create some of the largest tidal currents in the world. Current speeds in Seymour Narrows can reach 7.7 m/s [**11**], with the along-channel M2 current amplitude being 4.7 m/s [**12**]. Gillard Passage and Arran Rapids, at the southern end of Cordero Channel, have maximum current speeds of 5.7 and 6.7 m/s, respectively [**11**]. Although there are also substantial estuarine flows in the region because of the runoff of several rivers, of which the Fraser is the largest [**13**, **14**], these flow values will not be included in this study. Likewise, important baroclinic features associated with the tides [**13**] will be neglected by assuming a homogeneous density for all model simulations and power potential calculations.

4 A NUMERICAL APPROACH

Tidal heights and currents are calculated with the TIDE2D finite element model, which solves the two-dimensional shallow water equations with conventional hydrostatic and Boussinesq assumptions. Particulars of the numerical scheme are described in detail by Walters [**15**]. The model application uses the same triangular grid, encircling Vancouver Island, that was employed in Foreman *et al.* [**12**]. The model grid was created using the software package TRIGRID [**16**] and digital coastline and bathymetric data obtained from the Canadian Hydrographic Service and the National Oceanic and Atmospheric Administration. Grid element sizes were chosen to preserve important coastline and bathymetric features such as the numerous narrow channels in the Johnstone Strait region. Triangle sides range from 12 km in the ocean west of Vancouver Island to 130 m in Seymour Narrows. In order to ensure that volume transports within channels are accurate, the depths assigned to each node represent an average of nearby soundings.

Although many tidal constituents can be investigated, only M2 was employed here to speed up computation and to more easily relate the work to the theoretical results of Garrett and Cummins [**1**]. Moreover, the tidal currents for the region are predominantly semi-diurnal, so the M2 constituent will be the major contributor of extractable current energy.

For the natural tidal regime, a bottom friction coefficient of 0.007 was assumed everywhere except for eastern Juan de Fuca Strait and Discovery Passage, where the values were assumed to be 0.02 and 0.013, respectively. All coefficients are larger than normal to compensate for the inability of the model to represent correctly all the dissipation mechanisms, such as unresolved flow separation, with a conventional coefficient of 0.003 [**12**], and to allow for M2 being the only modelled constituent when in reality, the other constituents make significant contributions to the non-linear bottom friction. The values of the friction coefficients were chosen to obtain a good agreement between the modelled and observed tidal elevations since, for tidal power calculations, an important aspect of the tidal height field is the sinusoidal height difference, between the ends of the channel, which is forcing the current. The height difference is calculated between Alert Bay and Twin Islets (Fig. 1) where the observed M2 elevations are obtained from a harmonic analysis [**17**] of the recorded time series [**11**] at each location. The modelled value of 2.11 m is nearly identical to the observed value of 2.12 m.

4.1 Energy dissipation rate

One way to compute the dissipation is to take the difference between the energy flux into and out of a section of the channel. However, this can lead to a large relative error when the difference is small compared to the incoming and outgoing energy fluxes. Also, it has been shown [**18**] that, since TIDE2D employs a wave-equation formulation, volume is not always conserved locally. This leads to a continuity equation residual that contributes to the energy budget and remains a matter of concern with the finite element approach. Nonetheless, the success of the model in reproducing the natural tidal regime accurately in a number of regions [**19**, **20**] suggests that it is still reliable for estimates of the current and hence for direct calculations of the energy dissipation rate.

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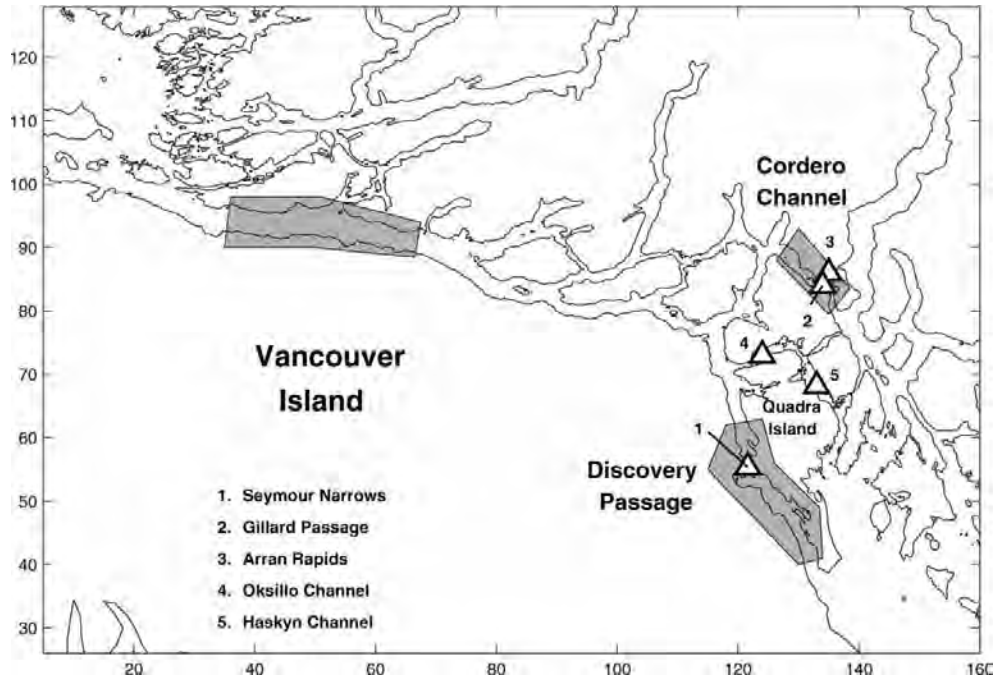

Fig. 3 Transect locations for the addition of synthetic turbines in Johnstone Strait. The shaded areas are the locations where turbines were simulated. The axes give the horizontal distances in kilometres

The rate at which energy is dissipated for a section of the seabed is calculated by integrating the bottom friction, that is,

$$P = \int\int_A \rho C_d \overline{|u^3|}\ \mathrm{d}A \tag{3}$$

where C_d is the quadratic bottom friction coefficient, u is the tidal current speed, and dA is an element of the area of the seabed.

5 TURBINE SIMULATIONS

The additional dissipation associated with the presence of turbines is simulated by increasing the bottom friction coefficient over a region of model nodes to represent a 'farm' of turbines. The bottom friction coefficient is increased to $C_d = k_0 + k_t$ where k_0 is the natural bottom friction coefficient and k_t is that associated with the added turbines. The energy dissipated solely by the turbines is

$$P_t = \frac{k_t}{k_0 + k_t} P \tag{4}$$

Figure 3 shows the areas of the simulated turbine farms. Using a two-dimensional numerical model it can be shown that these turbines extract energy from the entire cross-section of the tidal current flowing through a particular channel. This is similar to proposals for one or more tidal fences across the whole channel.

5.1 One Channel Open

To mimic the single channel case of Garrett and Cummins [**1**], we first close off the Cordero Channel and the Oksillo and Haskyn Channels on the eastern side of Quadra Island (Fig. 3) by disconnecting the nodes there. Although the system is still not exactly a single channel, because of some flow splitting in the central part of the strait, all the water entering into the Strait of Georgia must now pass through Discovery Passage and thus cannot be diverted away from the channel with the turbines. In this case, the height difference between Twin Islets and Alert Bay is 2.27 m.

Figure 4 shows the maximum M2 tidal volume flux for certain transects through Johnstone Strait before turbines are added. Along-channel variations in the volume flux are partly due to the limited accuracy of interpolating the volume flux to the transect location and partly due to the local accumulation or loss of water as the sea level changes with time.

The bottom friction coefficient is steadily increased in Discovery Passage until the extracted

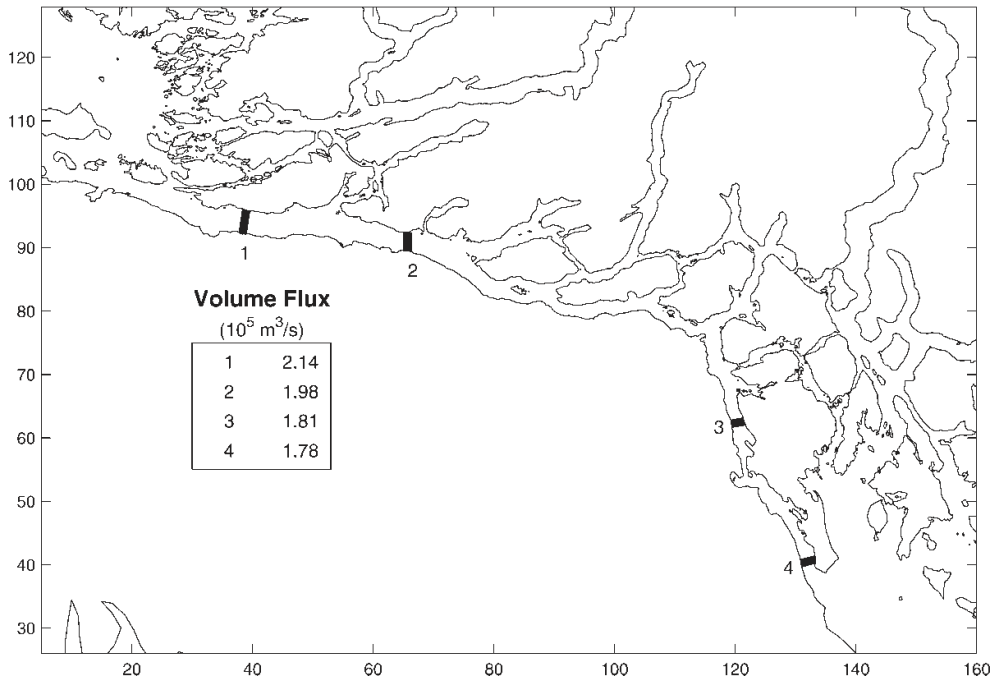

Fig. 4 Maximum volume flux with Cordero Channel effectively blocked and no turbines in Discovery Passage or Johnstone Strait. The axes give the horizontal distances in kilometres

energy, calculated using equation (4), peaks, as shown in Fig. 5. At peak power, the extracted energy is 886 MW with a corresponding drop in the maximum volume flux to 58 per cent of Q_{max}, close to the theoretical expectation of 56 per cent cited earlier. The modelled power of 886 MW agrees reasonably well with the analytic value of 826 MW from equation (1) using 1.81×10^5 m^3/s for the maximum volume flux, 2.27 m for a, and $\gamma = 0.20$. At peak power, a increases to 2.35 m, which is only a 3.5 per cent increase from the natural regime. This increase in the head would add, at the most, 3.5 per cent to the peak power obtained from equation (1), bringing 826 MW up to 855 MW, closer to the value from the numerical model.

5.2 All channels open

For the true tidal regime, we consider three separate scenarios. In the first, turbines are simulated in the northwestern region of Johnstone Strait, leaving open the two main channels, Discovery Passage and Cordero Channel, that connect to the Strait of Georgia. This region of Johnstone Strait is located in series with the major branching of the flow into Discovery Passage and Cordero Channel and thus should give results similar to those for the one channel case. In the second scenario, we leave northwestern Johnstone Strait and Cordero Channel unmodified and simulate the presence of turbines in Discovery Passage, which has some of the largest tidal currents in the world [**14**] and is, therefore, a prime candidate for any future tidal current projects [**15**]. However, this channel not only has heavy

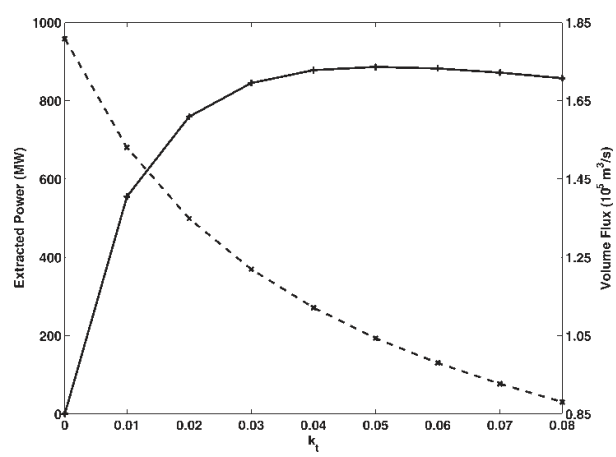

Fig. 5 Power dissipated by the addition of turbines in Discovery Passage, with Cordero Channel closed, as a function of increased friction coefficient. The solid line denotes the power dissipated (scale on left) and the dotted line denotes the change in volume flux through the channel (scale on right)

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shipping traffic, but is also a major migration corridor for salmon returning to the Fraser River. Therefore, it would seem unrealistic to be able to extract the maximum possible tidal energy as part of the channel would need to be kept open. Hence, in a third scenario, we simulate turbines in Cordero Channel, which has relatively high currents in addition to being out of the way of major shipping traffic, while leaving northwestern Johnstone Strait and Discovery Passage unmodified. As shown in Fig. 6, Cordero Channel and Discovery Passage (i.e. transects 9 and 10, respectively) have comparable volume fluxes in the natural state, thus rendering previous single-channel theoretical assumptions invalid in our second and third scenarios.

For turbines simulated in northwestern Johnstone Strait (Fig. 3), our first scenario, the modelled peak power is 1335 MW (Fig. 7). This is in good agreement with equation (1), which predicts a maximum extractable power of 1320 MW using 3.11×10^5 m^3/s for Q_{max}, 2.11 m for a, and $\gamma = 0.20$. In this section of Johnstone Strait, the volume flux varies between 3.00×10^5 and 3.21×10^5 m^3/s so 3.11×10^5 m^3/s is chosen as the mean maximum flux. The peak volume flux falls to 58 per cent of the value in the natural regime at maximum power extraction, again close to the expected 56 per cent. At maximum power, the height difference, a, increased to 2.18 m, which would increase the theoretical peak power, at the most, to 1363 MW.

Next, the bottom friction coefficient is slowly increased in Discovery Passage with Cordero Channel left unchanged, and the extracted power is shown in Fig. 8. The peak extractable power here is 401 MW. The same is then done for Cordero Channel with Discovery passage left unchanged, and the maximum extractable power is 277 MW as shown in Fig. 9. The peak volume flux drops to 57 and 58 per cent of the value in the natural state for Discovery Passage and Cordero Channel, respectively.

Using 2.11 m for a in equation (1), along with $\gamma = 0.20$ and 1.35×10^5 and 1.41×10^5 m^3/s for the peak volume fluxes in Discovery Passage and Cordero Channel, gives an estimated power potential of 573 and 598 MW, respectively. The single channel analytical model is inappropriate for these situations involving turbines in either Discovery Passage or Cordero Channel, however, due to the flow diverting into the channel without the turbines. This necessitates the need for a numerical model to accurately estimate the power potential, though it is possible that the single channel analytical model could be extended. In both of the cases evaluated above, at maximum power extraction the volume flux increases by 14 per cent in the channel without the

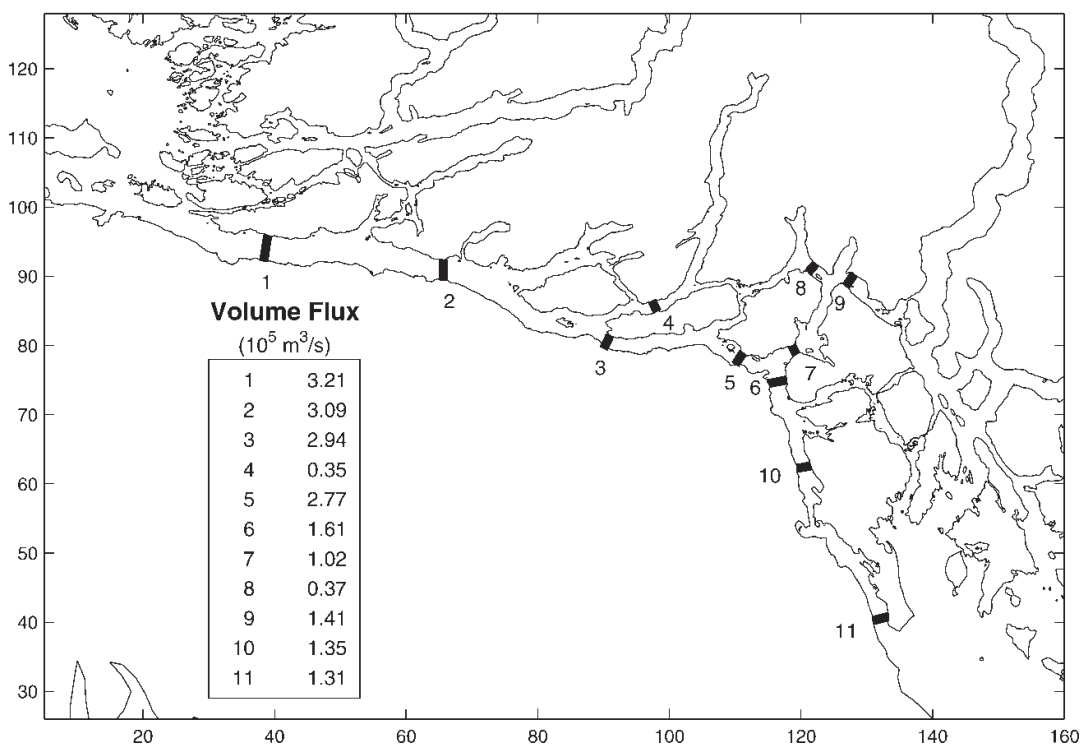

Fig. 6 Volume flux through Johnstone Strait with no channels blocked. The axes give the horizontal distances in kilometres

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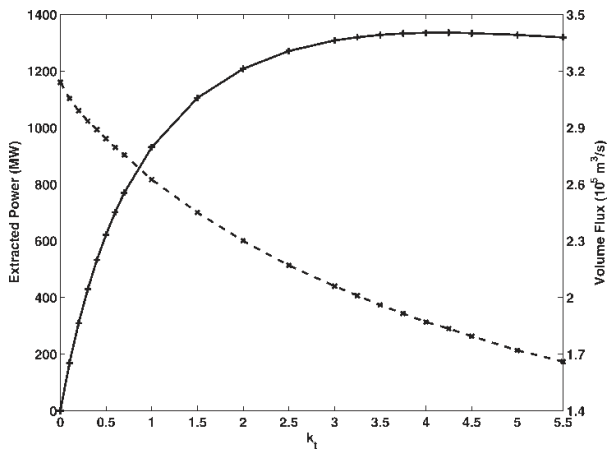

Fig. 7 Power extracted by the turbines in northwestern Johnstone Strait as a function of the extra friction coefficient. The solid line denotes the energy dissipation rate associated with the turbines (scale on left) and the dotted line denotes the change in peak volume flux through the channel (scale on right)

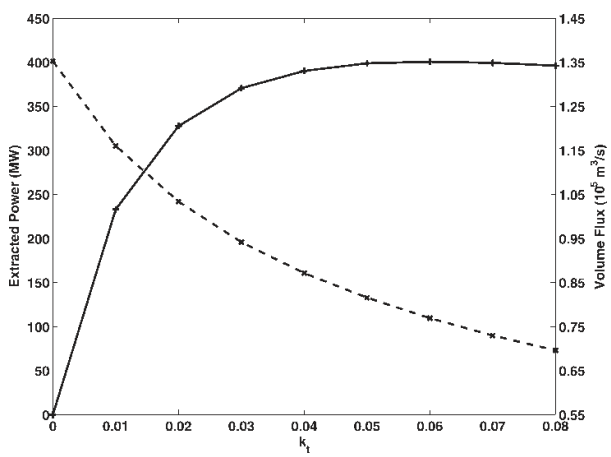

Fig. 8 Power extracted by the turbines in Discovery Passage as a function of the extra friction coefficient. The solid line denotes the energy dissipation rate associated with the turbines (scale on left) and the dotted line denotes the change in peak volume flux through the channel (scale on right)

turbines and the change in the height difference, a, is negligible.

5.3 Summary of results

The results of the turbine simulations along with the theoretical estimates for the maximum energy dissipation from equation (1) are shown in Table 1. For

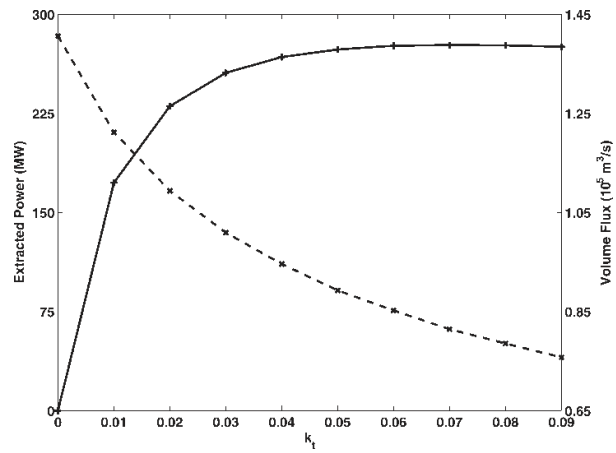

Fig. 9 Power extracted by the turbines in Cordero Channel as a function of the extra friction coefficient. The solid line denotes the energy dissipation rate associated with the turbines (scale on left) and the dotted line denotes the change in peak volume flux through the channel (scale on right)

Table 1 Results from simulating turbines in certain regions of Johnstone Strait

Location	Theoretical dissipation (MW)	Modelled dissipation (MW)	Percent vol. flux at max dissipation
Discovery Passage w/ Cordero closed	826	886	58
Johnstone Strait	1320	1335	58
Discovery Passage	573*	401	57
Cordero Channel	598*	277	58

Asterisks denote power estimates for channels where the water can be diverted and equation (1) is no longer valid.

the two cases with all the tidal flow going through the turbines there is good agreement between power estimates from equation (1) and numerical simulations. However, for the two cases where the flow can be diverted to a channel without turbines the theory is no longer valid and estimates cannot be made using equation (1). It is unclear why Cordero Channel, which has the greater volume flux in the natural regime, has a smaller power potential than Discovery Passage, even though both have roughly the same drop in volume flux, and the same increase in volume flux for the neighbouring channel, at peak power. Further study is required to discover the nature of this discrepancy.

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5.4 Adding other constituents

These results for M2 can be extrapolated to account for the entire tide [**1**]. For a multi-frequency tide, e.g. $\zeta_0 = a\cos\omega t + a_1\cos\omega_1 t + a_2\cos\omega_2 t\cdots$, the extractable power is multiplied in the quasi-steady limit by $1 + \frac{9}{16}(r_1^2 + r_2^2\cdots)$, where $r_1 = a_1/a$, $r_2 = a_2/a$, ... and a is the M2 sinusoidal height difference between Alert Bay and Twin Islets. The factor 9/16 is replaced by 1 if the basic state is dominated by acceleration rather than friction [**1**], but we retain it, as the basic state here is closer to the quasi-steady, frictionally dominated limit. The scaling factor was computed using the harmonic constants for the eight major tidal constituents: M2, S2, N2, K2, K1, O1, P1, and Q1 were calculated through a harmonic analysis [**17**] of the observed time series [**11**] at these two locations. Accounting for these eight major constituents instead of just M2 will only increase the total power potential by a factor of 1.12.

6 FAR FIELD EFFECTS

To determine the far field effects, the tidal height amplitudes were compared between the natural regime and the regime at maximum power extraction for the three cases with the real geometry (i.e. excluding the first case where the side channels are blocked). The one channel case is not analysed here as it seems unlikely that Cordero Channel, Oksillo Channel, and Haskyn Channel would all be blocked off to force the flow through Discovery Passage.

We are assuming here that the prescribed tidal elevation at the open boundary, which generally lies beyond the edge of the continental shelf, is unchanged. This is likely to be a good assumption because any significant changes in deep water would lead to large transport changes which would be incompatible with the rest of the ocean. Further discussion of this issue is given by Garrett and Greenberg [**21**].

The variation in the phase lag of the tidal elevation is negligible outside Johnstone Strait. The maximum change is an increase in the phase lag of 10° in the area where the turbines are added. The currents also vary little outside Johnstone Strait with the maximum deviation being a decrease of 2 cm/s in Juan de Fuca Strait. In the Strait of Georgia, the currents slightly increase between 0 and 1 cm/s.

Extracting 1335 MW from Johnstone Strait has an appreciable impact on the far field tidal elevations. In the Strait of Georgia, there is a near uniform decrease in the M2 amplitude of 15 cm. In Juan de Fuca Strait, the M2 amplitude increases in the western end and decreases eastward. A lot of this change is due to the degenerate M2 amphidrome near Victoria [**22**] moving towards the Strait of Georgia.

Similar patterns arise when extracting 401 and 277 MW from Discovery Passage and Cordero Channel, respectively, but the magnitude of the changes is smaller. In fact, the magnitude appears to vary linearly with the amount of energy extracted, i.e. the far field effects, away from Johnstone Strait have the same shape as for extracting 1335 MW out of Johnstone Strait, but the tidal height amplitude variation is scaled down by 30 per cent (401/1335) and 20 per cent (277/1335) for turbines in Discovery Passage and Cordero Channel, respectively.

The effects of blocking Johnstone Strait completely are very similar to extracting 1335 MW out of Johnstone Strait with a slightly greater decrease in the M2 amplitude in the Strait of Georgia and Juan de Fuca Strait. At peak extraction, which has maximized the balance between the dissipative force and the flow through the turbines, the far field effects are similar to blocking off the channel completely so no water flows through.

Estimates of the far field effects using only M2 will be inaccurate if Johnstone Strait has an appreciable effect on the other constituents. The diurnal tidal amplitude is comparable to the semi-diurnal tide in most of the Strait of Georgia (the K1 amplitude is in fact larger than the M2 amplitude at Victoria). There may be significant changes in the diurnal tides as the resonant period is closer to the diurnal band than the semi-diurnal band [**23**]. As a result, estimating far field effects using only M2 is insufficient. Further work on this may be desirable.

7 DISCUSSION

We have shown that, when the flow cannot be diverted away from the channel with the turbines, the numerical results for the tidal power potential agree well with the analytic theory of Garrett and Cummins [**1**]. For these two scenarios, the estimates using equation (1) are both within 10 per cent of the numerical results. Small variations in the volume flux along the channel and the slight increase in the head with added friction will cause small discrepancies in the calculated power potential, but variations in the volume flux and head difference appear to be either negligible or cancel each other out. Thus the assumptions made by Garrett and Cummins [**1**] appear reasonable and their model useful.

If the flow can be diverted away from the turbines, the analytic theory [**1**] is no longer directly

applicable. This is apparent for turbines added in Discovery Passage and Cordero Channel where the power potential is not predicted by equation (1) as it does not account for this diversion of the flow. These more complex channels can be addressed using a numerical model to estimate the maximum extractable power, though a semi-analytic extension of the basic theory could be undertaken. With flow diversion, equation (1) still gives an upper bound on the power potential, though this may not be very useful.

Given the support for the basic theory of Garrett and Cummins [**1**], it is clear that results rely on the model providing a good representation of the volume flux as well as the tidal elevation in the natural regime. Measurements of the M2 barotropic volume flux are available from current meter measurements in Johnstone Strait [**13**]. The peak volume flux was measured to be $2.6 \times 10^5\ \mathrm{m^3/s}$ from five current meters along a transect at roughly the same location as transect 2 in Fig. 6. This, along with 2.12 m for a and 0.20 for γ, would result in equation (1) estimating the maximum power potential to be 1108 MW for the entire channel. This is less than from the model which has a larger volume flux of roughly $3.1 \times 10^5\ \mathrm{m^3/s}$. Both observations and the model have uncertainties, so further work is needed to establish the correct volume flux. In particular, a more intensive current measurement program, using Acoustic Doppler Current Profilers instead of single current meters, could provide more accurate data on the tidal volume flux in the natural state. We emphasize that this would remove the sensitivity to the uncertainty of friction coefficients in the numerical model; as long as these are chosen so that the computed flux matches the observed value, they need not be accurate in every location.

In a study for BC HYDRO [**5**], the tidal current power potential was assessed for multiple sites along the BC coast, with the majority of these located in Johnstone Strait. The power potential at each site was estimated from the kinetic energy flux $(1/2)\rho u^3$ multiplied by the cross-sectional area. Only sites with current speeds greater than 2.4 m/s were chosen, excluding Seymour Narrows as the currents were deemed too high for present technology, and their estimated total power potential from 12 sites in Johnstone Strait was found to be 767 MW. This assessment looked at each site separately and assumed that extraction from one site will not affect extraction at another site, though this has been shown by Garrett and Cummins [**1**] and this study to be false. Also, in using the kinetic energy flux of the undisturbed flow as a metric for the maximum potential, changes to the flow due to the increased drag from energy extraction are neglected, quite apart from the fact that the kinetic energy flux varies from cross-section to cross-section.

Large current speeds are desirable for efficient turbine operation, and, for an isolated turbine, the extractable power is proportional to the kinetic energy flux of the basic flow through the area presented by the turbine. However, when turbines are present in the entire cross-section of a channel as a tidal fence, the maximum extractable energy is not proportional to the natural kinetic energy flux in any general way. The general analytic theory of Garrett and Cummins [**1**] has been shown here to be accurate in both predicting the change in the current from power extraction and determining the maximum power potential for a single channel where the water cannot be diverted away from the turbines. Specifically, the assumptions made in the analytical theory seem to be adequately valid when compared with the results from a numerical model.

Both the analytical model and the numerical model used here do use particular representations of the turbines. Future work will include investigating different ways to add friction to simulate turbines. One method would be to scale the turbine friction coefficient linearly with water depth so the body force will be constant for the whole turbine farm, i.e. $k_t = \alpha H$ where α is a constant and H is the water depth. This method has been applied to northwestern Johnstone Strait with nearly identical results to those obtained with the uniform friction coefficient increase.

Another important extension will be to increase the friction for only part of the channel in order to leave a portion open for shipping. In that case, of course, water can flow around the turbines rather than through them. Such an extension could be carried out using a two-dimensional model if the partial tidal fence occupies the whole water column in the vertical but is limited laterally, but a three-dimensional model is required if the turbines are confined near the sea floor. Preliminary investigations show that, in either of these scenarios, a turbine farm which is extensive in the along-channel direction is ineffective as the water will tend to avoid it and flow through the unrestricted part of the cross-section. Turbine fences would then need to be well spaced in the along-channel direction, allowing turbulent mixing to cause a recovery of the flow profile between fences. In this case, however, a loss of head is associated with the merging of flows that have, and have not, passed through a particular fence, giving less power than if the tidal fences occupy the entire channel [**24**].

Finally, we stress that the maximum extractable power predicted by Garrett and Cummins [**1**] and computed in this article would have to be reduced to allow for losses to drag on turbine support

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structures and to allow for the internal efficiency of the turbines themselves.

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Executive Summary

This book describes 207 ways in which the size of "electrical resources"—devices that make, save, or store electricity—affects their economic value. It finds that properly considering the economic benefits of "distributed" (decentralized) electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation (especially of the grid), and service quality, and by avoiding societal costs.

The *actual* increase in value, of course, depends strongly on the case-by-case technology, site, and timing. These factors are so complex that the distribution of value increases across the universe of potential applications is unknown. However, in many if not most cases, the increase in value should change investment decisions. For example, it should normally far exceed the cost differences between, say, modern natural-gas-fired power plants and wind-farms. In many applications it could even make grid-interactive photovoltaics (solar cells) cost-effective today. It should therefore change how distributed resources are marketed and used, and it reveals policy and business opportunities to make these huge benefits explicit in the marketplace.

The electricity industry is in the midst of profound and comprehensive change, including a return to the local and neighborhood scale in which the industry's early history is rooted. Through the twentieth century, thermal (steam-raising) power stations evolved from local combined-heat-and-power plants serving neighborhoods to huge, remote, electricity-only generators serving whole regions. Elaborate technical and social systems commanded the flow of electrons from central stations to dispersed users and the reverse flow of money to pay for power stations, fuel, and grid. This architecture made sense in the early twentieth century when power stations were more expensive and less reliable than the grid, so they had to be combined via the grid to ensure reliable and economical supply. The grid also melded the diverse loads of many customers, shared the costly generating capacity, and made big and urban customers subsidize extension of electric service to rural customers.

By the start of the twenty-first century, however, virtually everyone in industrialized countries had electric service, and the basic assumptions underpinning the big-station logic had reversed. Central thermal power plants could no longer deliver competitively cheap and reliable electricity through the grid, because the plants had come to cost *less* than the grid and had become so reliable that nearly all power failures originated *in* the grid. Thus the grid linking central stations to remote customers had become the main driver of those customers' power costs and power-quality problems—which became more acute as digital equipment required extremely reliable electricity. The cheapest, most reliable power, therefore, was that which was produced at or near the customers.

Utilities' traditional focus on a few genuine economies of scale (the bigger, the less investment per kW) overlooked larger *dis*economies of scale in the power stations, the grid, the way both are run, and the architecture of the entire system. The narrow vision that bigger is better ended up raising the costs and financial risks that it was meant to reduce. The resulting disadvantages are rooted in an enormous difference of scale between most needs and most supplies. Three-fourths of U.S. residential and commercial customers use electricity at an average rate that does not exceed 1.5 and 12 kilowatts respectively, whereas a single conventional central power plant produces about a million kilowatts. Resources better matched to the kilowatt scale of most customers' needs, or to the tens-of-thousands-of-kilowatts scale of typical distribution substations, or to an intermediate "microgrid" scale, thus became able to offer important but little-known economic advantages over the giant plants.

The capital markets have gradually come to realize this. Central thermal power plants stopped getting more efficient in the 1960s, bigger in the '70s, cheaper in the '80s, and bought in the '90s. Smaller units offered greater economies from mass-production than big ones could gain through unit size. In the '90s, the cost differences between giant nuclear plants—the last gasp of '70s and '80s gigantism—and railcar-deliverable combined-cycle gas-fired plants, derived from mass-produced aircraft engines, created political stresses that drove the restructuring of the industry. At the same time, new kinds of "micropower" generators thousands or tens of thousands of times smaller—microturbines, solar cells, fuel cells, wind turbines—started to become serious competitors, often enabled by information and telecommunications technologies. The restructured industry exposed the previously sheltered power-plant builders to brutal market discipline. Competition from micropower, uncertain demand, and the inflexibility of big, slow-to-build plants created financial risk well beyond the capital markets' appetite. Then in 2001, longstanding concerns about the inherent vulnerability of giant plants and the far-flung grid were reinforced by the 9/11 terrorist attacks.

The disappointing cost, efficiency, financial risk, and reliability of large thermal stations (and their associated grid investments) were leading their orders to collapse even before the cost difference between nuclear and combined-cycle costs stimulated restructuring that began to delaminate utilities. That restructuring created new market entrants, unbundled prices, and increased opportunities for competition at all scales—and thus launched the revolution in which swarms of microgenerators began to displace the behemoths. Already, distributed resources and the markets that let them compete have shifted most new generating units in competitive market economies from the million-kilowatt scale of the 1980s to the hundredfold-smaller scale that prevailed in the 1940s. Even more radical decentralization, all the way to customers' kilowatt scale (prevalent in and before the 1920s), is rapidly emerging and may prove even more beneficial, especially if it comes to rely on widely distributed microelectronic intelligence. Distributed generators do not require restructured electricity markets, and do not imply any particular scale for electricity business enterprises, but they are starting to drive the evolution of both.

Some distributed technologies like solar cells and fuel cells are still made in low volume and can therefore cost more than competing sources. But such distributed sources' increased *value*—due to improvements in financial risk, engineering flexibility, security, environmental quality, and other important attributes—can often more than offset their apparent cost disadvantage. This book introduces engineering and financial practitioners, business managers and strategists, public policymakers, designers, and interested citizens to those new value opportunities. It also provides a basic introduction to key concepts from such disciplines as electrical engineering, power system planning, and financial economics. Its examples are mainly U.S.-based, but its scope is global.

A handful of pioneering utilities and industries confirmed in the 1990s that distributed benefits are commercially valuable—so valuable that since the mid-'90s, most of the best conceptual analyses and field data have become proprietary, and government efforts to publish methods and examples of distributed-benefit valuation have been largely disbanded. Most published analyses and models, too, cover only small subsets of the issues. This study therefore seeks to provide the first full and systematic, if preliminary, public synthesis of how making electrical resources the right size can minimize their costs and risks. Its main findings are:

- The most valuable distributed benefits typically flow from financial economics—the lower risk of smaller modules with shorter lead times, portability, and low or no fuel-price volatility. These benefits often raise value by most of an order of magnitude (factor of ten) for renewables, and by about 3–5-fold for nonrenewables.
- Electrical-engineering benefits—lower grid costs and losses, better fault management, reactive support, etc.—usually provide another ~2–3-fold value gain, but more if the distribution grid is congested or if premium power quality or reliability are required.
- Many miscellaneous benefits may together increase value by another ~2-fold—more where waste heat can be reused.
- Externalities, though hard to quantify, may be politically decisive, and some are monetized.
- Capturing distributed benefits requires astute business strategy and reformed public policy.

Emerging electricity market structures can now provide the incentives, the measurement and validation, and the disciplinary perspectives needed to give distributed benefits a market voice. Successful competitors will reflect those benefits in investment decisions and prices. Nearly a dozen other technological, conceptual, and institutional forces are also driving a rapid shift toward the "distributed utility," where power generation migrates from remote plants to customers' back yards, basements, rooftops, and driveways. This transformation promises a vibrantly competitive, resilient, and lucrative electricity sector, at less cost to customers and to the earth—thus fulfilling Thomas Edison's original decentralized vision, just a century late.

207 Benefits of Distributed Resources

1 Distributed resources' generally shorter construction period leaves less time for reality to diverge from expectations, thus reducing the probability and hence the financial risk of under- or overbuilding.

2 Distributed resources' smaller unit size also reduces the consequences of such divergence and hence reduces its financial risk.

3 The frequent correlation between distributed resources' shorter lead time and smaller unit size can create a multiplicative, not merely an additive, risk reduction.

4 Shorter lead time further reduces forecasting errors and associated financial risks by reducing errors' amplification with the passage of time.

5 Even if short-lead-time units have lower thermal efficiency, their lower capital and interest costs can often offset the excess carrying charges on idle centralized capacity whose better thermal efficiency is more than offset by high capital cost.

6 Smaller, faster modules can be built on a "pay-as-you-go" basis with less financial strain, reducing the builder's financial risk and hence cost of capital.

7 Centralized capacity additions overshoot demand (absent gross underforecasting or exactly predictable step-function increments of demand) because their inherent "lumpiness" leaves substantial increments of capacity idle until demand can "grow into it." In contrast, smaller units can more exactly match gradual changes in demand without building unnecessary slack capacity ("build-as-you-need"), so their capacity additions are employed incrementally and immediately.

8 Smaller, more modular capacity not only ties up less idle capital (#7), but also does so for a shorter time (because the demand can "grow into" the added capacity sooner), thus reducing the cost of capital per unit of revenue.

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9 If distributed resources are becoming cheaper with time, as most are, their small units and short lead times permit those cost reductions to be almost fully captured. This is the inverse of #8: revenue increases there, and cost reductions here, are captured incrementally and immediately by following the demand or cost curves nearly exactly.

10 Using short-lead-time plants reduces the risk of a "death spiral" of rising tariffs and stagnating demand.

11 Shorter lead time and smaller unit size both reduce the accumulation of interest during construction—an important benefit in both accounting and cashflow terms.

12 Where the multiplicative effect of faster-and-smaller units reduces financial risk (#3) and hence the cost of project capital, the correlated effects—of that cheaper capital, less of it (#11), and needing it over a shorter construction period (#11)—can be triply multiplicative. This can in turn improve the enterprise's financial performance, gaining it access to still cheaper capital. This is the opposite of the effect often observed with large-scale, long-lead-time projects, whose enhanced financial risks not only raise the cost of project capital but may cause general deterioration of the developer's financial indicators, raising its cost of capital and making it even less competitive.

13 For utilities that use such accrual accounting mechanisms as AFUDC (Allowance for Funds Used During Construction), shorter lead time's reduced absolute and fractional interest burden can improve the quality of earnings, hence investors' perceptions and willingness to invest.

14 Distributed resources' modularity increases the developer's financial freedom by tying up only enough working capital to complete one segment at a time.

15 Shorter lead time and smaller unit size both decrease construction's burden on the developer's cashflow, improving financial indicators and hence reducing the cost of capital.

16 Shorter-lead-time plants can also improve cashflow by starting to earn revenue sooner—through operational revenue-earning or regulatory rate-basing as soon as each module is built—rather than waiting for the entire total capacity to be completed.

17 The high velocity of capital (#16) may permit self-financing of subsequent units from early operating revenues.

18 Where external finance is required, early operation of an initial unit gives investors an early demonstration of the developer's capability, reducing the perceived risk of subsequent units and hence the cost of capital to build them.

19 Short lead time allows companies a longer "breathing spell" after the startup of each

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generating unit, so that they can better recover from the financial strain of construction.

20 Shorter lead time and smaller unit size may decrease the incentive, and the bargaining power, of some workers or unions whose critical skills may otherwise give them the leverage to demand extremely high wages or to stretch out construction still further on large, lumpy, long-lead-time projects that can yield no revenue until completed.

21 Smaller plants' lower local impacts may qualify them for regulatory exemptions or streamlined approvals processes, further reducing construction time and hence financing costs.

22 Where smaller plants' lower local impacts qualify them for regulatory exemptions or streamlined approvals processes, the risk of project failure and lost investment due to regulatory rejection or onerous condition decreases, so investors may demand a smaller risk premium.

23 Smaller plants have less obtrusive siting impacts, avoiding the risk of a vicious circle of public response that makes siting ever more difficult.

24 Small units with short lead times reduce the risk of buying a technology that is or becomes obsolete even before it's installed, or soon thereafter.

25 Smaller units with short development and production times and quick installation can better exploit rapid learning: many generations of product development can be compressed into the time it would take simply to build a single giant unit, let alone operate it and gain experience with it.

26 Lessons learned during that rapid evolution can be applied incrementally and immediately in current production, not filed away for the next huge plant a decade or two later.

27 Distributed resources move labor from field worksites, where productivity gains are sparse, to the factory, where they're huge.

28 Distributed resources' construction tends to be far simpler, not requiring an expensively scarce level of construction management talent.

29 Faster construction means less workforce turnover, less retraining, and more craft and management continuity than would be possible on a decade-long project.

30 Distributed resources exploit modern and agile manufacturing techniques, highly competitive innovation, standardized parts, and commonly available production equipment shared with many other industries. All of these tend to reduce costs and delays.

31 Shorter lead time reduces exposure to changes in regulatory rules during construction.

32 Technologies that can be built quickly before the rules change and are modular so they can

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"learn faster" and embody continuous improvement are less exposed to regulatory risks.

33 Distributed technologies that are inherently benign (renewables) are less likely to suffer from regulatory restrictions.

34 Distributed resources may be small enough per unit to be considered *de minimis* and avoid certain kinds of regulation.

35 Smaller, faster modules offer some risk-reducing degree of protection from interest-rate fluctuations, which could be considered a regulatory risk if attributed to the Federal Reserve or similar national monetary authorities.

36 The flexibility of distributed resources allows managers to adjust capital investments continuously and incrementally, more exactly tracking the unfolding future, with continuously available options for modification or exit to avoid trapped equity.

37 Small, short-lead-time resources incur less carrying-charge penalty if suspended to await better information, or even if abandoned.

38 Distributed resources typically offer greater flexibility in accelerating completion if this becomes a valuable outcome.

39 Distributed resources allow capacity expansion decisions to become more routine and hence lower in transaction costs and overheads.

40 Distributed generation allows more learning before deciding, and makes learning a continuous process as experience expands rather than episodic with each lumpy, all-or-nothing decision.

41 Smaller, shorter-lead-time, more modular units tend to offer cheaper and more flexible options to planners seeking to minimize regret, because such resources can better adapt to and more cheaply guard against uncertainty about how the future will unfold.

42 Modular plants have off-ramps so that stopping the project is not a total loss: value can still be recovered from whatever modules were completed before the stop.

43 Distributed resources' physical portability will typically achieve a higher expected value than an otherwise comparable non-portable resource, because if circumstances change, a portable resource can be physically redeployed to a more advantageous location.

44 Portability also merits a more favorable discount rate because it is less likely that the anticipated value will not be realized—even though it may be realized in a different location than originally expected.

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45 A service provider or third-party contractor whose market reflects a diverse range of temporary or uncertain-duration service needs can maintain a "lending library" of portable distributed resources that can achieve high collective utilization, yet at each deployment avoid inflexible fixed investments that lack assurance of long-term revenue.

46 Modular, standardized, distributed, portable units can more readily be resold as commodities in a secondary market, so they have a higher residual or salvage value than corresponding monolithic, specialized, centralized, nonportable units that have mainly a demolition cost at the end of their useful lives.

47 The value of the resale option for distributed resources is further enhanced by their divisibility into modules, of which as many as desired may be resold and the rest retained to a degree closely matched to new needs.

48 Distributed resources typically do little or no damage to their sites, and hence minimize or avoid site remediation costs if redeployed, salvaged, or decommissioned.

49 Volatile fuel prices set by fluctuating market conditions represent a financial risk. Many distributed resources do not use fuels and thus avoid that costly risk.

50 Even distributed resources that do use fuels, but use them more efficiently or dilute their cost impact by a higher ratio of fixed to variable costs, can reduce the financial risk of volatile fuel prices.

51 Resources with a low ratio of variable to fixed costs, such as renewables and end-use efficiency, incur less cost volatility and hence merit more favorable discount rates.

52 Fewer staff may be needed to manage and maintain distributed generation plants: contrary to the widespread assumption of higher per-capita overheads, the small organizations required can actually be leaner than large ones.

53 Meter-reading and other operational overheads may be quite different for renewable and distributed resources than for classical power plants.

54 Distributed resources tend to have lower administrative overheads than centralized ones because they do not require the same large organizations with broad capabilities nor, perhaps, more complex legally mandated administrative and reporting requirements.

55 Compared with central power stations, mass-produced modular resources should have lower maintenance equipment and training costs, lower carrying charges on spare-parts inventories, and much lower unit costs for spare parts made in higher production runs.

56 Unlike different fossil fuels, whose prices are highly correlated with each other, non-fueled

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resources (efficiency and renewables) have constant, uncorrelated prices that reduce the financial risk of an energy supply portfolio.

57 Efficiency and cogeneration can provide insurance against uncertainties in load growth because their output increases with electricity demand, providing extra capacity in exactly the conditions in which it is most valuable, both to the customer and to the electric service provider.

58 Distributed resources are typically sited at the downstream (customer) end of the traditional distribution system, where they can most directly improve the system's lowest load factors, worst losses, and highest marginal grid capital costs—thus creating the greatest value.

59 The more fine-grained the distributed resource—the closer it is in location and scale to customer load—the more exactly it can match the temporal and spatial pattern of the load, thus maximizing the avoidance of costs, losses, and idle capacity.

60 Distributed resources matched to customer loads can displace the least utilized grid assets.

61 Distributed resource matched to customer loads can displace the part of the grid that has the highest losses.

62 Distributed resources matched to customer loads can displace the part of the grid that typically has the biggest and costliest requirements for reactive power control.

63 Distributed resources matched to customer loads can displace the part of the grid that has the highest capital costs.

64 Many renewable resources closely fit traditional utility seasonal and daily loadshapes, maximizing their "capacity credit"—the extent to which each kW of renewable resource can reliably displace dispatchable generating resources and their associated grid capacity.

65 The same loadshape-matching enables certain renewable sources (such as photovoltaics in hot, sunny climates) to produce the most energy at the times when it is most valuable—an attribute that can be enhanced by design.

66 Reversible-fuel-cell storage of photovoltaic electricity can not only make the PVs a dispatchable electrical resource, but can also yield useful fuel-cell byproduct heat at night when it is most useful and when solar heat is least available.

67 Combinations of various renewable resources can complement each other under various weather conditions, increasing their collective reliability.

68 Distributed resources such as photovoltaics that are well matched to substation peak load can precool the transfomer—even if peak load lasts longer than peak PV output—thus boosting

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substation capacity, reducing losses, and extending equipment life.

69 In general, interruptions of renewable energy flows due to weather can be predicted earlier and with higher confidence than interruptions of fossil-fueled or nuclear energy flows due to malfunction or other mishap.

70 Such weather-related interruptions of renewable sources also generally last for a much shorter time than major failures of central thermal stations.

71 Some distributed resources are the most reliable known sources of electricity, and in general, their technical availability is improving more and faster than that of centralized resources. (End-use efficiency resources are by definition 100% available—effectively, even more.)

72 Certain distributed generators' high technical availability is an inherent per-unit attribute—not achieved through the extra system costs of reserve margin, interconnection, dispersion, and unit and technological diversity required for less reliable central units to achieve the equivalent supply reliability.

73 In general, given reasonably reliable units, a large number of small units will have greater collective reliability than a small number of large units, thus favoring distributed resources.

74 Modular distributed generators have not only a higher collective availability but also a narrower potential range of availability than large, non-modular units, so there is less uncertainty in relying on their availability for planning purposes.

75 Most distributed resources, especially renewables, tend not only to fail less than centralized plants, but also to be easier and faster to fix when they do fail.

76 Repairs of distributed resources tend to require less exotic skills, unique parts, special equipment, difficult access, and awkward delivery logistics than repairs of centralized resources.

77 Repairs of distributed resources do not require costly, hard-to-find large blocks of replacement power, nor require them for long periods.

78 When a failed individual module, tracker, inverter, or turbine is being fixed, all the rest in the array continue to operate.

79 Distributed generation resources are quick and safe to work with: no post-shutdown thermal cooling of a huge thermal mass, let alone radioactive decay, need be waited out before repairs can begin.

80 Many distributed resources operate at low or ambient temperatures, fundamentally increasing safety and simplicity of repair.

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81 A small amount of energy storage, or simple changes in design, can disproportionately increase the capacity credit due to intermittent renewable resources.

82 Distributed resources have an exceptionally high grid reliability value if they can be sited at or near the customer's premises, thus risking less "electron haul length" where supply could be interrupted.

83 Distributed resources tend to avoid the high voltages and currents and the complex delivery systems that are conducive to grid failures.

84 Deliberate disruptions of supply can be made local, brief, and unlikely if electric systems are carefully designed to be more efficient, diverse, dispersed, and renewable.

85 By blunting the effect of deliberate disruptions, distributed resources reduce the motivation to cause such disruptions in the first place.

86 Distributed generation in a large, far-flung grid may change its fundamental transient-response dynamics from unstable to stable—especially as the distributed resources become smaller, more widespread, faster-responding, and more intelligently controlled.

87 Modular, short-lead-time technologies valuably temporize: they buy time, in a self-reinforcing fashion, to develop and deploy better technologies, learn more, avoid more decisions, and make better decisions. The faster the technological and institutional change, and the greater the turbulence, the more valuable this time-buying ability becomes. The more the bought time is used to do things that buy still more time, the greater the leverage in avoided regret.

88 Smaller units, which are often distributed, tend to have a lower forced outage rate and a higher equivalent availability factor than larger units, thus decreasing reserve margin and spinning reserve requirements.

89 Multiple small units are far less likely to fail simultaneously than a single large unit.

90 The consequences of failure are far smaller for a small than for a large unit.

91 Smaller generating units have fewer and generally briefer scheduled or forced maintenance intervals, further reducing reserve requirements.

92 Distributed generators tend to have less extreme technical conditions (temperature, pressure, chemistry, etc.) than giant plants, so they tend not to incur the inherent reliability problems of more exotic materials pushed closer to their limits—thus increasing availability.

93 Smaller units tend to require less stringent technical reliability performance (*e.g.*, failures per meter of boiler tubing per year) than very large units in order to achieve the same reliability (in

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this instance, because each small unit has fewer meters of boiler tubing)—thus again increasing unit availability and reducing reserves.

94 "Virtual spinning reserve" provided by distributed resources can replace traditional central-station spinning reserve at far lower cost.

95 Distributed substitutes for traditional spinning reserve capacity can reduce its operating hours —hence the mechanical wear, thermal stress, corrosion, and other gradual processes that shorten the life of expensive, slow-to-build, and hard-to-repair central generating equipment.

96 When distributed resources provide "virtual spinning reserve," they can reduce cycling, turn-on/shutdown, and low-load "idling" operation of central generating units, thereby increasing their lifetime.

97 Such life extension generally incurs a lower risk than supply expansion, and hence merits a more favorable risk-adjusted discount rate, further increasing its economic advantage.

98 Distributed resources can help reduce the reliability and capacity problems to which an aging or overstressed grid is liable.

99 Distributed resources offer greater business opportunities for profiting from hot spots and price spikes, because time and location-specific costs are typically more variable within the distribution system than in bulk generation.

100 Strategically, distributed resources make it possible to position and dispatch generating and demand-side resources optimally so as to maximize the entire range of distributed benefits.

101 Distributed resources (always on the demand side and often on the supply side) can largely or wholly avoid every category of grid costs on the margin by being already at or near the customer and hence requiring no further delivery.

102 Distributed resources have a shorter haul length from the more localized (less remote) source to the load, hence less electric resistance in the grid.

103 Distributed resources reduce required net inflow from the grid, reducing grid current and hence grid losses.

104 Distributed resources cause effective increases in conductor cross-section per unit of current (thereby decreasing resistance) if an unchanged conductor is carrying less current.

105 Distributed resources result in less conductor and transformer heating, hence less resistance.

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106 Distributed resources' ability to decrease grid losses is increased because they are close to customers, maximizing the sequential compounding of the different losses that they avoid.

107 Distributed photovoltaics particularly reduce grid loss load because their output is greatest at peak hours (in a summer-peaking system), disproportionately reducing the heating of grid equipment.

108 Such onpeak generation also reduces losses precisely when the reductions are most valuable.

109 Since grid losses avoided by distributed resources are worth the product of the number times the value of each avoided kWh of losses, their value can multiply rapidly when using area- and time-specific costs.

110 Distributed resources can reduce reactive power consumption by shortening the electron haul length through lines and by not going through as many transformers—both major sources of inductive reactance.

111 Distributed resources can reduce current flows through inductive grid elements by meeting nearby loads directly rather than by bringing current through lines and transformers.

112 Some end-use-efficiency resources can provide reactive power as a free byproduct of their more efficient design.

113 Distributed generators that feed the grid through appropriately designed DC-to-AC inverters can provide the desired real-time mixture of real and reactive power to maximize value.

114 Reduced reactive current improves distribution voltage stability, thus improving end-use device reliability and lifetime, and enhancing customer satisfaction, at lower cost than for voltage-regulating equipment and its operation.

115 Reduced reactive current reduces conductor and transformer heating, improving grid components' lifetime.

116 Reduced reactive current, by cooling grid components, also makes them less likely to fail, improving the quality of customer service.

117 Reduced reactive current, by cooling grid components, also reduces conductor and transformer resistivity, thereby reducing real-power losses, hence reducing heating, hence further improving component lifetime and reliability.

118 Reduced reactive current increases available grid and generating capacity, adding to the capacity displacement achieved by distributed resources' supply of real current.

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119 Distributed resources, by reducing line current, can help avoid voltage drop and associated costs by reducing the need for installing equipment to provide equivalent voltage support or step-up.

120 Distributed resources that operate in the daytime, when sunlight heats conductors or transformers, help to avoid costly increases in circuit voltage, reconductoring (replacing a conductor with one of higher ampacity), adding extra circuits, or, if available, transferring load to other circuits with spare ampacity.

121 Substation-sited photovoltaics can shade transformers, thereby improving their efficiency, capacity, lifetime, and reliability.

122 Distributed resources most readily replace distribution transformers at the smaller transformer sizes that have higher unit costs.

123 Distributed resources defer or avoid adding grid capacity.

124 Distributed resources, by reducing the current on transmission and distribution lines, free up grid capacity to provide service to other customers.

125 Distributed resources help "decongest" the grid so that existing but encumbered capacity can be freed up for other economic transactions.

126 Distributed resources avoid the siting problems that can occur when building new transmission lines.

127 These siting problems tend to be correlated with the presence of people, but people tend to correlate with both loads and opportunities for distributed resources.

128 Distributed resources' unloading, hence cooling, of grid components can disproportionately increase their operating life because most of the life-shortening effects are caused by the highest temperatures, which occur only during a small number of hours.

129 More reliable operation of distribution equipment can also decrease periodic maintenance costs and outage costs.

130 Distributed resources' reactive current, by improving voltage stability, can reduce tapchanger operation on transformers, increasing their lifetime.

131 Since distributed resources are nearer to the load, they increase reliability by reducing the length the power must travel and the number of components it must traverse.

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132 Carefully sited distributed resources can substantially increase the distribution system operator's flexibility in rerouting power to isolate and bypass distribution faults and to maintain service to more customers during repairs.

133 That increased delivery flexibility reduces both the number of interrupted customers and the duration of their outage.

134 Distributed generators can be designed to operate properly when islanded, giving local distribution systems and customers the ability to ride out major or widespread outages.

135 Distributed resources require less equipment and fewer procedures to repair and maintain the generators.

136 Stand-alone distributed resources not connected to the grid avoid the cost (and potential ugliness) of extending and connecting a line to a customer's site.

137 Distributed resources can improve utility system reliability by powering vital protective functions of the grid even if its own power supply fails.

138 The modularity of many distributed resources enables them to scale down advantageously to small loads that would be uneconomic to serve with grid power because its fixed connection costs could not be amortized from electricity revenues.

139 Many distributed resources, notably photovoltaics, have costs that scale far more closely to their loads than do the costs of distribution systems.

140 Distributed generators provide electric energy that would otherwise have to be generated by a centralized plant, backed up by its spinning reserve, and delivered through grid losses to the same location.

141 Distributed resources available on peak can reduce the need for the costlier to-keep-warm centralized units.

142 Distributed resources very slightly reduce spinning reserves' operational cost.

143 Distributed resources can reduce power stations' startup cycles, thus improving their efficiency, lifetime, and reliability.

144 Inverter-driven distributed resources can provide extremely fast ramping to follow sudden increases or decreases in load, improving system stability and component lifetimes.

145 By combining fast ramping with flexible location, often in the distribution system, distributed resources may provide special benefits in correcting transients locally before they

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propagate upstream to affect more widespread transmission and generating resources.

146 Distributed resources allow for net metering, which in general is economically beneficial to the distribution utility (albeit at the expense of the incumbent generator).

147 Distributed resources may reduce utilities' avoided marginal cost and hence enable them to pay lower buyback prices to Qualifying Facilities.

148 Distributed resources' ability to provide power of the desired level of quality and reliability to particular customers—rather than just a homogeneous commodity via the grid—permits providers to match their offers with customers' diverse needs and to be paid for that close fit.

149 Distributed resources can avoid harmonic distortion in the locations where it is both more prevalent (*e.g.*, at the end of long rural feeders) and more costly to correct.

150 Certain distributed resources can actively cancel harmonic distortion in real time, at or near the customer level.

151 Whether provided passively or actively, reduced harmonics means lower grid losses, equipment heating (which reduces life and reliability), interference with end-user and grid-control equipment, and cost of special harmonic-control equipment.

152 Appropriately designed distributed inverters can actively cancel or mitigate transients in real time at or near the customer level, improving grid stability.

153 Many distributed resources are renewable, and many customers are willing to pay a premium for electricity produced from a non-polluting generator.

154 Distributed resources allow for local control of generation, providing both economic-development and political benefits.

155 Certain distributed nonelectric supply-side resources such as daylighting and passive ventilation can valuably improve non-energy attributes (such as thermal, visual, and acoustic comfort), hence human and market performance.

156 Bundling distributed supply- with demand-side resources increases many of distributed generation's distributed benefits per kW, *e.g.*, by improving match to loadshape, contribution to system reliability, or flexibility of dispatching real and reactive power.

157 Bundling distributed supply- with demand-side resources means less supply, improving the marketability of both by providing more benefits (such as security of supply) per unit of cost.

158 Bundling distributed supply- with demand-side resources increases the provider's profit or

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price flexibility by melding lower supply-side with higher demand-side margins.

159 Certain distributed resources can valuably burn local fuels that would otherwise be discarded, often at a financial and environmental cost.

160 Distributed resources provide a useful amount and temperature of waste heat conveniently close to the end-use.

161 Photovoltaic (or solar-thermal) panels on a building's roof can reduce the air conditioning load by shading the roof—thus avoiding air-conditioner and air-handling capacity, electricity, and the capacity to generate and deliver it, while extending roof life.

162 Some distributed resources like microturbines produce carbon dioxide, which can be used as an input to greenhouses or aquaculture farms.

163 Some types of distributed resources like photovoltaic tiles integrated into a roof can displace elements of the building's structure and hence of its construction cost.

164 Distributed resources make possible homes and other buildings with no infrastructure in the ground—no pipes or wires coming out—thus saving costs for society and possibly for the developer.

165 Because it lacks electricity, undeveloped land may be discounted in market value by more than the cost of installing distributed renewable generation—making that power source better than free.

166 Since certain distributed resources don't pollute and are often silent and inconspicuous, they usually don't reduce, and may enhance, the value of surrounding land—contrary to the effects of central power plants.

167 Some distributed resources can be installed on parcels of land that are too small, steep, rocky, odd-shaped, or constrained to be valuable for real-estate development.

168 Some distributed resources can be double-decked over other uses, reducing or eliminating net land costs. (Double-decking over utility substations, etc., can also yield valuable shading benefits that reduce losses (# 168) and extend equipment life.)

169 The shading achieved by double-decking PVs above parked cars or livestock can yield numerous private and public side-benefits.

170 Distributed resources may reduce society's subsidy payments compared with centralized resources.

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171 Distributed resources can significantly—and when deployed on a large scale can comprehensively and profoundly—improve the resilience of electricity supply, thus reducing many kinds of social costs, risks, and anxieties, including military costs and vulnerabilities.

172 Technologies perceived as benign in their local impacts make siting approvals more likely, reducing the risk of project failure and lost investment and hence reducing the risk premium demanded by investors.

173 Technologies perceived as benign or de minimis in their local impacts can often also receive siting approvals faster, or can even be exempted from approvals processes, further shortening construction time and hence reducing financial cost and risk.

174 Technologies perceived as benign in their local impacts have wide flexibility in siting, making it possible to shop for lower-cost sites.

175 Technologies perceived as benign in their local impacts have wide flexibility in siting, making it easier to locate them in the positions that will maximize system benefits.

176 Siting flexibility is further increased where the technology, due to its small scale, cogeneration potential, and perhaps nonthermal nature, requires little or no heat sink.

177 Distributed resources' local siting and implementation tend to increase their local economic multiplier and thereby further enhance local acceptance.

178 Distributed resources can often be locally made, creating a concentration of new skills, industrial capabilities, and potential to exploit markets elsewhere.

179 Most well-designed distributed resources reduce acoustic and aesthetic impacts.

180 Distributed resources can reduce irreversible resource commitments and their inflexibility.

181 Distributed resources facilitate local stakeholder engagements and increase the community's sense of accountability, reducing potential conflict.

182 Distributed resources generally reduce and simplify public health and safety impacts, especially of the more opaque and lasting kinds.

183 Distributed resources are less liable to the regulatory "ratcheting" feedback that tends to raise unit costs as more plants are built and as they stimulate more public unease.

184 Distributed resources are fairer, and seen to be fairer, than centralized resources because their costs and benefits tend to go to the same people at the same time.

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185 Distributed resources have less demanding institutional requirements, and tend to offer the political transparency and attractiveness of the vernacular.

186 Distributed resources lend themselves to local decisions, enhancing public comprehension and legitimacy.

187 Distributed resources are more likely than centralized ones to respect and fit community and jurisdictional boundaries, simplifying communications and decision-making.

188 Distributed resources better fit the scale of communities' needs and ability to address them.

189 Distributed resources foster institutional structure that is more weblike, learns faster, and is more adaptive, making the inevitable mistakes less likely, consequential, and lasting.

190 Distributed resources' smaller, more agile, less bureaucratized institutional framework is more permeable and friendly to information flows inward and outward, further speeding learning.

191 Distributed resources' low cost and short lead time for experimental improvement encourages and rewards more of it and hence accelerates it.

192 Distributed resources' size and technology (frequently well correlated) generally merit and enjoy a favorable public image that developers, in turn, are generally both eager and able to uphold and enhance, aligning their goals with the public's.

193 With some notable exceptions such as dirty engine generators, distributed resources tend to reduce total air emissions per unit of energy services delivered.

194 Since distributed resources' air emissions are directly experienced by the neighbors with the greatest influence on local acceptance and siting, political feedback is short and quick, yielding strong pressure for clean operations and continuous improvement.

195 Due to scale, technology, and local accountability informed by direct perception, the rules governing distributed resources are less likely to be distorted by special-interest lobbying than those governing centralized resources.

196 Distributed utilities tend to require less, and often require no, land for fuel extraction, processing, and transportation.

197 Distributed resources' land-use tends to be temporary rather than permanent.

198 Distributed resources tend to reduce harm to fish and wildlife by inherently lower impacts and more confined range of effects (so that organisms can more easily avoid or escape them).

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199 Some distributed resources reduce and others altogether avoid harmful discharges of heat to the environment.

200 Some hydroelectric resources may be less harmful to fish at small than at large scale.

201 The greater operational flexibility of some distributed resources, and their ability to serve multiple roles or users, may create new opportunities for power exchange benefiting anadromous fish.

202 Well-designed distributed resources are often less materials- and energy-intensive than their centralized counterparts, comparing whole systems for equal delivered production.

203 Distributed resources' often lower materials and energy intensity reduces their indirect or embodied pollution from materials production and manufacturing.

204 Many distributed resources' reduced materials intensity reduces their indirect consumption of depletable mineral resources.

205 The small scale, standardization, and simplicity of most distributed resources simplifies their repair and may improve the likelihood of their remanufacture or recycling, further conserving materials.

206 Many distributed resources withdraw and consume little or no water.

207 Many distributed resources offer psychological or social benefits of almost infinite variety to users whose unique prerogative it is to value them however they choose.

Site Map

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Canadian Renewable Energy Alliance

promoting a transition to renewable energy

Distributed Generation in Canada -
Maximizing the benefits of renewable resources

August 2006

This paper is one of eight background reports on the Canadian Renewable Energy Alliance's model framework and recommendations for a comprehensive Canadian renewable energy strategy. This paper includes recommendations for provincial energy efficiency and conservation policies and for actions backed up by national enabling measures and international participation.

For information on the recommendations contained in this paper, contact **Alex Doukas** at **the Ontario Sustainable Energy Asssociation**: alex@ontario-sea.org

The Canadian Renewable Energy Alliance (CanREA) is an alliance of Canadian civil society organizations from the non-profit or voluntary sector that share an interest in maximizing energy efficiency and conservation and promoting a global transition to low-impact renewable energy. Members of CanREA believe that this transition is needed to address global climate change, pollution, global energy supply, human security, poverty eradication and economic sustainability. CanREA recognizes that our window of opportunity is limited and that this global transition must begin now through individual country action, international co-operation and a range of innovative market instruments, regulatory measures, public education efforts and voluntary actions.

The organizations actively involved in the formation of CanREA include:

- Canadian Association for Renewable Energies
- BC Sustainable Energy Association
- The David Suzuki Foundation
- Falls Brook Centre
- The Halifax Initiative
- One Sky—The Canadian Institute for Sustainable Living
- The Ontario Sustainable Energy Association
- The Pembina Institute
- Pollution Probe
- The Saskatchewan Environmental Society
- The Sierra Youth Coalition
- STORM Coalition

For more information on CanREA and its members, visit our website at **www.canrea.ca**

Distributed Generation in Canada -
Maximizing the benefits of renewable resources

1. Distributed Generation in Canada

Renewable energy sources are rapidly becoming a key contributor to Canada's electricity supply mix. As the nation's energy infrastructure ages, moving towards clean and inexhaustible sources of electricity is becoming a precondition of Canada's continued economic success in a competitive global market. Social, health and environmental constraints are fuelling a shift in national and regional energy policy, not only in Canada, but around the world.

Historically, energy policy in Canada has emphasized large centralized electricity generation and long-distance, high-voltage transmission from centralized sources such as large-scale hydro, coal, natural gas and nuclear power plants. Canada's aging centralized energy infrastructure is becoming more problematic as demand for clean, reliable and affordable electricity generation grows. North America's centralized grid system, stressed to its limits,[1] has become vulnerable, increasingly brittle,[2] and inefficient. Over-reliance on large, polluting and expensive generation and transmission is no longer an option that Canadians will endorse. More and more frequently, centralized generation is being supplemented or replaced by distributed generation (DG), a new way of thinking about electricity generation, transmission and distribution. The market share of renewable DG continues to grow, and shows no signs of slowing.

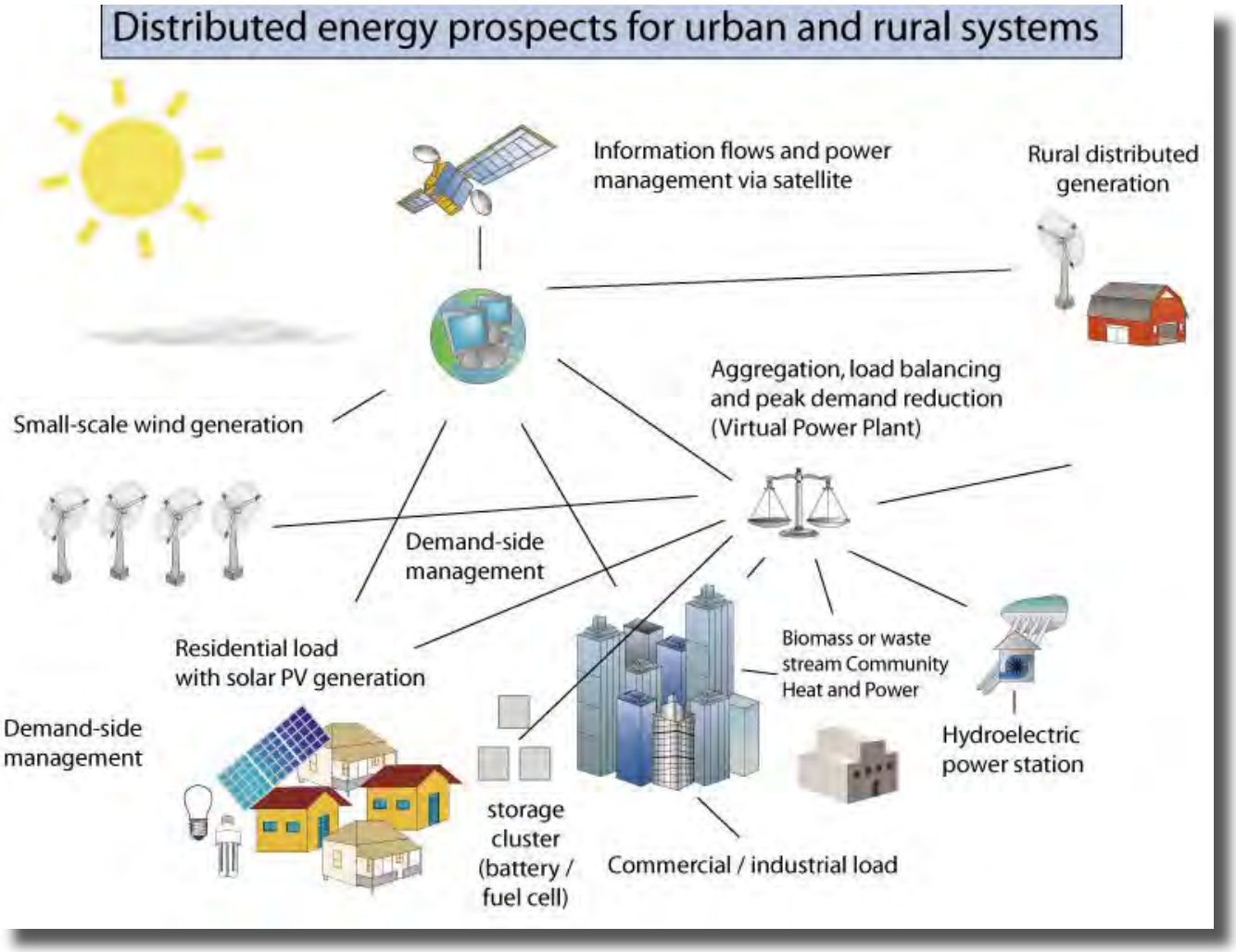
Over the past 15 years, a number of factors have helped to push DG to the fore of electricity generation: new innovations in DG technologies, the liberalization of electricity markets generally allowing for the participation of more generators, growing concern around climate change and increasing consumer demand coupled with environmental and social constraints on the construction of new transmission infrastructure have all combined to make renewable DG an appealing option.[3] As of 2005, fully 25% of new electricity generation installed came from distributed resources, compared to only 13% in 2002.[4] To be on the leading edge of this growth trend, all levels of government, along with several other actors, must adapt to a rapidly changing electricity market.

Several provinces, including Ontario, Quebec, Nova Scotia, P.E.I. and B.C., are either currently undergoing or have recently undergone reviews of their long-term energy strategies. The opportunity for these provinces and for Canada to take advantage of distributed electricity generation is considerable, and while the provincial strategies are diverse, each expects that renewable technologies will play a significant role in electricity generation. At the federal level, Canada has made a commitment to reduce carbon dioxide emissions by 6% below 1990 levels between 2008-2012 as a party to the Kyoto Protocol.[5] This commitment will require a major overhaul of electricity generation in Canada; in 2005, Environment Canada reported that electricity and heat generation were responsible for emitting 133 000 kilotonnes of carbon dioxide, a number which increased to 202 000 kilotonnes, or more than a third of Canada's total emissions in 2003 when all energy use and energy industries are considered.[6] To achieve Canada's climate change goal, it is clear that we need to embark on a sustainable energy path that includes policies promoting low-impact renewable technologies.[7]

To realize the potential benefits of distributed generation and renewable energy fully requires not only a new way of thinking about electricity generation, but a new way of thinking about electricity transmission and distribution. An economically, environmentally and socially sustainable energy future will require aggressive adoption of DG technologies and planning practices. DG is a model of electricity generation that allows for thousands of decentralized, small-scale generators. The World Alliance for Decentralized Energy describes DG as "electricity production at or near the point of use".[8] Renewable energy technologies, one of the critical elements of a sustainable future for Canada, are typically modular and are better suited to less environmentally damaging,

distributed applications than larger conventional methods of electricity generation.[9] DG and renewable energy are closely linked, as the transition to renewable energy sources will result in a shift towards less centralized generation and grids as has been the case in Europe due to the nature of renewable technologies. By promoting an integrated approach to innovation in electricity generation as well as grid infrastructure and design, the benefits of renewable energy and DG can both be synergistically maximized. Figure 1, below, illustrates how a grid adapted to DG might appear.

Figure 1
Symbols for diagrams courtesy of the Integration and Application Network (ian.umces.edu/symbols), University of Maryland Center for Environmental Science.



The benefits offered by DG can be grouped into three closely linked and often overlapping categories: economic benefits, environmental benefits, and social benefits. Below, some of these benefits are described, with a particular focus on the economic impacts of DG.

2. Economic benefits

There is a strong economic case that supports the rapid deployment of DG technologies; indeed, there are many reasons that DG has grown to represent 25% of all new generation in 2005.[10] At the forefront are the technical and electrical engineering-related savings that can be achieved through DG: according to the International Energy Agency, broad deployment of DG could result in cost savings of nearly 30% of total electricity costs by

mitigating transmission and distribution losses and displacing expensive infrastructure.[11] translating to hundreds of billions of dollars worldwide, and tens of billions of dollars in Canada alone. One of the economic benefits of DG is reduced transmission loss, or a significant reduction of the electricity wasted in the transmission of electric power over long distances. In 1995, transmission and distribution losses were estimated at 7.2% of total electricity generation in the United States.[12] Canada's grid architecture and infrastructure is similar to that of the United States, and it would not be unreasonable to speculate that a similar figure would apply in Canada, although precise data on this element of grid efficiency is lacking. It is important to note that grid-connected DG will still have losses associated with distribution; however, these costs are significantly lower than in a centralized, long-distance grid system, as emphasized by the IEA's estimate cited above of 30% lower total costs through DG as opposed to centralized generation.

Recently, increasing congestion on transmission lines that have been stretched to their maximum carrying capacity has resulted in even greater transmission losses as electricity demand grows.[13] North America's aging power grids are rapidly becoming more susceptible to congestion along transmission lines. The case of PJM Interconnection provides a pertinent illustration of this issue. PJM, the regional transmission organization largely responsible for the transmission of electricity throughout the Eastern U.S., estimated the costs associated with transmission congestion to be approximately U.S. $65 million in 1999. By 2004, congestion costs had risen to nearly U.S. $800 million, with 2005 costs estimated to be over U.S. $1 billion.[14] To relieve congestion, American Electric Power plans to build a new 765 kV transmission line for almost $3 billion.[15] Typically, DG is sited near end-users, where they can closely mirror customer loads and limit line losses while mitigating grid capital costs related to transmission.

Another constraint of long-distance transmission that can have adverse economic impacts is the reliability of electricity distribution in North America. When demand increases during hot weather, power lines heat up and sag, not only from the increased electricity flowing through the lines, but also from the warmer ambient temperatures and from solar thermal energy heating the black-sheathed transmission cables. This problem can pose a serious threat to system security; two of North America's more recent major blackouts, those in 1996 and 2003, were caused by overloaded lines sagging into trees, resulting in short circuits that precipitated a larger collapse of the electrical grid. [16] Just as electricity is needed most to provide relief for vulnerable individuals during periods of extreme temperatures, it is least available due to the constraints of the existing transmission system and centralized grid configuration. The costs of the 2003 North American blackout alone have been estimated variously to be between $4 billion and $10 billion. [17], [18]

Certain centralized generators are also more vulnerable to failure during extreme conditions due to technical constraints; during the European heat waves, centralized nuclear reactors must limit their output because of high temperatures.[19] Just when their electricity is in high demand, the large, centralized reactors were least able to respond to demand and had to decrease energy production to avoid collapse from overheating. Extraordinary measures were employed to avoid shutdowns, including the spraying of concrete buildings that housed reactors with water to cool them. Even this was not enough, and one of the reactors at the Fessenheim nuclear plant in Germany had to be shut down over concerns surrounding its stability.[20] Reactors also received special governmental permission to discharge water used as a reactor coolant into rivers at temperatures beyond an acceptable threshold established to ensure the safety of aquatic life, endangering fish populations. [21]
Because of its susceptibility to such failures, critics have often described North America's power grid as a "brittle" grid. The Electricity Consumers Resource Council was critical of the tenuous reliability of the grid that the 2003 blackout brought to light: "from a public policy perspective—in the U.S. or Canada—it really does not matter if the total economic damages are $4 billion, $6 or $10 billion, or anywhere in between. The point is that this type of event is unconscionable to the extent that a single utility's failure to properly trim trees is deemed the 'root cause' of the August 14 Blackout."

Such criticisms are not isolated, nor are they novel. As far back as 1981, in *Brittle Power*, an examination of energy security in the United States and North America, experts noted that the North American power grid "interconnects the units rather sparsely, with heavy dependence on a few critical links and nodes;" and that the grid tends to "knit the interconnected units into a synchronous system in such a way that it is difficult for a section to continue to operate if it becomes isolated—that is, since each unit's operation depends significantly

on the synchronous operation of other units, failures tend to be systemwide." [22] The decentralization of electricity generation can greatly reduce the damage and disturbance caused by systemwide grid failure and catastrophic power interruptions through the implementation of microgrid systems (described briefly in the "best practices" section of this paper) which can safely provide power from DG to nearby loads during periods of general system failure. When centralized failures do occur, DG can also make positive contributions to restarting the power system, reducing downtime; as modular units, they tend to be far easier to restart that centralized units that rely on energy-intensive startup procedures. These benefits of DG are very valuable, but their degree of efficacy can vary significantly depending on how DG is deployed. Models already exist that can aid planners in quantifying the benefits of DG in particular applications to thereby improve grid planning and electricity supply decisions. [23]

DG offers numerous economic benefits beyond simply reducing line losses and improving system reliability or security. While certain applications of small-scale DG can result in diseconomies of scale, other applications may be far more economically efficient than centralized generation. Additionally, by being situated closer to loads, DG also extends the lifetime of both distribution / transmission and end-use devices, the former through reduced reactive current that helps to keep grid components cool and the latter through improving distribution voltage stability, which can very depending on the DG technologies used. [24]

In addition, DG can be implemented much faster to match generation and demand better than new centralized generation due to its modular nature. Unlike centralized generation plants, DG systems can closely match changes in projected demand achieved through conservation and efficiency strategies. Modular DG also has lower lead-times than most centralized generation, which translates to less financial risk from burgeoning cost overruns, reduced financial risk of under- or over-building in a volatile electricity market, and therefore leads to less financial exposure. It also results in less capital being tied up at any given time prior to a plant generating revenue. This means that costs can be recouped more quickly and debt can be repaid earlier, increasing the value of projects to investors. The smaller scale of DG power plants can also encourage streamlined permitting and planning processes, which means fewer project failures, and less risk to capital investors. Because the flexibility in siting DG is also greater than centralized generators, DG can service areas where a connection to transmission may be entirely uneconomical, eliminating the need for a costly interconnection or uneconomical expansion of transmission lines. [25]

The figures below illustrate some of the economic benefits of infrastructure deferral afforded by certain DG applications. Figure 2 shows a typical response to increasing load: constructing new centralized generation and expanding the transmission and distribution infrastructure. Figure 3 illustrates the costs avoided by scaling DG to meet the growing load.

Figure 2
Typical response to electricity demand growth

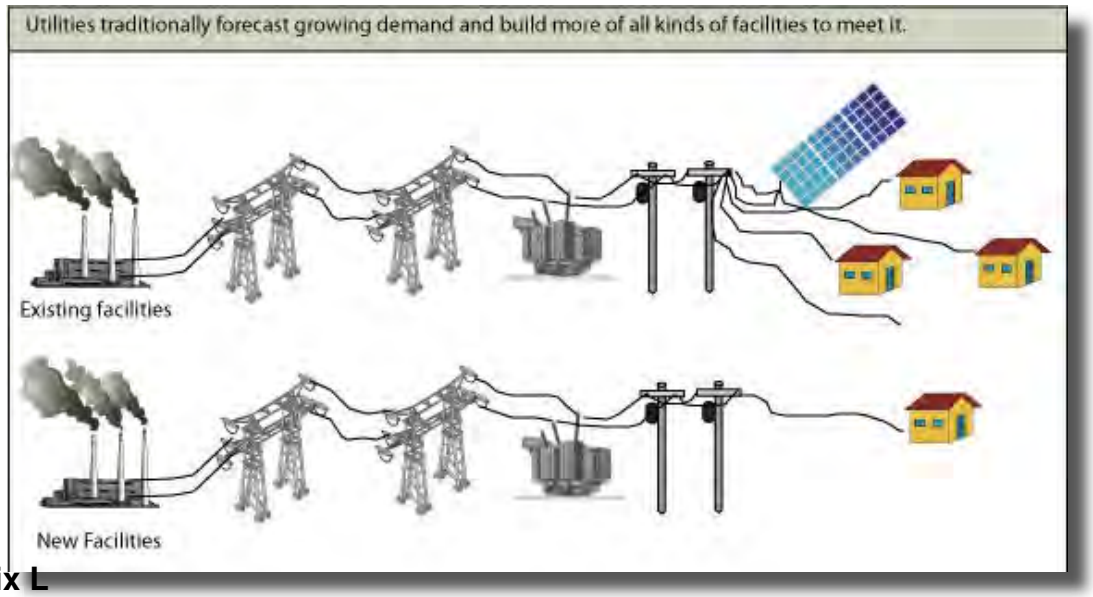
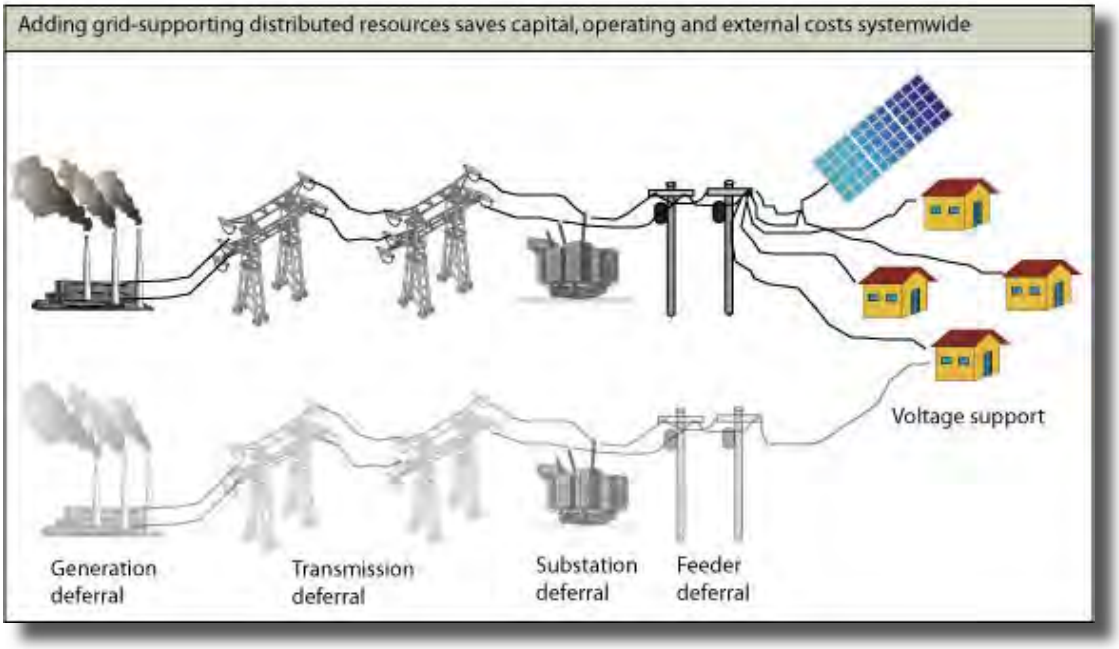


Figure 3
Transmission and infrastructure deferment as a result of DG deployment
Figures 2 and 3 adapted from: Lovins, A. et al. *Small is profitable: The hidden economic benefits of making electric resources the right size*. Snowmass: Rocky Mountain Institute. 2002.



Another major benefit of DG is the opportunity it presents for community economic development. DG allows communities to participate in electricity generation, creating jobs and stimulating local economies. Community-owned renewable energy can generate many times the economic activity of commercial development, keeping more energy dollars in communities. It can also provide significant alternative revenue streams for farmers and rural landowners. For more information in the economic impacts of DG in the context of community-based power projects, see the CanREA paper on community power in this series.

Combined heat and power (CHP) systems can also become even more financially attractive than they already are as the challenges facing DG are addressed. In CHP plants that use renewable fuel sources, biomass from crop residues, livestock byproducts, and other waste streams can be used to generate both electricity and heat. Not only does this increase generation capacity, but it also can assist in the management of crop residues that might normally be considered waste and have an associated disposal cost. Both the heat and the electricity generated by CHP systems are distributed to nearby end-users. When considering CHP applications for DG, it is important to carefully assess the environmental impacts of available technologies. Natural gas, for example, is not a renewable source of energy, and its combustion results in significant carbon dioxide releases.

When the multitude of economic advantages DG enjoys over centralized generation are viewed in their entirety, it should be unsurprising that the benefits of DG can increase the value of renewable energy resources by nearly a factor of ten. [26] While the economic argument for the rapid and extensive deployment of DG is strong enough to stand on its own merits, environmental and social benefits can also add significant value to renewable energy projects.

3. Environmental benefits

DG has the potential to greatly benefit the environment by reducing the need for ecologically disruptive centralized generation. The implications of DG deployment for renewable energy may well be the most significant environmental benefit conferred by DG. If changes to the generation, transmission and distribution system

are made that facilitate DG, more renewable generators in more areas are sure to follow. From an ecological standpoint, it is critical that DG take the form of clean renewable energy that is minimally polluting. The electrical engineering and transmission and distribution benefits that accrue from DG are extremely valuable, but could be quickly negated by increased environmental impacts from diesel and natural gas generators that either release carbon dioxide, nitrous oxides, and sulphur dioxide or contribute those emissions during fuel processing. To be sustainable, DG must come in the form of renewable and clean sources, including wind, solar, and low-impact hydropower, along with sustainable biomass combustion. The environmental benefits of renewable energy are described in depth in the paper in this series that discusses Green Power, available through the Canadian Renewable Energy Alliance.

Additionally, smaller generation units in general tend to meet with more support than larger centralized generators. [27] Small clusters of two or three megawatt-scale wind turbines distributed in hundreds of locations tend to meet with a more favourable reaction from local residents than projects at scales of hundreds of megawatts. An increased acceptance of renewable technologies by local people will result in fewer barriers to the growth of renewables, increasing their positive impact on emissions profiles and their mitigation of extractive resource exploitation. Further, smaller-scale projects, when properly sited, tend to have less severe environmental impacts than fewer scaled-up projects using the same technology. Small run-of-the-river hydro projects tend to be less harmful to aquatic life, particularly fish populations, than larger scale hydroelectric generation. Embedded generation, such as the installation of solar photovoltaics on a roof, will minimize the environmental impacts of electricity generation by utilizing existing building envelopes efficiently.

By increasing the efficiency of energy transmission, DG can also reduce the overall demand for electricity, reducing not only the number of new generators but also the transmission and distribution infrastructure required for the delivery of electricity. Eliminating these structures also eliminates their potential environmental impacts, further increasing the attractiveness of DG from an environmental perspective. Offsetting the impacts of siting new transmission and distribution infrastructure is a significant opportunity presented by increasing the percentage of DG relative to centralized generation.

4. Social benefits

Due to the centralized nature of North American power grids, electricity sources “tend to lack the qualities of user controllability, comprehensibility, and user-independence”. [28] Essentially, this means that individuals and communities are unable to participate in electricity generation, resulting in a process that seems almost mystical to those who rely on electricity. Because DG allows for the rapid expansion of community-based electricity generation, many of the social benefits arising from community power are also a function of DG. Community power promotes awareness of the source of electricity generation, and encourages community participation in electricity generation; this in turn facilitates a more profound understanding of the impacts of electricity use and consumption. It has been demonstrated in the case of biomass plants that bottom-up decision-making that consults the public extensively can help to increase acceptance of new generation through the integration of their input during the project development phase. [29] Community-owned and controlled DG also tends to be more acceptable to local people from a siting perspective than large, centralized power plants.

Through community power, DG can help Canadians to better understand the value of renewable energy in reducing environmental impacts, stimulating community economic development, and forging stronger community ties. DG facilitates community economic development spurred by new renewable generation capacity at the community scale, and subsequently it encourages sustainable local development, allowing communities to retain more of their energy dollars.

The smaller components and human-scale nature of DG can also help people relate to electricity generation better than with centralized generators which may be incomprehensible and difficult to interact with in a meaningful way due to their complexity. Subsequently, rules and regulations governing not less susceptible to cooption by special interest groups than those elected to govern. [30] This can help lead to a more equitable model of electricity generation, where the benefits are dispersed as widely as the generators and end-users, directly

benefiting more Canadians.

DG's many diverse benefits make it an attractive option for the incremental replacement of a significant portion of centralized generation as aging power plants are taken offline. There are a number of considerations that play an important role in the effectiveness of DG applications, from grid design to city planning. In Canada, several barriers that prevent or disencentivize the deployment of renewable DG remain in place

5. Challenges to DG

Even for appropriate and sustainable applications of DG, barriers to development remain. For decades, centralized generation has been the dominant standard in North America and throughout the world. Tens of billions of dollars of cumulative investment has been poured into Canada's centralized infrastructure; as a result of this massive-scale investment, existing infrastructure and institutions are focused on the heavily centralized model of generation despite the advances in DG that have made it a financially, socially and environmentally attractive alternative. Because of the accumulated investment in the existing power system, DG often must adapt to existing systems in order to connect to the grid. While this is quite possible within the constraints of the centralized power system, DG may face unnecessarily burdensome requirements in their siting, interconnection to the grid, and their operation. Currently, grid-connected generators must be able to determine when the system as a whole is failing, and be able to disconnect at a moment's notice to allow utilities to resolve problems along the line and carry out necessary repairs. [31]

The primary concern that arises during a system failure that requires repairs relates to "islanding", where a generator will continue to produce power, electrifying an area of the distribution system even after other generators have taken their supply off-line. This situation can endanger not only generators and the distribution system, but can also imperil utility workers performing repairs to bring a system back online. [32] There are some answers to the grid conundrum that can hep to can be largely addressed through the implementation of microgrids. To the centralized grid, microgrids appear as any other customer. They can change between operating on or off of the central grid, and easily isolate themselves in the event of a systemwide failure to avoid islanding issues and to continue to provide power to the microgrid-serviced load. Microgrids can also shed nonessential load during periods of system strain or power shortage to avoid brownouts or blackouts and declines in power quality, while impacting the end-user only minimally. This can protect critical systems like computers systems and communications equipment that have become crucial to the functioning of our economy. [33]

Another concern that applies only to certain distributed renewable technologies is their variability. Wind turbines in particular are susceptible to high degrees of variability; they do not produce electricity when the wind does not blow. This is not so much a problem for DG, however, as it is an opportunity. As the British Wind Energy Association points out, **"**there is little overall impact if the wind stops blowing somewhere – it is always blowing somewhere else," and also that "[t]he more wind farms that are built over a wider geographical location, the more reliable wind energy is". [34] A 2005 study carried out by dena, the German Energy Agency, found that the wind capacity in Germany could be expanded up to as much as 36 000 MW by 2015 "without the addition of new plants to provide operational reserve." [35] Other options are available to mitigate potential problems include 'virtual utilities', describe in the "Best practices and future considerations" section below, that are capable of aggregating and dispatching distributed loads and generation may also play a role in mitigating the variability of wind in areas where variability has more sever impacts on the power system as a whole.

In order to deploy DG rapidly and constructively, Canada must overcome these challenges by utilizing technologies and management strategies that have already been developed. To ease the transition to DG in Canada, practitioners and policymakers can consider the adoption of several beneficial practices that have already been demonstrated successfully worldwide.

6. Best practices and future considerations

Several regions of the world have already begun a shift in earnest away from centralized generation toward DG. In much of Western Europe, extensive deployment of DG is already underway. To facilitate the shift toward renewable DG technologies and to promote their further growth, several European nations are working collaboratively through the EU to transform existing infrastructure into a system that captures all of the benefits of renewable DG. The SmartGrid Technology Platform involves research on technical and regulatory issues surrounding Europe's power system. In Europe, the integration of distributed resources with the power system is becoming increasingly important as the proportion of small generating systems increases, a multi-stakeholder effort to develop a new vision for electricity distribution and transmission networks. Participants include industry representatives, transmission and distribution system operators, research bodies and regulators. [36]

A major component of the smart grid vision is a fully computer-integrated power system, one that is responsive both to consumer and generator demands. Smart digital micromanagement of the power system allows for much more flexibility in both load and generation control, increasing the overall efficiency of grid operations while allowing for a far larger penetration of distributed resources than a brittle centralized system might be able to withstand. The SmartGrid vision intends to develop a toolkit of technical solutions that will address barriers to DG that can be applied in a cost-effective way, while helping to establish a uniform regulatory and standard technical climate for renewables throughout Europe to enable the transfer of electricity across borders. Ultimately, the Platform aims to integrate the emerging model of DG and the existing model of centralized generation through the deployment of new grid equipment that will help to ensure system reliability while streamlining control arrangements.

The SmartGrid Platform attempts to address a problem common to transmission and distribution networks. Because they tend to be so large-scale and expensive, transmission and distribution networks are often extremely limited by regulation, or their controlling interests have a natural monopoly with little or no viable competition, resulting in a disincentive to innovation. Even in a liberalized energy market, electricity distribution networks tend to act as natural monopolies due to their massive scale in a system that emphasizes centralized generation, and are thus regulated by an independent systems operator or through some other centralized institution.

LDCs and utilities, the groups that largely determine the practical shape of the power system, almost always act to maximize profits, and are hesitant to take risks in an environment where a natural monopoly exists. Despite these circumstances, the rapid growth of DG will require system operators to manage networks to actively moderate the grid rather than merely responding to situations when difficulties arise. To achieve a degree of precision may require the deployment of distributed computing, virtual utilities, and microgrids. To encourage these endeavours, regulatory bodies should provide incentives for grid innovation. Through their Innovation Funding Incentive, Britain's gas and electricity regulator already provides incentives for operators of distributed networks who innovate through applied research, development and deployment of new network technologies that facilitate DG.

To properly implement Smart Grids, Canada will have to capitalize on advancements in both distributed computing and power electronics. For example, in a Smart Grid system, the degree of micromanagement of both loads and generators will likely require sophisticated balancing systems capable of a high level of responsiveness. This is likely to result in the development of a concept often described as the 'virtual utility' or 'virtual power plant'. The virtual power plant is not a power plant in the traditional sense; it does not generate electricity, but instead acts as a hub that aggregates loads and generators, controlling dispatch and demand-side management in a decentralized fashion. Smart Grids can capitalize on advances in communications technology, utilizing internets in particular to synchronize operations, develop demand-side control at the micro- level, control generation response to strain on the centralized grid system, and enable new opportunities for novel ancillary services. These operations could be performed through a 'virtual utility' or 'virtual power plant', "a multi-fuel, multi-location and multi-owned power station" that can supply energy as necessary with the ability to change both generation and demand rapidly to correct system imbalances. [37]

The European Commission's introduction to DG highlights that the virtual power plant "is not itself a new technology but a method of organising decentralised generation and storage in a way that maximises the value of the generated electricity to the utility." [38], [39] While the technical and economic feasibility of virtual power plants depends largely on particular logistical and situational circumstances, the exploration of new options for maximizing the efficiency and capacity of DG resources will require incentives for distribution and transmission innovation.

Although incentivizing innovation within the transmission and distribution system is important in providing DG with access to the grid, establishing a fair market for renewable DG is perhaps the most critical factor in determining its success. There are several different ways to level the playing field for renewable DG that competes with heavily subsidized centralized, non-renewable generation: tax incentives, the establishment of a market for emissions certificates, and a number of other policy toolkits are available to regulators that can help to put renewable DG on fair footing with other sources of energy. Historically, however, the most successful policy mechanism in the promotion of distributed renewable energy has proven to be the Advanced Renewable Tariff (ART), known in Ontario as the Standard Offer Contract, and in many parts of Europe as the electricity feed-in law.

ARTs guarantee access to the grid for renewable generators, and offer a standardized price for the electricity they generate. In Europe, this policy mechanism has lead to more renewable capacity than any other policy. Germany, an early adopter of feed-in laws, is now one of the foremost producers of renewable energy, with well over 18 500 MW of installed capacity in wind generation alone, and approaching 1 000 MW of solar photovoltaic capacity. [40], [41] For both technologies, a considerable segment of new installations in Germany are under 10 MW. ARTs are also an equitable method in determining who will own what generation capacity, where it will be sited, and how it's controlled. Structured properly, ARTs can promote renewable DG while boosting community economic development.

ARTs have been utilized in 41 jurisdictions, including Germany, France, Spain, and the Netherlands, along with several other countries, and are being implemented or considered in Ontario, California, Italy, China, India and a number of other regions. In Europe, the ARTs used in Denmark, Germany, and Spain has helped to propel them to the forefront of renewable generation. The success of an ART is contingent on many factors. The policy must specify a contract length that is sufficient to provide a reasonable amount of stability and certainty to investors, often as long as 20 to 25 years. Prices must also be properly determined to allow smaller investors to invest with confidence without undue risk. Additionally, prices offered must be sufficient to encourage new investment in renewable energy, while remaining in line with the benefits that renewable DG provides. Sites with moderate resources must also be provided a sufficient price to ensure some profitability, a consideration of particular importance to DG. Yield-based pricing has worked particularly well in the case of Germany. [42] Finally, for ARTs to be approached by potential generators, both the contracts and the interconnection process must be streamlined[43] to ensure a minimum of difficulty in project development.[44]

With many jurisdictions now exploring and implementing DG options worldwide, Canada has several models from which an effective approach to the deployment of DG can by synthesized.

7. Recommendations

1. Recommendations for federal and provincial collaborations:
Facilitate the rapid deployment of distributed generation:

1.1 Provide access to development capital and adequate financing through innovative loan, grant and tax-based incentive programs: An integrated financial program, including zero- or low-interest loans,

grants and progressive policy mechanisms will enable the participation of individuals and communities in DG, improve loan repayment and project success rates, and tap into community capital for energy infrastructure.

1.2 Implement effective renewable energy policy mechanisms, with particular consideration given to Advanced Renewable Tariffs (ARTs): In conjunction with the provision of start-up capital and adequate financing, provincial and territorial governments should adopt policy approaches that promote the growth of renewable DG. Advanced Renewable Tariffs (ARTs), such as the recently-announced Standard Offer Contract program in Ontario, are a proven mechanism of support for renewable DG. **The federal government has an opportunity to ensure that ARTs will work in jurisdictions across Canada by uniting the policy efforts of the provinces and territories,** while maintaining the WPPI as a complimentary support to ARTs across Canada. While ARTs can take different forms, their basic function is to provide a fixed price per kilowatt-hour of generation to community-scale generators of renewable energy for an extended contract term, typically from 15 to 20 years. These policies provide the stability To be effective drivers of DG, ART policies must have a few critical components. They must:

- streamline interconnection to the grid, allowing small-scale generators of renewable energy to sell their energy ;
- offer a reasonable fixed price to producers of renewable energy, preferably through a tiered pricing model based on site-specific resources to encourage the broad distribution of renewable generation capacity rather than concentrations of generation far from electricity loads;
- incorporate fair compensation for transmission loss reduction and avoided transmission costs in the contract pricing models;
- offer that fixed price over a sufficient contract duration to provide a degree of security and certainty for investors, banks, and other financiers, which enables the rapid growth of renewable electricity generation;
- allow for broad participation in electricity generation. Federal support for such policies will help harmonize regional approaches and speed implementation of progressive policy;

1.3 Invest in public and technical education on renewable energy, distributed generation and new technologies: Education programs give individuals and groups the confidence to invest in distributed renewable energy projects. Federal and provincial governments need to *provide funds for universities, colleges and civil society actors to implement and deploy DG* and educate the public, tradespeople and professionals. Provinces and territories must develop and implement practical strategies to train and educate a skilled technician base capable of supporting integrated power systems and distributed technologies through post-secondary and certificate-based training programs, utilizing existing programs like the Association of Canadian Community Colleges renewable energy program. The coordination of broad deployment and support strategies for DG could be carried out through a national renewable energy secretariat, as recommended by the Canadian Renewable Energy Association.

1.4 Provide technical support, educational resources and secondment opportunities for utilities and local distribution companies:
Historically, one of the most immediate barriers to DG in North America has been unfamiliarity with the technology involved or an unwillingness to participate in novel procedures and project types on the part of utilities and local distribution companies. This typically stems from a lack of resources that LDCs are able to dedicate to a particular type of generation, like DG. Because of the prevalence of centralized generation, not all LDCs have staff capable of dealing with DG in an equitable and informed manner, and so it may be necessary to build that capacity within LDCs. Through training programs and through the establishment of liaisons or technical assistance teams that can ensure the least-hassle solutions to DG-related issues are adopted and implemented widely, cutting down on the number of disputes between LDCs and potential generators. The implementation of recommendation 3.3 in this paper would also further the goal of involving LDCs considerably. Federal and

provincial governments need to facilitate staff secondments and professional development placements to increase local capacity.

2. Recommended actions for the federal government:
To continue to develop a distributed grid that makes sense for the future:

2.1 Implement a collaborative multi-stakeholder consortium to research and implement best practices for a secure, sustainable distributed grid: In the U.S., the GridWise Alliance is helping to form "an electric system that will employ new distributed 'plug and play' technologies using advanced telecommunications and information and control approaches" to create an internet-like power grid. In Europe, the SmartGrids Technology Platform[45] is coordinating the development of a grid that is flexible, accessible, reliable and economical. The federal government should coordinate a similar approach to reap the benefits of DG and to maintain Canada's competitiveness in the global market. The federal government should develop a new initiative, involving Natural Resources Canada, Industry Canada, Human Resources and Social Development Canada and provincial bodies to guide this process. [46]

2.2 Invest in innovative DG technologies: Maximizing the benefits of renewable energy and DG will require aggressive deployment and commercialization of existing energy storage technologies, power electronics and other mature technologies, such as the virtual power plant concept. By encouraging further growth in these industries, Canadian industries can capitalize on the global transition to a new era of DG.

3. Recommended actions for provincial and territorial governments
To facilitate the rapid deployment of distributed generation:

3.1 Remove barriers to grid interconnection for small-scale renewable generators: Many interconnection requirements designed for large, centralized generators are unnecessary for smaller generators. Developing safe and reasonable standards for interconnection will maximize the contributions of renewable energy and ensure the protection of grid operators and maintenance personnel. Many safety and system stability concerns surrounding DG relate to "islanding", a phenomenon that occurs when a section of a distribution system becomes electrically isolated from the rest of the system, while still being energized by DG that is connected to that section of the distribution system. [47] Using current anti-islanding methods could prove costly as the penetration of DG increases[48]. New grid and distribution system management techniques must be assessed and adopted where appropriate to facilitate the rapid growth of DG. The implementation of a SmartGrid style plan would include the establishment of microgrids, more isolated, localized distribution systems that present a potential solution to the islanding problem and can also improve localized system reliability. [49]

Many of these solutions, though achievable, challenge the status quo and will require the cooperation of local distribution companies, also known as LDCs. In order to make the prospect of DG favourable to LDCs, it is imperative that LDC / utility revenues do not remain a direct function of the number of kilowatt-hours of electricity they sell. Instead, analyses of utility effectiveness that take into account other metrics focusing on end-user satisfaction and benefits should be practiced to determine the level of service being provided by an LDC / utility. In this way, the participation of LDCs in a sustainable energy future with a strong commitment to renewable DG can be assured through the provision of meaningful incentives that will lead to a willingness to participate in and recognize the benefits of DG on the part of LDCs.

3.2 Standby Charges: In many provinces, LDCs can charge standby fees to load displacing generation. For small generators of electricity, such fees are administratively expensive and largely unwarranted. Small-scale generators should be exempted from standby charges wherever possible.

3.3 Streamline planning and permitting processes through the development of standards for embedded generation technologies in regional building codes, reasonable electrical standards, and streamlined siting procedures. Building codes should specify considerations that allow for future embedded solar generation where possible. For homeowners wishing to install embedded generation, permitting should be made as

simple as possible. In the UK, new proposals have been tabled to limit planning restrictions on embedded and microgeneration, allowing homeowners to install solar panels and small-scale wind projects without having to endure a lengthy permitting process. [50]

3.4 Provide incentives for generators and utilities to move away from the traditional motivation of selling more electricity: The dissociation of revenue streams away from the total kilowatt hours of electricity sold by utilities is critical to the development of an energy efficient culture focused on conservation. In particular, "utilities should be rewarded not for selling more kWh, but for helping customers get desired end-use services," [51] an approach that has met with success in Oregon, [52] and one that is practicable in a Canadian context. Provincial governments, with the support of federal resources, can adopt a performance-based approach when evaluating the effectiveness of utilities and when considering who to provide incentives. By providing incentives or regulation that focuses utilities on providing the best possible service to the end customer rather than privileging those who sell the most electricity, significant demand reductions can be achieved as distribution companies and / or utilities bring their resources to bear on demand-side management issues, including conservation and energy efficiency.

4. Recommended actions for municipal and local governments

Advance local solutions to multiply the benefits of DG

4.1 Develop community energy plans and land-use policies that support distributed generation: Municipalities must develop policies and strategies that encourage the siting of DG technologies [53] to provide opportunities for improved energy security and to benefit from the revenue streams provided by distributed technologies. Rapidly growing areas, such as Ontario's York Region, must plan ahead to take advantage of the shift toward distributed and embedded generation.

4.2 Promote innovative, local solutions to growing energy demand: Local governments should look to local solutions for growing energy demand by engaging community members through partnerships in community / municipally-owned renewables.

Inspire and educate at the community level

4.3 Lead by example: Local governments can partner with community groups to create demonstration projects that educate community members and encourage the deployment of DG technologies [54] outside of the demonstration project.

4.4 Promote awareness and an understanding of energy issues: Public awareness campaigns to reduce electricity use and encourage smart energy choices are a key component of a DG vision, and can make local economies more attractive to businesses. Establishing and maintaining municipal or regional commitments to the mitigation of greenhouse gas emissions allows for an even greater role for DG in the near term than might otherwise develop.

Additional resources

SmartGrids Technology Platform: Vision and Strategy for Europe's Electricity Networks for the Future
http://ec.europa.eu/research/energy/pdf/smartgrids_en.pdf

GridWise Alliance
http://www.gridwise.org/
"A consortium of public and private stakeholders who have joined together in a collaborative effort to provide real-world technology solutions to support the U.S. Department of Energy's vision of a transformed national electric system. An electric system that will employ new distributed 'plug and play' technologies using advanced telecommunications, information and control approaches to create a society of devices that functions as an integrated transactive system."

Small is Profitable
http://www.smallisprofitable.org/
"Small is Profitable describes 207 ways in which the size of "electrical resources"-devices that make, save, or store electricity - affects their economic value. It finds that properly considering the economic benefits of 'distributed' (decentralized) electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation, and service quality, and by avoiding societal costs. Small Is Profitable introduces engineering and financial practitioners, business managers and strategists, public policymakers, designers, and interested citizens to the new value opportunities presented by considering these economic benefits. It also provides a basic introduction to key concepts from such disciplines as electrical engineering, power system planning, and financial economics."

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Section 5
BC Transmission Inquiry

Comments on Scenarios
to BCTC

by: ESVI, OEIA, ITO and ROMS BC

By: Ludo Bertsch, Horizon Technologies Inc.
[redacted]
Date: Aug 12, 2009
For: ESVI, OEIA, ITO and ROMS BC

On August 5, 2009, BCTC held a Scenario workshop for the Long Term Electricity Transmission Inquiry. Participants were given the opportunity to provide written comments by August 12, 2009 for BCTC's consideration in its September 18 filings.

The following document contains the written comments on behalf of Energy Solutions for Vancouver Island Society (ESVI), Okanagan Environmental Industry Alliance (OEIA), IslandTransformations.Org (ITO) and Rental Owners and Managers Society of BC (ROMS BC).

In order to reduce the size of the attachments, web-site links are provided for the larger documents – we would be pleased to send any document files that might be required, or a complete package of attachments if it is helpful.

Yours truly,
Ludo Bertsch, P. Eng
Horizon Technologies Inc.
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[redacted]

Representing: ESVI, OEIA, ITO and ROMS BC

P.S. Please note our Errata on the next page noting a few section number corrections.

Errata (from Version .008)

Section 2.2.1: Should read: "*Beyond the suggestion for more DSM as noted in Section **2.1.3**. . .*"
Section 4: A few sections have been renumbered within this section.
Footnote 219: Should read: "*See Section **2.2.1***"
Footnote 228: Should read: "*See Section **2.2.1***"
Footnote 229: Should read: "*See Section **2.2.2***"

Summary

The following is a brief summary of the sections of our submission – for specific and full recommendations, please refer to the text within the document.

Section 1:

We suggest that the "*Non-Wires*" Initial Scenario proposed by BCTC should be renamed "*Integrated Non-Wires*" and should be defined as:

> Energy policy in BC focuses on encouraging integrated non-wire regional solutions (e.g. DSM, strategic IPP generation placement, conservation rates) and development of local and distributed generation to limit transmission development.

Section 2.1:

In response to restrictions placed on the use of the LTAP in the Transmission Inquiry, we suggest clarification. We also suggest higher levels of DSM in the "*Current Practice*" due to the LTAP Decision.

Section 2.2.1:

We suggest an Initial Scenario should include higher levels of DSM.

Section 2.2.2:

We suggest an Initial Scenario should include Electric Vehicles.

Section 3:

We suggest clarifications on building up the Scenarios, including the proposed definitions of the Drivers for Scenarios (e.g. economy, technology, policy decisions and environmental developments).

Section 4.1:

We suggest an Initial Scenario should accommodate a wider range of climate and climate-related events.

Section 4.2

We suggest an Initial Scenario should have more aggressive pricing approach for the future price of carbon.

Section 5

We suggest an Initial Scenario should incorporate Feed-In Tariffs and Distributed Generation.

Section 6

We suggest an Initial Scenario should include Solar technology.

Section 7

We suggest an Initial Scenario should include Ocean technology.

Section 8

We suggest a new Initial Scenario, “Expanded Integrated Non-Wires”. Each driver is discussed in detail: economy, technology, policy decisions, and environmental developments.

1.0 Non Wires Initial Scenario:

1.1 Non-Wires

1.1.1 "Non-Wires" in BCTC Scenario Workshop Presentation

The BCUC Scoping Document[1] describes a significant feature of scenarios:

> "*Agreement or Panel direction on a manageable number of demand scenarios, which are* ***meaningfully different*** *from each other, is vital to the Panel delivering useful determinations*"[2]. [***emphasis added***]

In the "*Development of Initial Scenarios*" section[3] of the BCTC Scenario workshop, seven potential scenarios were presented[4].

A "*current practice*" scenario (e.g. "business as usual") was presented as:

> "*The world looks similar in 2040 as it does today; no major changes in demand or resource availability*"[5]

Five other scenarios (#2 to #6) were presented using the adjectives: "*low*", "*high*", "*moderate*" or "*aggressive*"[6]. The seventh scenario, "*non-wires*", is presented without an adjective. The implication here seems to be that scenarios #2 to #6 point to the main attributes which are significantly different (lower, higher etc) from the "*current practice*", whereas the characteristics of scenario #7 are implied within the name "*non-wires*" and therefore implied to be significantly different than "*current practice*".

The "*non-wires*" scenario in the BCTC scenario workshop presentation by Dr. Ren Orans is described as:

> "*North America agrees to cut emissions by half relative to today; restrictions on the development of new, large power plants and transmission require a focus on development of local and distributed generation*"[7]

1.1.2 "Non-Wires" in the Electric Utility Industry

In 2001, the Bonneville Power Administration was faced with $775 million of transmission infrastructure improvements after having "*added virtually no circuit*

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[1] BCUC Order G-86-09, Appendix A, Attachment A, Page 3 of 7
[2] BCUC Order G-86-09, Appendix A, Attachment A, Page 3 of 7
[3] BCTC Scenario Workshop presentation, Aug 5, 2009, slides 20 to 27
[4] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 22
[5] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 23
[6] "***Low*** *economic growth*", "***High*** *economic growth*", "***High*** *renewable targets in USA*", "***Moderate*** *GHG reductions*", "***Aggressive*** *GHG reductions*"
[7] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 24

miles in the transmission system since the late 1980's"[8]. "*Before proceeding with the construction of transmission projects, BPA wants to ensure that there is a clear and compelling demonstration of project need and that it is providing the most cost-effective solution to the region's transmission problems from an engineering, economic and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions can include pricing strategies, demand reducing strategies, and strategic placement of generators.*"[9]

BPA recognizes that "*In many respects these nonwire activities have been outside the TBL's [Transmission Business Line] purview and TBL has had to be passive with respect to them*"[10].

In reviewing the existing Transmission Business Line (TBL) planning process[11], BPA recognized that "*it identifies transmission needs on a schedule that is too late for implementation of nonwires alternatives*"[12]. "*A longer term, system-wide planning process is needed as a supplement to the existing process*" [13].

As noted in an E3 report (authored in part by Dr. Ren Orans) it states that problems with traditional planning is that there is "*insufficient time to consider non-wires alternatives*"[14] and "*insufficient time to engage other stakeholders*"[15].

BPA suggests that a multiple screening process be implemented which includes "*non-wires solutions*"[16] which makes the process "*more proactive and expansive*"[17].

BPA noted categories of potential transmission and nonwire activities to include[18] transmission expansion, merchant transmission, wholesale and retail pricing, demand management (including energy efficiency programs and load shifting programs)), and strategically placed generation plants.

The process would add two new functions, a 10 year system-wide report and a two-part screening process[19], plus provide opportunities for stakeholder

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[8] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[9] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[10] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[11] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8, Figure 1
[12] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8
[13] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8
[14] Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 4
[15] Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 4
[16] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 11, Figure 2 and Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 8
[17] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 7
[18] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 9
[19] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 7

involvement in the form of two workshops[20] well in advance of the project need.

The implementation of the new process would mean that "*every potential transmission project would appear on the market participants' radar screen at least ten years before the project need date*"[21].

"*BPA cites two past successful demand response projects that justify its current efforts at finding additional non-wires solutions. Traditional conservation measures lowered peak loads on Orcas Island for several years while an underwater cable was replaced. The Puget Reinforcement Project used conservation programs to help[~~ed~~] avoid voltage collapse in the Puget Sound area and delayed construction of additional transmission lines crossing the Cascade mountains for ten years.*"[22]

"*Subsequently, BPA formed a Non-Wires Solutions Round Table to obtain opinions from diverse set of stakeholders within the region*".[23] It was recommended that a expected load project on the Olympic Peninsula be taken through the non-wires screening process[24], including avoided cost analysis.

An example of benefit/cost ratios and assumptions for non-wire alternatives are shown in the Appendix 1[25], which was implemented in BC by the E3 group[26].

In the "*Worldwide Survey of Network-driven Demand-side Management Projects*"[27], the Olympic Peninsula project is listed as one of eight "*Integrated DSM Projects*", and the only one listed in North America. It is described as "*several pilot projects to determine whether it is possible to use non-wire solutions to defer a transmission line construction project*"[28].

In Vermont, "*prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate*

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[20] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 4

[21] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 10

[22] www.ferc.gov/legal/staff-reports/demand-response.pdf, Federal Energy Regulatory Commission, "*Assessment of Demand Response & Advanced Metering*", August 2006, Page 106

[23] www.ferc.gov/legal/staff-reports/demand-response.pdf, Federal Energy Regulatory Commission, "*Assessment of Demand Response & Advanced Metering*", August 2006, Page 106 - 107

[24] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Pages 5, 17 to 23

[25] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Appendix 1

[26] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 10, Footnote 6

[27] www.google.com/search?q=Worldwide+Survey+of+Network-driven+Demand-side+Management+Projects&rls=com.microsoft:en-US:&ie=UTF-8&oe=UTF-8&sourceid=ie7&rlz=1I7ADBR, International Energy Agency "*Worldwide Survey of Network-driven Demand-side Management Projects*"

[28] www.google.com/search?q=Worldwide+Survey+of+Network-driven+Demand-side+Management+Projects&rls=com.microsoft:en-US:&ie=UTF-8&oe=UTF-8&sourceid=ie7&rlz=1I7ADBR, International Energy Agency "*Worldwide Survey of Network-driven Demand-side Management Projects*", Page 11 and Page 95 to 103

nontransmission alternatives."[29]

We suggest that the use of "*Non-Wires*" in this Inquiry is exemplified by the information referenced above.

1.1.3 Current "Non-Wires" Practice for BCTC

This section is intended to describe the current practice for BCTC regarding "*Non-Wires*".

In the F2006 to F2015 Transmission System Capital Plan, BCTC noted from the previous Capital Plan that "*the Commission Panel also noted that, 'DSM solutions to transmission issues may be in the public interest and the role of BC Hydro and BCTC regarding the DSM solutions to transmission issues remains an outstanding issue'. BCTC has considered this issue further as a result of the Commission's statement. BCTC has indicated that it is prepared to consider DSM opportunities as 'bridging' resources while longer-term solutions are being put in place. BCTC also contracts for 'non-wires' solutions as part of various Remedial Action Schemes. BCTC is in the process of reassessing its role in evaluating and contracting to avoid or delay 'wires' solutions in light of the Commission's comments.*"[30]

In the decision for the capital plan "*the Commission Panel therefore directs BCTC, if it has not already done so, to initiate discussions with customers (including BC Hydro) on potential customer-provided solutions to transmission constraints, and to report to the Commission on the outcome those discussion in its next capital plan. Without limiting the scope of the discussions, the Commission Panel expects BCTC will examine the following in conjunction with BC Hydro:*

- *options for general (i.e. system- or area-wide) demand reductions, to the extent they are not already covered by existing DSM initiatives such as PowerSmart;*
- *options for location- or area-specific demand reductions, either planned or in response to system events (e.g., by arming customer-specific remedial action schemes);*
- *demand reduction timing requirements (e.g. all hours, peak months or hours, or only when armed);*
- *mechanisms for compensating customers, such as reduced rates, direct payments through commercial contracts, or investment deferral credits;*
- *options for customer-supplied transmission services, such as reactive power or reliability must-run generation.*

[29] Appendix C, The Vermont Statues Online, Title 30, Public Service, Chapter 5, Section 281c, d(2), Page 2

[30] BCTC F2006 to F2015 Transmission System Capital Plan, March 23, 2005, Page 4

The Commission Panel further notes that, as the entity responsible for developing solutions to transmission constraints, BCTC is in the best position to identify the extent to which customer- or third-party-provided solutions could defer or eliminate the need for Growth Capital investments. Without pre-judging whether BCTC or BC Hydro (or both) should ultimately contract for non-wires solutions, the Commission Panel expects that BCTC will identify non-wires solutions in future studies and capital plan applications."[31]

BCTC reported on non-wires in its OATT Rate Design Report on December 20, 2006[32].

In the F2008-F2017 Capital Plan, BCTC reported that many of its substations and transformers that "*non-wires options which were deemed not feasible in the absence of new generation or IPP development prospects in the area*"[33].

In the F2009-F2018 Capital Plan, BCTC reported in relation to various projects: "*the magnitude of the likely achievable DSM effects would be insufficient to address the need*", "*this is a significant reduction in use and unlikely to be achieved from residential and commercial DSM programs*", "*there is insufficient time available to implement either a DSM project or to construct generation and meet the in-service date . . .*" and "*there isn't sufficient load . . . to implement an effective DSM project*"[34].

In the F2010/F2011 Capital Plan, added a new section, "*Projects with Non-Wires Solutions"*[35]. "*BCTC examines whether or not non-wires alternatives exist in the planning analysis that leads to the selection of preferred alternatives. None of the projects in this TSCP, for which BCTC is seeking approval to install or expand facilities, have practical non wires alternatives. Demand side management targets are already built in to the load forecast that drives these projects and there are no generation resources in the vicinity of the projects that could offset the growing load.*" [36]

"*As outlined in the F2009 TSCP, non wires alternatives such as the integration of generation interconnection in the . . . valley are being considered. BCTC is examining the dependable capacity of the run of river projects that exist and/or are being proposed, and the possibility of higher dependable capacity thermal*

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[31] BCUC BCTC F2006 to F2015 Transmission System Capital Plan Decision, Sep 23, 2005, Pages 19 to 20

[32] BCTC OATT Compliance Filing – Rate Design Report, Dec 20, 2006, Appendix B

[33] BCTC F2008 to F2017 Transmission System Capital Plan, Dec 21, 2006

[34] BCTC F2009 to F2018 Transmission System Capital Plan, Dec 21, 2007

[35] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124 to 5-125

[36] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124

generation projects in this region. To maintain the ability to supply the . . . area until a suitable solution can be put in place, BCTC and BC Hydro are engaged in discussions with a customer in the . . . area to explore load curtailment measures." [37]

"*. . . significant wind resources exist in the . . . area that may contribute to the solution for reinforcing this region. While some transmission reinforcement may be required to integrate this wind, the same reinforcements may be used to supply load, and some of the capacity from the wind generation may serve to offset some of the transmission capacity that would otherwise have been required to meet incremental load.*" [38]

A recent specific project can be used as an example to help understand how BCTC currently handles the "*Non-Wires*" approach. In the December 10, 2008 BCUC decision on the Central Vancouver Island Transmission Project a series of "*non-wire*" alternatives were discussed[39]: DSM, load generation, remedial action schemes, and curtailment.

BCTC notes that "*. . . any new generation project that may be announced would not likely be in service by October 2010, to meet the required ISD for the proposed solution to the capacity constraints in CVI . . .*" [40]

"*BCTC does not address curtailment in its Application. However, BCTC addressed the Customer Capacity Curtailment Contracts entered into by BC Hydro and certain of its customers . . .* "[41].

BCTC's approach for Non-Wires is being recognized in the utility industry – for example, a report from New Zealand lists BCTC as one four approaches world-wide: "*BCTC has recently (2006) undertaken to evaluate non-wires transmission alternatives where such alternatives have the potential to avoid or delay wires solutions.* "[42]

However, the report summarized the success, "*BCTC recently assessed opportunities for non-wire transmission alternatives – but failed to identify any.*" [43]

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[37] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124
[38] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-125
[39] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008
[40] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008, Page 19
[41] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008, Page 20
[42] Appendix D, Transpower New Zealand, Selected pages of "*Grid Support Contracts*", Nov 2008, Page 16
[43] Appendix D, Transpower New Zealand, Selected Pages of "*Grid Support Contracts*", Nov 2008, Page 16

Although BCTC is using the "*Non-Wires*" approach, we suggest that the current practice of BCTC is of an early form, more of a "*passive*" approach – no detailed analysis are done, there is often not adequate notice to consider other approaches, and there are typically no formal meetings or workshops to draw out other solutions from stakeholders before application.

1.1.4 Our Assessment of "Non-Wires" for the Transmission Inquiry

We suggest that the title "*Non-Wires*" on its own for the scenario in the Transmission Inquiry is not satisfactory. As evidence in section 1.1.3, BCTC is already committed to and using a "*Non-Wires*" approach. As stated previously, one of the goals of the Transmission Inquiry is to ensure that the scenarios are "*meaningfully different*" from each other. A scenario of "*Non-Wire*s" would not be "*meaningfully different*" than the "*current practice*" and therefore would not be appropriate.

The fact that BCTC is already moving in this direction is helpful. As shown in section 1.1.3, from the introduction of the "*Non-Wires*" approach in the F2006 Capital Plan, BCTC has progressively endorsed and placed greater focus on this area.

However, for the Transmission Inquiry, to differentiate from the current practice and test further analysis through non-wire approaches, it is suggested that the scenario be renamed to "*Integrated Non-Wires*". It is suggest that this "*Integrated Non-Wires*" scenario move to the more advanced levels of the "*Non-Wires*" approach in the future than as with "business as usual" - for example, adding new concepts from the Olympia Peninsula project, and similar projects.

A presentation on the International Energy Agency DSM Program highlights "*a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.*"[44]

- Forecasting future electricity demand[45]
- Communicating information about network constraints[46]
- Developing options for relieving network constraints[47]
- Establishing policy and regulatory regimes for network planning[48]

This scenario assumes that BC would endorse an integrated non-wire policy environment and would address the key areas as listed above, plus in "*Non-*

[44] Appendix E, International Energy Agency, IEA DSM Programme, Page 25
[45] Appendix E, International Energy Agency, IEA DSM Programme, Page 27
[46] Appendix E, International Energy Agency, IEA DSM Programme, Page 28
[47] Appendix E, International Energy Agency, IEA DSM Programme, Page 29
[48] Appendix E, International Energy Agency, IEA DSM Programme, Page 30

Wire" processes described in section 1.1.2. For example, it would be assumed that the recommended process as suggested for BPA[49] would be implemented - this includes a 10 year-ahead planning report, workshops, analysis and screening processes.

A key principle is to ensure the process is integrated between transmission, generation and demand. This allows non-wire solutions, such as DSM or strategic local renewable generation, to have a reasonable lead-time in order to be fairly considered and encouraged over potential transmission infrastructure enhancements.

This approach would also allow BCTC to support the DSM, conservation, energy efficiency goals in the 2007 Energy Plan at the same time ensuring that the overall lowest cost solutions are found for the overall BC electrical system – e.g. BC Hydro, Fortis BC and BCTC combined.

It is suggested the wording for this scenario[50] state:

Integrated Non-Wires

Energy policy in BC focuses on encouraging integrated non-wire regional solutions (e.g. DSM, strategic IPP generation placement, conservation rates) and development of local and distributed generation to limit transmission development as illustrated in ESVI et al's comment submission.

2.0 BC Hydro's 2008 LTAP, Demand & DSM:

2.1 BC Hydro's 2008 LTAP

2.1.1 Transmission Inquiry treatment of 2008 LTAP

The Terms of Reference of the Transmission Inquiry issued by the Government of BC notes that the Commission must have regard for "*the load-serving utilities' long-term resource plans filed under section 44.1 of the Act, including their most recently filed and relevant contingency resource plans as accepted by the Commission*"[51].

The Terms of Reference also note: "*In addition to any other evidence and submissions relevant to the inquiry that the load-serving utilities may wish to provide, if not adequately addressed in their most recently approved long-term*

[49] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities"
[50] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 24
[51] Government of BC, Terms of Reference, Dec 17, 2008, Page 3 of 7, section 7(a)

resource plans, the Commission must allow the load-serving utilities to provide evidence and submissions regarding their electrical energy and capacity requirements for the Determination Period . . ."[52].

In its Decision on Scope, the Panel Inquiry clarifies that "*BC Hydro's and FortisBC's long term resource plans, including their recently filed and relevant contingency resource plans as accepted by the Commission are in scope*"[53].

The Inquiry Panel in its Scoping Decision states: "*In addition, scenarios may need to be developed to reflect future outcomes that were not adequately addressed in the [2008] LTAP.*"[54]

In its Scoping Decision it is also stated in regards to items "*Not in Scope*": "*The Panel interprets the direction provided in the Terms of Reference with regard to the utilities' most recently approved long-term resource plans to mean that the Inquiry is not intended to be a forum for revisiting BC Hydro's June 2008 LTAP after the Commission LTAP Panel has issued its Decision on it. Thus the Panel does not consider that revisiting any load forecast or DSM forecast methodology that has been approved by the Commission in its forthcoming decision on BC Hydro's LTAP to be in scope.*"[55]

2.1.2 Outcome of BC Hydro's 2008 LTAP

On July 27, 2009, BCUC issued its decision on BC Hydro's 2008 LTAP[56].

One of the BCUC Directives states: "*The Commission Panel has concluded that BC Hydro has not met the statutory burden it acknowledged the Act requires. Accordingly, the Commission Panel finds that it is unable to determine the DSM Plan as proposed by BC Hydro complies with section 44.1 of the Act.*"[57]

Some of the Commission's Determinations in support of this Directive include:

> "*The Commission Panel does not accept BC Hydro's assertion that by meeting more than its load growth with DSM it would impose a cost on its ratepayers, since the portfolio analysis prepared by BC Hydro in Figure 5-14 of Exhibit B-1 only showed that this might happen in extremely remote circumstances.*"[58]
>
> "*As noted in Section 1.2 of this Decision, BC Hydro provided its interpretation of*

[52] Government of BC, Terms of Reference, Dec 17, 2008, Page 6 of 7, section 8(a)
[53] Exhibit A-18, Appendix A, Attachment A, Page 3 of 7
[54] Exhibit A-18, Appendix A, Attachment A, Page 3 of 7
[55] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[56] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008
[57] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 181, Directive 12
[58] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 84

the relevant framework as" 'Pursuant to subsection 44.1(2)(b), [BC Hydro] must pursue all cost-effective DSM prior to pursuing any supply-side options, [and] pursuant to subsection 44.1(2)(f), BC Hydro must prove why it cannot fill its entire load/resource gap with DSM only.'"[59]

Another BCUC Directives states: "*Inasmuch as BC Hydro has effectively chosen to truncate its DSM programs in F2020 by letting the impact of those programs progressively decay, the Commission Panel find that BC Hydro's DSM Plan is deficient.*"[60]

In support of this Directive, BCUC states "*The Commission Panel agrees with CEC and ESVI that BC Hydro's 20-year plan does not reflect the fact that there will be more cost-effective DSM available than is planned for in Adjusted Option A.*"[61]

Another BCUC Directives states: "*The Commission Panel believes that parts of the LTAP it has rejected represent a level of individual and collective materiality that removes the underpinnings of the entire 2008 LTAP. Accordingly the Commission Panel finds that BC Hydro's LTAP is not in the public interest and rejects it.*"[62]

In support of this Directive, BCUC states "*Among other things, the Commission Panel has rejected or found deficient the following parts of the 2008 LTAP: . . . DSM Plan – BC Hydro allowed its programs to progressively decay over the relevant period . . .'*[63]

2.1.3 Our Assessment of 2008 LTAP DSM for the Transmission Inquiry

Given the uncertainty around whether to use BC Hydro's rejected 2008 LTAP or accepted 2006 IEP/LTAP for the Transmission Inquiry, we suggest that it is more appropriate to use the 2008 LTAP with appropriate compensation, as the 2008 LTAP reflects the understanding of the 2007 BC Energy Plan and the 2006 IEP/LTAP does not reflect the 2007 BC Energy Plan.

We suggest that because the DSM plan of BC Hydro's LTAP was found "*deficient*" and does not comply with the Act, plus that the decay of the DSM plan was noted as a reason for rejecting of the entire LTAP, that the calculations for the BC Hydro domestic electricity demand should be lowered to compensate for the increased DSM before incorporating it into the Transmission Inquiry and before extending the

[59] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 85
[60] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 181, Directive 13
[61] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 86
[62] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 182, Directive 22
[63] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 131

study period[64]. It is suggested that the calculations and assumptions be clearly shown.

As noted above, the Panel discussed items not in scope: "*the Inquiry is not intended to be a forum for* ***revisiting*** *BC Hydro's June 2008 LTAP after the Commission LTAP Panel has issued its Decision on it.*"[65] [***emphasis added***] This statement revolves around the meaning of the word "*revisit*". We suggest that the appropriate use of the word "*revisit*" is contained in the YourDictionary.com, whose definition is: "*to reconsider or reevaluate*"[66]

We suggest that these restrictions of using the LTAP in Transmission Inquiry were developed to cover the case where the intent is to reconsider decisions made in the LTAP, in order to attempt to change such decisions. We suggest that these restrictions were not developed to cover other purposes of using the LTAP, including looking at the LTAP (and its Decision) in order to understand what the ramifications might be nor how the Decisions of the LTAP might affect the market.

2.2 Further Comments about Demand & DSM

2.2.1 Higher levels of DSM

Beyond the suggestion for more DSM as noted in Section 2.1.3 above[67] for the "*current practice*" "correction", we suggest that it would be appropriate to have an Initial Scenario that includes significantly more DSM than the "*current practice*" using techniques (if they are not already considered in the "current practices") such as rates linked to energy efficiency of homes and lower greenhouse house emissions, other advanced conservation (e.g. dividend) rates, advanced communicating appliances, smart meters, advanced demand responses including critical peak pricing, time of use rates, community distributed generation, load shedding, curtailment, rental/landlord DSM etc.

It is suggested the following documents be reviewed for potential new DSM techniques and appropriate methods and suggest it be included in this Initial Scenario: BC Hydro's latest BC Hydro's Conservation Potential Review, the Vancouver Island study by Rocky Mountain Institute[68], and notes/minutes from BC Hydro's Rates Working Group, notes/minutes from BC Hydro's Energy Conservation & Efficiency Advisory Committee and notes/minutes from

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[64] "*Because the Inquiry study period is longer than the LTAP period, the LTAP forecasts will need to be extended.*": Exhibit A-18, Appendix A, Attachment A, Page 3 of 7

[65] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

[66] www.yourdictionary.com/revisit

[67] that "*the BC Hydro domestic electricity demand should be lowered to compensate for the increased DSM before incorporating into the Transmission Inquiry and before extending the study period*"

[68] Appendix R, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003,

FortisBC's DSM Advisory Committee.

2.2.2 Electric Vehicles

Electric vehicles treatment in the Transmission Inquiry

The BCUC scoping document states: "*The Independent Power Producers Association of British Columbia (" IPPBC") submitted that the following matters should be within scope: . . . technologies that can be used to store electricity such as batteries in hybrid electric vehicles. . .* ***The Panel agrees that all of these issues are in scope.***"[69]

> "*CPC also encouraged the Panel to look at how broad deployment of electric plug-in vehicles within the study period would affect transmission requirements and operations.* ***This is a scenario that has been suggested by several participants and the Panel considers such a scenario to be within the scope of the Inquiry.***"[70]
>
> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference. . . . Investigation of whether or not electricity storage options such as batteries in hybrid electric vehicles . . . are available as a means of meeting capacity requirements and whether it is cost competitive with other alternatives;*"[71]
>
> In scope topics for Assessment of Domestic Electric Demand include: "*New technologies such as electric vehicles . . . may increase demand . . .*"[72]

Recent electric vehicles activity

An August 11, 2009 news release from GM states adds to volume of evidence in considering electric vehicles for the Initial Scenarios in the Transmission Inquiry:

> "*The Chevrolet Volt extended-range electric vehicle is expected to achieve city fuel economy of at least 230 miles per gallon, based on development testing using a draft EPA federal fuel economy methodology for labeling for plug-in electric vehicles.*
>
> *The Volt, which is scheduled to start production in late 2010 as a 2011*

[69] Exhibit A-18, Appendix A, Page 5 of 13
[70] Exhibit A-18, Appendix A, Page 7 of 13
[71] Exhibit A-18, Appendix A, Attachment A, Page 1 & 2 of 7
[72] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

model, is expected to travel up to 40 miles on electricity from a single battery charge . . .

The Chevrolet Volt uses grid electricity as its primary source of energy to propel the car."[73]

Discussion of Electric Vehicles

We suggest that the fact that electric vehicles are now being scheduled by America manufacturers for mass production in 2010 shows a clear need for the electrical infrastructure to accommodate the demand and the storage capability of electric vehicles.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that Electric Vehicle technology will need to be accommodated by the BC system. It is anticipated that handling electric vehicles will require smart meter and smart grid technology.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[74]. Therefore, we suggest that at least one of the Initial Scenarios should include Electric Vehicle Technology.

3 Scenario Development:

3.1 Definition of Scenarios for Domestic Electricity Demand in the Transmission Inquiry

In clarifying "*scenarios*" for Provincial Generation Potential, the Inquiry Panel notes: "*BCTC highlighted the difference between scenarios and forecasts, describing a scenario as a construct that will '. . . provide a broad view of the future that may be influenced by a variety of factors (both controllable and non-controllable) including the economy, technology, policy decisions and environmental developments. A particular scenario would not necessarily represent the most likely case, but rather a set of scenarios would represent a range of possible futures. In this context a forecast would describe the load or generation associated with a particular scenario.*"[75]

In clarifying "scenarios" for Assessment of Domestic Electricity Demand, the Inquiry Panel notes: "*BCTC provided a description of scenarios which has been*

[73] Appendix Q, General Motors, "*Chevrolet Volt Expects 230 mpg in City Driving*", August 11, 2009
[74] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[75] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

quoted above in the context of assessment of generation. The same description of a scenario could be applied to future demand."[76]

"*The Panel concurs with the comments in the Staff Paper that a limited number of scenarios be used to group factors that influence demand in order to produce a viable number of options.*"[77]

3.2 Treatment of Scenarios for Domestic Electricity Demand in the Scenario Workshop

On August 5, 2009, BCTC presented a number of slides regarding Scenario Development[78].

Kip Morison presented an overview slide which listed inputs of "*Drivers*" and outputs for each Scenario "*Provincial Potential*", "*Generation Resources*", "*Provincial Load Growth*" and "*Trade*"[79].

Dr. Ren Orans presented a number of slides on the "*Development of Initial Scenarios*"[80].

To identify potential futures, one slide presented in a prescribed order the following[81]:

Range of Potential Futures
Range of Drivers
Range of Outcomes

Seven initial scenarios were presented[82], their descriptions provided[83] and Key Drivers listed[84]. For demand scenarios, three drivers were listed[85]:

Economic growth and regional expansion
Energy efficiency
Electrification: conversion of gas and fossil fuels to electricity

[76] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[77] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[78] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 13 to 27
[79] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 14
[80] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 20 to 27
[81] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 21
[82] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 22
[83] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 23 & 24
[84] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 25
[85] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 25

On the workshop slide labeled "*Build Scenarios: Demand Range*"[86] four rows were included in a table:

Economic Growth
GHG Target
Energy Efficiency
Electrification

3.3 Our Assessment of Scenarios for Domestic Electricity Demand

3.3.1 Assumptions of workshop presentation

We feel that some clarification surrounding these slides would be useful.

First, we assumed that the outputs for each Scenario of "*Provincial Potential*", "*Generation Resources*", "*Provincial Load Growth*" and "*Trade*"[87] in the Overview Scenario slide are examples of specific forecasts as discussed in the Scoping decision[88].

.

We also assumed that the discussions in the Initial Scenario slides[89] revolved around the Drivers[90] and the definition of "*scenarios*" but not intended to address those forecasts[91].

Although not labeled, we assumed that the "*Build Scenarios: Demand Range*" slide[92] listed are intended to be the "Drivers".

[86] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 26
[87] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 14
[88] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[89] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 20 to 27
[90] Drivers, as in slide #14
[91] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[92] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 26

3.3.2 Discussion of Drivers for Demand Scenarios

We note that the Demand "Drivers" presented in the workshop slides did not align with the list provided in the Scoping document:

Scoping Document Demand Drivers	Initial Scenario Slides Demand Drivers
- Economy	- Economic growth and regional expansion
- Technology	- Electrification: conversion of gas and fossil fuels to electricity
- Policy decisions	
- Environmental developments	- Energy Efficiency - GHG (added in table, not in "Key Drivers" slide)

While understanding the need for brevity in a presentation and the challenges it entails, it is not clear of the reasons or intentions for the differences between the Scoping Document and the Initial Scenarios. It is suggested that the next Scenario document clearly establish the link between the Scoping Document Drivers and those used within the Initial Scenarios.

This opens up a myriad of questions: Was it decided that only the most important aspects of the drivers be those listed in the Initial Scenarios? Is it not as important to consider "Policy decisions"? What about other aspects of technology besides "Electrification"? Has all Scoping Document Demand Drivers been considered in the establishment of the Initial Scenarios? Why weren't the Scoping Document Demand Drivers used in the Initial Scenarios? What is lost or gained by changing the list?

It is also suggested that a full description (including assumptions) be included for each Demand Driver – e.g. what is meant by each driver. It is suggested, where appropriate, that a time line of changes within the drivers be discussed as well. We also suggest that a glossary and definition of terms be added, and that this would be a good place to put the driver descriptions.

Here is a starting point for the Driver descriptions (and assumed for use within this document):

Economy: the overall North American economic situation. Unless otherwise stated, it is assumed that the BC economic situation will be in concert with the rest of North America. The economic situation could have normal, higher growth, slowdown, or remain steady. Any abnormality of important segments of the market growing faster or slower than the overall market is

to be noted.

Technology: how technology is used to deal with demand side solutions. The demand side technology is described in both the scale of introduction (how wide spread), and the maturity of the technology (including cost). It is assumed that technology throughout North America, including BC, is roughly at the same level, unless specifically noted.

Policy Decisions: policies which relate to and affect the electrical energy industry. These policies could come in the form of energy plans, provincial laws and acts/statues, regulatory directives & decisions, and similar mechanisms which point the direction of the utilities. It is assumed that each jurisdiction will have its own set of policies, progress at its own timing, and could very well vary between jurisdictions. Therefore, it is important to distinguish whether the policies being discussed are BC policies or from other jurisdictions. As noted in the "Environmental Developments" section below, it is recommended that policies that are driven primarily from an "environmental" point of view, be only discussed within that "Environmental Developments" section.

Environmental Developments: developments addressing a range of issues relating to the environment, energy efficiency, climate change, and pollution. These developments include the energy plans, provincial laws and acts/statues, regulatory directives & decisions, and similar mechanisms relating to these "range of issues", plus the general public's reactions to these "range of issues" which may not be directly due to policies, but instead due to their interest in helping to solve the issues. For consistency, it is recommended that all Environmental Developments, whether policy or not, be discussed within this section. Because of the importance of the 2007 BC Energy Plan and general focus on the environment, we suggest that even though there is some overlap, that the "Environmental Developments" remain as a separate Driver.

We also found the distinction of "*futures*", "*drivers*" and "*outcomes*" blurred and not clear.

We suggest there should be a table which includes at least the four noted Scoping Document Demand Drivers (and the list should be labeled as "Drivers")[93]:

Economy
Technology
Policy decisions
Environmental developments

[93] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

We understand that the list may expand, but we suggest it should contain at least those Drivers noted above.

By including such a table, it helps ensure that the intentions of the Scoping Document are carried through (e.g. considering all factors), clarifies the connection between the Scoping Document and Initial Scenarios and clarifies the terminology of "*Drivers*".

A more specific table (such as in slide #26[94]) could also be included, but if so, it is suggested that it include a clear description of the particular assumptions or considerations taken into account.

While the one sentence descriptions of the Initial Scenarios already used in the Workshop Presentation are useful[95], we suggest that it is also important that a more rigid and structured definition of the Initial Scenarios be also included. We suggest each Scenario should include a clear and detailed definition of at least each of the Scoping Document Drivers noted[96] (economy, technology, policy decisions and environmental developments). All Scenarios other than "Current Practice" should include how they differ (or not) from the "Current Practice" considering that particular Driver. Refer to Section 8 of this document as an example of how we suggest describing a particular Scenario.

The Inquiry Panel suggests that: "*the same description of a [provincial generation] scenario* ***could*** *be applied to future demand.*"[97] [***emphasis added]*** We note that it is not automatic that the demand and generation scenarios would be the same, however, we suggest that the scenarios be the same, as it is less confusing in describing situations in which both generation and demand are to be considered, and is easier for an Integrated approach to be developed.

We have similar suggestions for the Drivers of the Generation Scenarios than we have for the Drivers of Demand Scenarios.

4 Climate Change:

4.1 Climate Change Impacts

[94] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 16
[95] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 23 & 24
[96] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[97] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

Climate Change Impacts refers to the efforts to respond to the impacts of climate changes, rather than providing methods to mitigate climate change.

4.1.1 Climate Change Impacts addressed in the Scoping Document

The Inquiry Panel Scoping document discusses the climate change impacts that are considered in scope: "*The Ocean Renewable Energy Group . . . notes that climate change impact mitigation was not addressed in the Staff Paper. The BC Sustainable Energy Association et al ("BCSEA") and Energy Solutions for Vancouver Island et al ("ESVI") made similar requests. The Panel . . . accepts that climate change impacts may be considered as alternative scenarios or sensitivity tests around future forecasts of hydro generation associated with both reduced inflows and higher demand for low-carbon electricity.*"[98]

4.1.2 Studies on Climate Change Impacts

4.1.2.1 California Climate Change Impact Study

Dealing with the impacts of climate changes (versus trying to mitigate its effect) is a new strategy which is gaining credibility. On August 3, 2009, the state of California "*released a comprehensive plan to guide adaptation to climate change, becoming the first [US] state to develop such a strategy*"[99].

> "*As the climate changes, so must California.*"[100]
>
> "*Adaptation is a relatively new concept in California policy. The term generally refers to efforts to respond to the impacts of climate change – adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of beneficial opportunities.*"[101]
>
> "*Finally, California's hydroelectricity production relies on predictable water reserves. In 2007, nearly 12 percent of California's electricity was produced from large hydroelectric power plants, presently the state's largest source of renewable energy. With snow falling at higher elevations, creating less snowpack, and melting earlier in the year less water is available for this source of power generation when it is needed, during the warmer summer months. When several dry years create drought conditions, reservoir levels can be reduced to levels lower than*

[98] Exhibit A-18, Appendix A, Page 3 of 13
[99] Appendix G, California Resources Agency, Climate Change Strategy Released, Aug 3, 2009
[100] Appendix H, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 5
[101] Appendix H, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 5

those required for hydroelectric power generation."[102]

"*Potential reductions on precipitation levels could significantly reduce hydropower production which currently accounts for up to 20 percent of the state's electricity supply.*"[103]

"*Fluctuations, and possible total reductions, in California's precipitation patterns will impact several key energy and transportation infrastructure components; primarily hydropower production . . .*"[104]

It is recognized that the climate change impacts have large regional variations, and that the effect on BC may vary significantly from California, but it was felt the California report is relevant to the BC Transmission Inquiry, as there are few if any other reports containing the detail of the California report. Also, the very recent release (August 3, 2009) provides up-to-date information and the discussions on Hydropower is very relevant to BC.

4.1.2.2 British Columbia Climate Change Impact Study

A relevant study for Canada was produced by Natural Resources Canada and involved dozens of experts: *"From Impacts to Adaptation: Canada in a Changing Climate 2007 reflects the advances made in understanding Canada's vulnerability to climate change during the past decade."*[105]

One of the chapters deal specifically with British Columbia[106]. The conclusion contains a discussion of key messages and themes:

"***Climate change impacts and the costs of extreme events are increasingly evident but responses and adaptation measures remain reactive.***"[107]

"*Most of BC's alpine glaciers are retreating rapidly and many may*

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[102] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 81

[103] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 119

[104] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 122

[105] Appendix I, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Summary from Website

[106] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia

[107] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 373

disappear in the next 100 years (see Box 1). Coupled with reduced snowpack and warmer spring temperatures, this will result in earlier spring freshets, warmer river temperatures, declining summer river flows and increasing peak flows for many of BC's watersheds (Section 2.4). Impacts on current and future water supplies, hydroelectric power generation, fisheries and river ecosystem integrity are significant concerns for BC."[108]

"***Management of increasingly frequent and severe water shortages will entail complex trade-offs and require improved consideration of climate change.*** "[109]

"*British Columbia's hydroelectric power generation capacity is currently vulnerable to declining water supply and changing river flow patterns, most notably in the Columbia River basin, where more than half of the province's hydroelectricity originates.*"[110]

"*The connection between climate change and water will be an increasingly important consideration in planning to meet many of the key energy production and mitigation strategies outlined in the plan.*"[111]

"***British Columbia's critical infrastructure faces immediate challenges and long-term threats from climate variability and change.***"[112]

"*Extreme weather and associated natural hazards currently present challenges to British Columbia's critical infrastructure, and these impacts are projected to increase as a result of continued climate change. In many places, critical infrastructure, including pipelines, power and telecommunication transmission lines, and transportation networks, are geographically confined to narrow valleys and coastal stretches, and therefore vulnerable to disruption from natural hazards, such as landslides, coastal storms and surges, flooding and forest fires. Research on the impacts of climate change on BC's critical infrastructure systems remains limited, while insurance and costs for*

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108 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 373

109 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

110 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

111 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

112 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

emergency response and recovery are rising (Section 3.8)."[113]

"*Life-cycle cost analysis, return period statistics for extreme events and engineering standards all influence management decisions on how or when to maintain or replace infrastructure. Updating these analyses, statistics and design standards so that they consider climate change impacts and trends will enable managers to better plan for future changes. Institutional constraints remain, however, as many standards and policies that guide infrastructure decisions rely only on past climate statistics.*"[114]

"***Integrating climate change adaptation into decision-making is an opportunity to reduce long-term costs and impacts on British Columbia's communities and economy.***"[115]

A statement with the "Energy" section of the report summarizes: "*In British Columbia, where 89% of the province's electricity is hydro generated (BC Hydro, 2006), the energy sector is highly sensitive to the impacts of climate change on water resources . . .*"[116]

One of the key findings of the report: "*Small hydro and 'run of river' alternatives can increase capacity but are more vulnerable to variable river flows than are facilities with large storage reservoirs. Alternative 'clean' sources of energy, such as wind power, will help meet increasing energy demands in the future, but are currently only a small contributor to BC's power supply.*"[117]

4.1.2.3 Assessment of Climate Change Impacts

Analyzing the impacts of climate change highlights the vulnerability of BC having such a high concentration of one type of power generation – based on hydro.

We suggest that there is sufficient evidence that it is reasonable and

[113] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374 & 375

[114] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 375

[115] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 376

[116] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 352

[117] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 352

plausible to anticipate that BC may in the future recognize that the BC electrical infrastructure needs to be made more reliable in accommodating a wider range of climate and climate-related events. BC would realize a need to diversify the generation mix, and reduce the reliance on hydro. Consequently, BC would provide policies to support regional and local distributed generation, and where larger generation systems are needed, such systems as ocean power or solar farms that do not rely on hydro.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[118]. Therefore, we suggest that at least one of the Initial Scenarios should include the accommodation of Climate Change Impacts as described within this section[119].

4.2 Future price of carbon

4.2.1 Several future price predictions of carbon

The future price of carbon is a complex subject, and could occupy volumes on its own. It is an important subject, as it affects the costs and therefore the types of generation in the future, but time does not permit a comprehensive study.

In order to get a snapshot and a view of the subject, we have compiled a number of carbon pricing studies together[120].

Referencing the pages on the lower right hand side of the package . . .

Appendix J, Page 1: BC's Carbon Tax

Appendix J, Page 2: Various carbon pricing scenarios presented by BC Hydro in the 2008 LTAP up to 2030

Appendix J, Page 3: Table showing BC Hydro's pricing scenario in the 2008 LTAP out to 2050

Appendix J, Page 4: Table showing US pricing as presented by BC Hydro in the 2008 LTAP

Appendix J, Page 5, 6: Table showing most likely scenarios by BC Hydro in the 2008 LTAP

[118] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[119] Section 4.1 and subsections of this document
[120] Appendix J, compilation of various carbon pricing predictions

Appendix J, Page 7: Evidence provided by Dr. Mark Jaccard for IPPBC in the 2008 LTAP

Appendix J, Page 8, 9, 10: Charts developed by National Round Table on the Environment and the Economy

Appendix J, Page 11: David Suzuki report

It should be cautioned that the full content of each table or chart needs to be taken into account, but the compilation does present a viewpoint on the subject.

4.2.2 Discussion on future price predictions of carbon

Essentially, the graph on Page 2 of the carbon pricing Appendix J[121] shows the "*Current Practice*" for BC, as these are the pricing scenarios that BC Hydro has considered for the 2008 LTAP.

We suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that BC may in the future move towards policies supporting and encouraging a more aggressive pricing approach for the future price of carbon as demonstrated in Pages 7 to 11 of Appendix J[122].

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[123]. Therefore, we suggest that at least one of the Initial Scenarios should deal with more aggressive pricing for the future price of carbon.

5 <u>Feed-In Tariffs and Distributed Generation:</u>

5.1 Status of Feed-In Tariffs & Distributed Generation in BC

The 2007 BC Energy Plan clearly includes small distributed generation as an appropriate technique to help achieve its 50% conservation target.

<u>Policy #1:</u>

"***Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.***"[124]

[121] Appendix J, Page 2
[122] Appendix J, Pages 7 to 11
[123] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[124] 2007 BC Energy Plan, Policy #1

"*This may include energy efficiency, conservation, and other demand reduction measures like load displacement, fuel switching (e.g. solar hot water heating) and* ***small distributed generation*** *(e.g. net metering.)"*[125] *[**emphasis added**]*

While energy efficiency and conservation have support funding for incentives in the utilities plans, a July 30, 2009 BCUC Decision for the FortisBC Net Metering application addresses why small distributed generation does not have such incentives for the utilities:

"*The Commission Panel is not persuaded by the Alliance arguments that the payback period should be lessened by incentive pricing. The Province has yet to give direction to the Commission requiring net metering programs to contain incentive pricing. Consistent with the recent Commission decision on the BC Hydro net metering program, an incentive price component is not required as a condition of approval at this time:*

The Province has not yet issued a directive to the Commission with respect to incentive pricing and the specific role of the Net Metering program in achieving conservation objectives. Until the time that such a directive is issued, the Commission cannot presume the details of potential Government policy. The Commission is therefore not persuaded that it should order BC Hydro to include an incentive component into the Net Metering price at this time. (Commission Order G-4-09)"[126]

In the Transmission Inquiry Scoping Document the following points were made in regards to Feed-In Tariffs and Distributed Generation:

"*CPC submitted that distributed generation will play an important role in BC's electricity system, and encouraged the Panel to consider the impact of distributed generation over the 30-year study period and to make recommendations for appropriate development and implementation. ESVI also suggested that 'Feed-in Tariffs' and distributed generation should be within scope for the inquiry.*

The Panel considers the potential impact of distributed generation on the transmission system to be within scope, but recommendations for development and implementation of specific generation to be out of scope. Moreover, the Panel accepts that the potential impact of Feed-In Tariffs is within scope, but if and how the impact of Feed-In Tariffs are incorporated into the analysis depends on the availability of evidence on the issue. The acceptance of the potential impact of Feed-In Tariffs as an in scope issue the

[125] 2007 BC Energy Plan, Policy #1

[126] Appendix K, BCUC Decision on FortisBC Net Metering, July 30, 2009, Appendix A, Page 4 of 6

Inquiry should not be taken as a signal that the Panel will ask BC Hydro or FortisBC to undertake a price elasticity or other new study to provide a detailed estimate of the distributed generation that might be provided at various price levels."[127]

A workshop run by BC Hydro and Rocky Mountain Institute discussed a number of potential solutions relating to Distributed Generation for Vancouver Island[128].

5.2 Studies and Reports on the Status of Feed-In Tariffs & Distributed Generation world-wide

In order to properly assess whether or not to include Feed-In Tariffs or Distributed Generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the implementation throughout the world. This is particularly true of these topics, since there is very little evidence throughout the BCUC filings to determine whether or not it is appropriate for consideration in the Initial Scenarios.

The report, "*PV Status Report 2008 - Research, Solar Cell Production and Market Implementation of Photovoltaics*"[129], written for the Joint Research Centre of the European Commission, provides a table of Feed-In Tariffs and other support mechanisms in Europe[130].

"*Distributed generation of renewables can help to reduce investment in transmission costs. Therefore, there is a unique opportunity at the moment to use the need for an infrastructure overhaul to change to a transmission and distribution systems which will be capable of absorbing the large new quantities of different renewable energy sources, centralised and decentralised all over Europe and the neighbouring countries.*"[131]

Appendix L: *Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments*[132] by Paul Gipe of Wind-works.org, Dec 6, 2008

[127] Exhibit A-18, Appendix A, Page 4 of 13
[128] Appendix R, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003,
[129] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf
[130] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Pages 95 to 100
[131] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 124
[132] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments*"

"Systems of feed-in tariffs have been highly successful at developing large amounts of geographically dispersed renewable sources of generation quickly, at low cost and with minimal administration."[133]

"*Feed-in tariffs are simply payments for generation. They have nothing to do with taxes or subsidies. Thus, feed-in tariffs are more egalitarian because they allow everyone to be paid for their electricity even those who do not pay a lot in taxes."*[134]

"*In Germany in 2007, the average household paid outright less than $50 per year for the world's largest concentration of wind turbines, solar panels, and biomass plants, and the 250,000 new jobs these industries have created."*[135]

"*While feed-in tariffs are also used to develop centralized renewable sources of generation, they are best known for increasing the role of distributed renewable resources."*[136]

Appendix M: *Feed-In Tariffs in America*[137] by Paul Gipe of Wind-works.org, Dec 6, 2008

A summary historical background on Feed-In Tariffs in Denmark[138] and Germany[139] is provided. The rest of the report discusses the applicability of Feed-In Tariffs for the USA.

In conclusion, the report states:

> "*The United States would benefit from a change in renewable energy policy to a feed-in tariff. The lesson from Europe is clear: Americans can continue to debate 'market-based' ideas and tax credits or they can jump to the solutions that work.*
>
> *In addition to turbocharging renewable energy development, a feed-in tariff unlocks the potential of dispersed generation and community ownership. Compared to the byzantine array of incentives and rules facing renewable energy producers, a feed-in tariff decreases the economic and legal costs of doing business and increases the social*

[133] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 1
[134] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 2
[135] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 3
[136] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 3
[137] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009
[138] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Pages 8 to 10
[139] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Pages 11 to 12

and economic benefits."[140]

***State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the United States*[141] for the National Renewable Energy Laboratory by Toby Couture (E3 Analytics) and Karlynn Cory (National Renewable Energy Laboratory), June, 2009**

"*Well-designed FIT policies offer a cost-efficient method for fostering rapid development of RE resources, thereby benefiting ratepayers, RE developers, and society at large.*"[142]

A map of USA shows the introduction of Feed-In Tariffs[143]. Each of the US programs are discussed, with comparisons to the European programs[144].

"*As of March 2009, state representatives have proposed FIT policies in a wide range of U.S. states, including Arkansas, California, Florida, Hawaii, Illinois, Indiana, Michigan, Minnesota, New York, Oregon, Rhode Island, Vermont, Washington, and Wisconsin. California and Washington are examining the possibility of expanding their existing FIT policies (IEPR 2008 and HB 1086, respectively) and Hawaii saw a number of solar FIT proposals in its legislature in 2007. Throughout this flurry of legislative activity, a trend toward designing FIT policies similarly to those found in Europe can be seen. Many jurisdictions that already have either state- or utility-based FIT policies are exploring ways of improving them, and this could help increase the success of FIT policies in the United States in the future.*

In addition to state legislative proposals, governors are also proposing FIT policies. Hawaii, for example, has included a more comprehensive FIT policy within its most recent energy plan (FIT-Hawaii 2009). As part of the Hawaii Clean Energy Initiative, Hawaii identifies reaching 40% of the state's electricity from renewable sources by 2030 as one if its objectives, with the long-term goal of supplying 70% of the state's energy needs with clean energy sources (FIT-Hawaii 2009).

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[140] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Page 30

[141] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009

[142] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page v

[143] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 8

[144] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Pages 8 to 16

State energy offices are also proposing FIT policies. Florida, Ohio, and Maine are considering FIT policies at the state-level (Gipe 2009b), and California recently held hearings at the CEC to examine different policy options for an expanded FIT policy, with the aim of replicating the success of its European counterparts by improving the policy design (CEC 2008).

Finally, the municipalities of Palm Desert, Santa Monica, and Los Angeles in California have also recently proposed FIT policies; however, none were implemented as of April 2009 (Gipe 2009b; Ferguson 2009)."[145]

"*Interest in FIT policies in the United States is expected to continue to grow in coming years. In Europe, the policy has successfully helped deploy significant amounts of RE capacity, across a wide variety of technologies, in a relatively short period of time.*"[146]

The support of Feed-In Tariffs for encouraging distributed generation is highlighted:

"*The United States has a number of utility-based FIT policies which differ considerably in design and effectiveness. They are generally put forth by utilities to help meet utility-specific goals, which may range from meeting RPS targets to encouraging distributed generation.*"[147]

A table listing how the states can achieve their goals through the use of Feed-In Tariffs[148]. It is reproduced on the following page:

[145] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 16

[146] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 31

[147] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 7

[148] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 20

Kirschen 2008). More distributed supply sources can also help reduce line losses while deferring the need for grid upgrades (Bouffard et al. 2008).

Table 3 outlines various policy goals that a FIT policy could help a state achieve.

Table 3. State Policy Drivers

State Policy Drivers	Specific State Policy Objectives	FIT Policy Impacts	Notes
Economic Objectives	Job creation	High	• Due to the guaranteed terms and low barriers to entry offered by FIT policies, they have been highly successful at driving economic development and job creation • Fixed prices for renewable energy sources can also help stabilize electricity rates
	Economic development	High	
	Economic transformation	High	
	Stabilize electricity prices	Moderate	
	Lower long-term electricity prices[12]	Low/Moderate	
	Grow the state economy	High	
	Revitalize rural areas	High	
	Attract new investment	High	
	Develop community ownership[13]	High	
	Develop future export opportunities	High	
Environmental Objectives	Clean air benefits (Mercury, particulates, etc.)	Moderate	• The rapid RE development seen in jurisdictions with FIT policies has helped reduce the environmental impacts of electricity generation, while providing valuable air quality and other environmental benefits. • Differentiating FIT payments by resource type can also target various biomass waste streams.
	Greenhouse gas emissions reduction	Moderate	
	Preserve environmentally sensitive areas	Low	
	Minimize human impacts of energy development	Moderate	
	Manage waste streams (biogas, landfill gas, biomass, agricultural wastes, forestry wastes, etc.)	High	
	Reduce exposure to carbon legislation	Moderate	
Energy Security Objectives	Secure abundant future energy supply	High	• Well-designed FIT policies can improve overall energy security by helping diversify energy supply and helping domestic energy resources be more widely harnessed.
	Reduce long-term price volatility	High	
	Reduce dependence on natural gas[14]	Low/Moderate	
	Promote a more resilient electricity system[15]	Moderate	
Renewable Energy Objectives	Rapid RE deployment	High	• By creating favorable conditions for RE market growth, FIT policies can help jurisdictions meet RE targets. • FIT policies have also helped countries move toward a green energy economy.
	Technological innovation	High	
	Drive RE cost reductions	High	
	Meet RPS targets	High	
	Reduce fossil fuel consumption	Moderate	
	Provide base-load generation	Low/Moderate	
	Stimulate green energy economy	Low/Moderate	
	Reduce barriers to RE development	Moderate/High	

[12] Cost reduction is more likely to be ensured if lower cost RE resources like wind and biogas are included.
[13] Community ownership will depend on how high the payment levels are set, and whether or not communities are able to participate.
[14] Dependence on natural gas will be reduced primarily in areas where natural gas is the marginal supply.
[15] Greater grid resilience will be fostered if more distributed resources are encouraged, and particularly if they are sited in highly congested areas.

Appendix N: *Britain To Launch Innovative Feed-In Tariff Program in 2010*[149] for the National Renewable Energy Laboratory by Toby Couture (E3 Analytics) and Karlynn Cory (National Renewable Energy Laboratory), June, 2009

The ramifications of Britain's Feed-In Tariff introduction in 2010 is perhaps best stated in the following:

> "*The move {Britain introducing a Feed-In Tariff] has potentially far reaching ramifications in the English speaking world where there has been reluctance to use full-fledged systems of feed-in tariffs, sometimes on ideological grounds. Now that Britain, Ontario, and South Africa, two of Britain's former colonies, have definitively moved toward implementing sophisticated feed-in tariff programs, there may be less reticence to do so elsewhere in the Anglophone world.*"[150]

Appendix O: *Ontario Unveils North America's First Feed-In Tariff*[151] by the Ontario Power Authority, March 12, 2009

Feed-In Tariffs are also provided in Canada, where Ontario is in the process of updating their Feed-In Tariff program:

> "*The proposed feed-in tariff program would help spark new investment in renewable energy generation and create a new generation of green jobs, " said George Smitherman, Deputy Premier and Minister of Energy and Infrastructure. "It would give communities and homeowners the power and tools they need to participate in the energy business in the new green economy.*"[152]

Appendix P: *Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario*[153] by the Ontario Power Authority, July 8, 2009

On July 8, the latest updated pricing for the Feed-In Tariffs were adjusted from its March 12 announcement, and included Aboriginal (First Nations) and Community price adders.

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149 Appendix N, Paul Gipe, "*Britain to Launch Innovative Feed-In Tariff Program in 2010*", July 23, 2009
150 Appendix N, Paul Gipe, "*Britain to Launch Innovative Feed-In Tariff Program in 2010*", July 23, 2009
151 Appendix O, Ontario Power Authority, "*Ontario to Unveils North America's First Feed-In Tariff*", March 12, 2009
152 Appendix O, Ontario Power Authority, "*Ontario to Unveils North America's First Feed-In Tariff*", March 12, 2009
153 Appendix P, Ontario Power Authority, "*Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario*", July 8, 2009

Premier's Technology Council 10th Report[154] **for the Premier's Technology Council, September, 2007**

Based on the 2007 BC Energy Plan, the BC Technology Council, chaired by the Premier Gordon Campbell and supported by a large group of respected individuals[155] discussed and recommended Feed-In Tariffs and Distributed Generation in its report.

One of its recommendations specifically addressed Feed-In Tariffs. Find the recommendation listed below (***in bold***) with supporting statements following that recommendation:

> "***That government support the development of appropriate feed-in tariffs that decline over time to assist the commercialisation of emerging, renewable energy sources and their associated technologies.***"[156]
>
> > "*To drive the development of alternative, renewable, cost-effective energy technology and meet the goals of the Energy Plan, BC Hydro must make some changes in the way it purchases electricity, in particular green power.*"[157]
> >
> > "*More aggressive options need to be considered such as a feed-in tariff system that varies by the source of renewable energy and the maturity of the technology. These kinds of tariffs are being successfully deployed in Europe and elsewhere.*"[158]
> >
> > "*It is important to take a long-term view of supply, and while certain power supply technologies will not be commercial for some time – such as ocean energy from waves or tides – they will eventually be needed, and BC is in a good position to develop an industry around these technologies. Appropriate feed-in tariffs can be a powerful stimulus to the industry.*"[159]

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154 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007

155 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 124 to 127

156 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 49, Recommendation 10.21

157 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 47

158 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

159 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

"*Legislation that governs the energy system mandates that higher rates be paid for power supplied by deploying emerging technologies.*"[160]

A number of other recommendations are related to distributed generation:

"***That government continue to pursue its goal of self-sufficiency by 2016.***"[161]

"*At the same time, such a firm target could act as an incentive to address other challenges facing the renewable energy industry. It would demand a build-out of advanced infrastructure, in particular transmission lines and a 'smart' grid to allow for distributed generation and technology-driven conservation.*"[162]

"***That government direct BCUC to consider the broader goals of government in its monitoring role, in particular the objectives of the Energy Plan. Examples of specific measures that need to be considered are:***

Investment in infrastructure, including smart grid technologies, to allow access to more supplies and enable system efficiencies; . . "[163]

"*First, the utility will need to make large investments in infrastructure to build a grid system that can support both conservation and distributed generation.*"[164]

"***That government direct BCUC to consider government policies for conservation and renewable energy when reviewing the long-term strategic plans of the utilities to invest in a 'smart grid' digital power infrastructure.***"[165]

"*Still more projects might be small-scale, such as photovoltaic*

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[160] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

[161] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 32, Recommendation 10.9

[162] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 31

[163] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 33, Recommendation 10.11

[164] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 32

[165] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 36, Recommendation 10.13

panels on a building. Such 'distributed generation' calls for careful micromanagement of data and electricity flows, and possibly net metering on facilities that will sometimes draw from the grid and sometimes feed into it. Currently, the system is not sophisticated enough to manage these required elements of the Energy Plan."[166]

"***That government continue to advance the Green Cities Project and the Green Building Code, through the mandating of green targets and promoting the use of green technologies.***"[167]

"*All three options should exist, but the third option is particularly critical as performance based compliance paths provide the most opportunity to incorporate advanced technologies such as distributed (co)generation, solar thermal and geo-exchange into building design.*"[168]

5.3 Discussion on Feed-In Tariffs and Distributed Generation

As described within this section of the document[169], Feed-In Tariffs and Distributed Generation are gaining support in various parts of the world (of particular interest to BC, the USA and Ontario). There are many benefits, including the benefits as shown in "State Policy Drivers" table[170]. In addition, the Premier's own Technology Council has recommended Feed-In Tariffs and Distributed Generation[171], and it seems only a matter of time before Distributed Generation include incentives like energy efficiency and conservation in order to help achieve the conservation targets of the BC Energy Plan.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that BC may in the future move towards policies supporting and encouraging Feed-In Tariffs and Distributed Generation.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[172]. Therefore, we suggest that at least one of the Initial Scenarios should include Feed-In Tariffs

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166 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 35

167 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 44, Recommendation 10.16

168 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 43

169 Section 5.0 of this document and all subsections

170 www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Pages 20

171 Discussion of the "Premier's Technology Council 10th report" (Appendix U) within Section 5.2 of this document

172 Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

and Distributed Generation.

6 Solar:

6.1 Solar as discussed in the Transmission Inquiry Scoping Document

In the Transmission Inquiry Scoping Document[173], the Inquiry Panel notes:

> "*ESVI also suggested that 'the regional aspect for wind be expanded to include the regional considerations for solar'. The Panel understands the examples in the Staff Paper to be illustrative and that the cost estimates for various generations resources (especially developing technologies, including both wind and solar) will have regional considerations.*"[174]
>
> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference . . .*
>
> > *Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation such as wind, solar, wood waste, other bioenergy, geothermal, ocean (wave, tidal and in-stream current), or other such renewable generation resource that is anticipated to be commercial or near commercial*"[175]
>
> "*Similarly, scenarios could be developed with assumptions favourable to run-of-river generation, to ocean (wave, tidal and in-stream current) generation, to solar generation, or to coal generation with carbon capture and storage, and such scenarios would tend to increase or decrease the generation forecasts in various regions depending on the supply resource options in each region.*"[176]

[173] Exhibit A-18
[174] Exhibit A-18, Appendix A, Page 5 of 13
[175] Exhibit A-18, Appendix A, Attachment A, Page 1 of 7
[176] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

6.2 Reports and Papers addressing Solar generation

In order to properly assess whether or not to include Solar generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the aspects important for such considerations: the predicted future of solar technology and its costs. There is very little solar generation in BC at present, yet that situation is bound to change in the future as the technology improves and costs fall.

6.2.1 Solar-related activities in the United States – Department of Energy

While there are many efforts around the world working at enhancing the solar technologies, a view of the US Department of Energy (DOE) activities could serve as an appropriate example of those world-wide efforts.

DOE has a multi-prong approach for solar technologies.

There are a number of early commercialization programs which DOE provides millions of dollars in funding to help foster the developments.

Next Generation Photovoltiac:

"*The Next Generation Photovoltaic (PV) Devices and Processes projects represent innovative, revolutionary, and highly disruptive next-generation PV technologies. These PV research and development (R&D) activities within the Solar Energy Technologies Program are expected to produce prototype PV cells and/or processes by 2015, with full commercialization by 2020-2030.*"[177]

Photovoltaic Pre-Incubator:

"*The Photovoltaic (PV) Technology Pre-Incubator project helps small solar businesses transition from concept verification of a solar PV technology to the development of a commercially viable PV prototype by 2012.*

The goals of the project include promoting grid parity for PV technologies, transitioning innovative PV technologies into the prototype stage, and developing prototype PV concepts with manufacturing costs of less than $1/watt."[178]

Photovoltaic Incubator:

"*The PV Incubator awards target research and development of PV systems and component prototypes with full functionality, produced in*

[177] www1.eere.energy.gov/solar/next_generation_pv.html
[178] www1.eere.energy.gov/solar/pv_preincubator.html

pilot-scale operations."[179]

There are also programs in which the technologies are close to mass production, including the Technology Pathway Partnerships (TPP) [180] program:

The objectives of the TPP Program include:

"*Accelerate development of U.S.-produced PV systems so that PV-produced electricity reaches parity with the cost of electricity in grid-tied markets across the nation by 2015.*"[181]

"*Research toward lowering the cost of electricity from PV to $0.05 - $0.10 per kWh by 2015 –a price that is competitive in markets nationwide. [Range given because of various applications (i.e., residential, commercial, utility)]*"[182]

Thirteen technology programs, including their cost projections, are listed in the TPP presentation[183]. Cost projections for each technology in 2015 are shown in one graph on Slide #14[184] (note that not all companies have listed their expected manufacturing volumes).

A graph of the range of historical and predicted costs of solar technology compared to utility costs is included on Slide #2[185] of the TPP presentation.

6.2.2 World wide solar developments

The report, "*PV Status Report 2008 - Research, Solar Cell Production and Market Implementation of Photovoltaics*"[186], written for the Joint Research Centre of the European Commission, provides a world wide view of the solar technologies.

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[179] www1.eere.energy.gov/solar/pv_incubator.html

[180] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007

[181] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #3

[182] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #5

[183] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slides #16 to #28

[184] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #14

[185] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #2

[186] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf

The world-wide production of PV cells and modules from 1990 to 2007 shows a dramatic increase, with an estimated 4 GW world-wide production in 2007[187]. By 2012, this volume is expected to increase ten-fold to over 42 GW[188].

Numerous solar technologies developments in Japan, People's Republic of China, Taiwan, the United States and the European Union are described in the report[189].

A study called "*Scoping Study on Financial Risk Management Instruments for Renewable Energy Projects*"[190] written for the United Nations Environment Programme under the Sustainable Energy Finance Initiative shows a table with projected future costs of a range of technologies – with Solar technologies beyond 2020 projected to drop to 5 to 8 cents/kwh[191].

6.2.3 Solar in Canada

A key issue, which will be dealt with in more detail within the Resource Options work for the Transmission Inquiry to be done by BC Hydro (deadline August 14), is the suitability of solar for BC – solar thermal energy, in commercial form, is already competitive in price to other energy forms in BC. This will include among other aspects, the resource characterization and the analysis of the "Potential Solar Insolation" provided by BC Hydro in the Resource Options workshop.

We suggest that BCTC in developing its Initial Scenarios take into account the information and comments provided to BC Hydro on its Resources Options work (not only for solar, but also for all other areas).

6.3 Discussion on Solar Generation

We suggest that the US DOE developments show numerous technology developments in which the solar pricing projections are expected to come close to compete to utility energy costs by 2015[192]. In addition, there are even larger world-wide initiatives outside the US, which could have lower costs yet.

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[187] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 5
[188] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 11
[189] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Pages 18 to 121
[190] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf
[191] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf, Page 52, Table 8, "Grid connected photovoltaic", 1000 and 1500 kWh/m^2
[192] Section 6.2.1 of this document

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that solar technology may have an increasing role for BC.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[193]. Therefore, we suggest that at least one of the Initial Scenarios should include Solar Technology generation.

7 Ocean Generation:

7.1 Ocean Generation as discussed in the Transmission Inquiry Scoping Document

In the Transmission Inquiry Scoping Document[194], the Inquiry Panel notes:

> "*The Ocean Renewable Energy Group suggested broadening the term 'Ocean (wave and/or tidal current)' as used in the Staff Paper to 'Ocean (wave, tidal and in-stream current)' . . . The BC Sustainable Energy Association et al. ('BCSEA') and Energy Solutions for Vancouver Island et al. ('ESVI') made similar requests. The Panel agrees to the use of the broadened description as suggested . . .*"[195]

> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference . . .*

> > *Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation such as wind, solar, wood waste, other bioenergy, geothermal, ocean (wave, tidal and in-stream current), or other such renewable generation resource that is anticipated to be commercial or near commercial*"[196]

> "*Similarly, scenarios could be developed with assumptions favourable to run-of-river generation, to ocean (wave, tidal and in-stream current) generation, to solar generation, or to coal generation with carbon capture and storage, and such scenarios would tend to increase or decrease the generation forecasts in various regions depending on the supply resource options in each region.*"[197]

[193] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[194] Exhibit A-18
[195] Exhibit A-18, Appendix A, Page 3 of 13
[196] Exhibit A-18, Appendix A, Attachment A, Page 1 of 7
[197] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

7.2 Ocean generation technology

We note that BC Hydro will be developing the "*Resources Options*" portion of the Transmission Inquiry and gathering input from Intervenors regarding this aspect. We suggest that the evaluation of Ocean generation for use in the Initial Scenarios is particularly difficult to pursue without the full input from the "Resource Options" section due to its location-specific characteristics and information expected to be contained in the "Resource Options" section.

We suggest that BCTC in developing its Initial Scenarios take into account the information and comments provided to BC Hydro on its Resources Options work (not only for ocean, but also for all other areas).

In spite of this situation, we will present our comments within this document, our comments on Scenarios.

In order to properly assess whether or not to include Ocean generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the aspects important for such considerations: the various potential ocean technology techniques and its costs.

A report called "*Inventory of Canada's Marine Renewable Energy Resources*"[198] for the Canadian Hydraulics Centre of National Resource Council Canada and written by A. Cornett provides useful information Ocean Technology.

> Examples of the various types of technologies are shown on pages 3 to 5 of the report[199].
>
> The annual and monthly mean wave power is shown for 30 stations along the west coast of BC[200]. It shows particularly large numbers in winter, which is the traditional high demand time of the BC system. For example, six stations have higher than 70 kw/m for the months of November to February and eleven stations higher than 70 kw/m in January. A graph shows the normalized seasonal variation[201]. Maps show the mean wave power along the west coast of BC, including summer and winter[202].
>
> Tables show the tidal potential in BC, regions of BC, and stations[203] with also with map locations[204].

[198] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf
[199] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 3 to 5
[200] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 20
[201] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 23, Figure 13
[202] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 31, Figure 18 & Page 32, Figure 19
[203] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 83 to 87
[204] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 95

A study called "*Scoping Study on Financial Risk Management Instruments for Renewable Energy Projects*"[205] written for the United Nations Environment Programme under the Sustainable Energy Finance Initiative shows a table with projected future costs of a range of technologies – with Ocean technologies beyond 2020 projected to drop to 5 to 15 cents/kwh[206].

The dropping costs of wave power[207] and tidal stream[208] are presented by the Carbon Trust in a study called "*Future Marine Energy*"[209].

A report on a workshop done by BC Hydro and the Rocky Mountain Institute states:

> "*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.*"[210]
>
> "*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.*"[211]
>
> "*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.*"[212]

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[205] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf

[206] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf, Page 52, Table 8, "Marine Energy"

[207] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy", Pages 19 & 20

[208] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy", Pages 21 & 22

[209] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy"

[210] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 37

[211] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 38

[212] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 38

7.3 Discussion on Ocean Generation

We suggest that there is a wide range of Ocean technologies that could be adapted to the BC coast[213]. We suggest that there is a large energy potential, and that it is particularly favourable to generation in the peak demand requirement times of the BC system load – in winter[214]. We suggest that Ocean technology supports higher system reliability through diversity (allows for adapting to climate change[215]) and supports the BC economy.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that ocean technology may have an increasing role for BC.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[216]. Therefore, we suggest that at least one of the Initial Scenarios should include Ocean Technology generation.

8 <u>Suggested Initial Scenario:</u>

8.1 Description of Suggested Initial Scenario

In response to the request for comments from the Scenario Workshop, we will describe within this section a scenario that we believe to be appropriate. It is based upon the background provided in Section 3 "*Scenario Development*"[217] and is in essence an expanded version of the "Integrated Non-Wires" Scenario, discussed in Section 1, let's call it "Expanded Integrated Non-Wires".

"**Expanded Integrated Non-Wires**" Scenario:

Economy: The value of encouraging and enhancing the BC clean energy and regional economy is recognized. Appropriate mechanisms and policies are implemented to ensure that such a long term sustainable green economy is developed in BC[218].

Technology: The technologies for sophisticated demand side management

[213] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 3 to 5
[214] Discussed in Section 7.2 of this document
[215] Discussed in Section 4.1 and its subsections of this document
[216] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[217] See Section 3.0 "*Scenario Development*" and its subsections of this document
[218] "*create economic opportunities in British Columbia*": Terms of Reference, Page 5 of 7, Item 8(b)(vi)

result in higher levels of conservation and costs are reduced[219]. Distributed[220], Solar[221] and Ocean[222] generation costs drop significantly, and these technologies become more prevalent.

Policy Decisions: For this scenario, it is assumed that the high cost and uncertainty of land issues relating to new transmission lines has encouraged BC to adopt a fully integrated "*Non-Wires*" solution approach (look proactively at solutions other than transmission lines, such DSM and strategic renewable generation placement) similar to those outlined with the Bonneville Power Administration as described with Section 1.0 of this document[223].

BC policies are incorporated to place higher emphasis on regional solutions and appropriately consider seasonal characteristics of generation.

BC policies, such as those supporting Feed-in Tariffs and Distributed Generation[224], are implemented to encourage higher reliability and security of the transmission system through diversity of generation location (distributed generation[225]) and technology selection.

Environmental Developments: In the early years of the 30-year study period, it becomes clear that the projected cost of carbon and greenhouse gas emissions will rise significantly in future years as described in Section 4.2 of this document[226], and therefore BC policies are implemented to anticipate these upcoming costs, and further encourage low-carbon or no-carbon solutions. In later years of the study period, the projected high costs come to fruition.

In the early years of the study period, it is recognized that the looming climate change crisis and climate change science hit a critical point such that climate change impacts need to be considered to ensure BC continues to have a reliable electrical transmission system even if the climate changes, and weather conditions are extreme as described in Section 4.1 of this document[227]. BC policies are implemented to ensure that DSM is further encouraged[228], electric vehicles prevalent with

[219] See Section 2.2.1
[220] See Section 5.0 "*Feed-In Tariffs and Distributed Generation*" and its subsections of this document
[221] See Section 6.0 and its subsections in this document
[222] See Section 7.0 and its subsections in this document
[223] See Section 1.0 "*Non-Wires Initial Scenario*" and its subsections of this document
[224] See Section 5.0 "*Feed-In Tariffs and Distributed Generation*" and its subsections of this document
[225] See Section 5.0 and its subsections in this document
[226] See Section 4.2 "*Future price of Carbon*" and its subsections of this document
[227] See Section 4.1 "*Climate Change Impacts*" and its subsections of this document
[228] See Section 2.2.1

appropriate rate structures[229] (drawing on the grid and acting as storage for the grid), and that the supply/generation of the BC electrical system is diverse in technology and does not so heavily rely on large hydro – instead distributed generation[230], solar[231] and ocean[232] generation are encouraged.

[229] See Section 2.2.2
[230] See Section 5.0 and its subsections in this document
[231] See Section 6.0 and its subsections in this document
[232] See Section 7.0 and its subsections in this document

APPENDICES

Expansion of BPA Transmission Planning Capabilities

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Appendix A

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Executive Summary

Transmission Planning and Expansion Framework

Bonneville Power Administration's (BPA) Transmission Power Line (TBL) has proposed transmission infrastructure investments totaling $775 million above previously planned capital expenditures. Should TBL choose to move forward with any or all of these additions, it will have to take them through the National Environmental Policy Act (NEPA) process. In that process, TBL will need to determine how these projects affect the environment relative to alternative actions it could take, and it will have to justify these transmission additions to a variety of stakeholders.

TBL has added virtually no circuit miles to its transmission system since the late 1980s. During this lengthy period, however, electrical demand in the Pacific Northwest has continued to grow (BPA has experienced a 1.8% annual growth in demand over the past 15 years). Equally important, the increasingly competitive nature of wholesale electricity markets is leading to energy transactions and power flows that differ substantially, both in magnitude and directions, from historical practice. Transmission planning has to evolve to keep up with this changing environment.

The future promises more changes in utility practice and transmission planning with the introduction of RTOs. In October 2001, FERC held a series of workshops (called "RTO Week") to discuss electricity market design and structure. From the panel discussion on transmission planning and expansion the following points of consensus were identified:[1]

> A regional transmission plan with representation from all stakeholders is the best way to perform transmission planning and expansion.
>
> Market driven solutions [to transmission problems] are best.

Before proceeding with the construction of transmission projects, BPA wants to ensure that there is a clear and compelling demonstration of project need and that it is providing the most cost-effective solution to the region's transmission problems from an engineering, economic and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions can include pricing strategies, demand reducing strategies, and strategic placement of generators.

In many respects these nonwires activities have been outside of TBL's purview and TBL has had to be passive with respect to them. If they happen, TBL can account for them, but it cannot make them happen. Other regional stakeholders that control nonwires activities and, in so doing, affect system costs and topology, include BPA's Power Business Line (PBL), other regional utilities, merchant generators, state regulatory commissions, loads, and possibly others. This separation of

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[1] FERC Docket No. RM01-12-000

responsibilities, without coordination, has made it difficult to develop a bulk power system that in its entirety, from generation to retail-customer loads, provides the lowest-cost electricity and delivery system to retail consumers in the region.

If TBL and other regional players acted in concert, it is much more likely that they could create a system that is lower-cost and more reliable than would be the case if each acted alone. It may be possible to achieve these goals through market discipline when RTO West is operational. However, an operating RTO may be several years away, and we believe that the following recommendations apply both to BPA today and to RTO West in the future.

Summary of Conclusions

We recommend that TBL engage regional stakeholders in its planning process with the goal of sharing information that would lead to a more efficient region-wide system. The report suggests an approach for BPA to provide these stakeholders with the information they need to identify and construct potentially lower-cost and reliable alternatives to transmission expansion. In addition, TBL could employ transmission-pricing strategies that encourage economically efficient behavior, including the suitable location of new generating units and the timing of electricity use.[2]

Proposed Planning Process and Its Implementation

In Sections 1 and 2 of this report, we recommend that TBL adopt two new elements to its already comprehensive planning process (Fig. ES-1):

1) The production of a biennial system-wide report that describes the expected use of BPA's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate BPA's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as building new generation in certain locations.

2) The refinement and implementation of TBL's existing planning process to screen specific proposed transmission projects against the costs of various forms of suitably located and operated generation, load management, and transmission pricing.

These steps are included in Figure ES-1, which depicts the entire planning process.

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[2] Implementing non-postage-stamp transmission-pricing strategies now could provide a good test for RTO West of the efficacy of its contemplated locational pricing scheme, and would help to make the RTO a more effective steward of the transmission system.

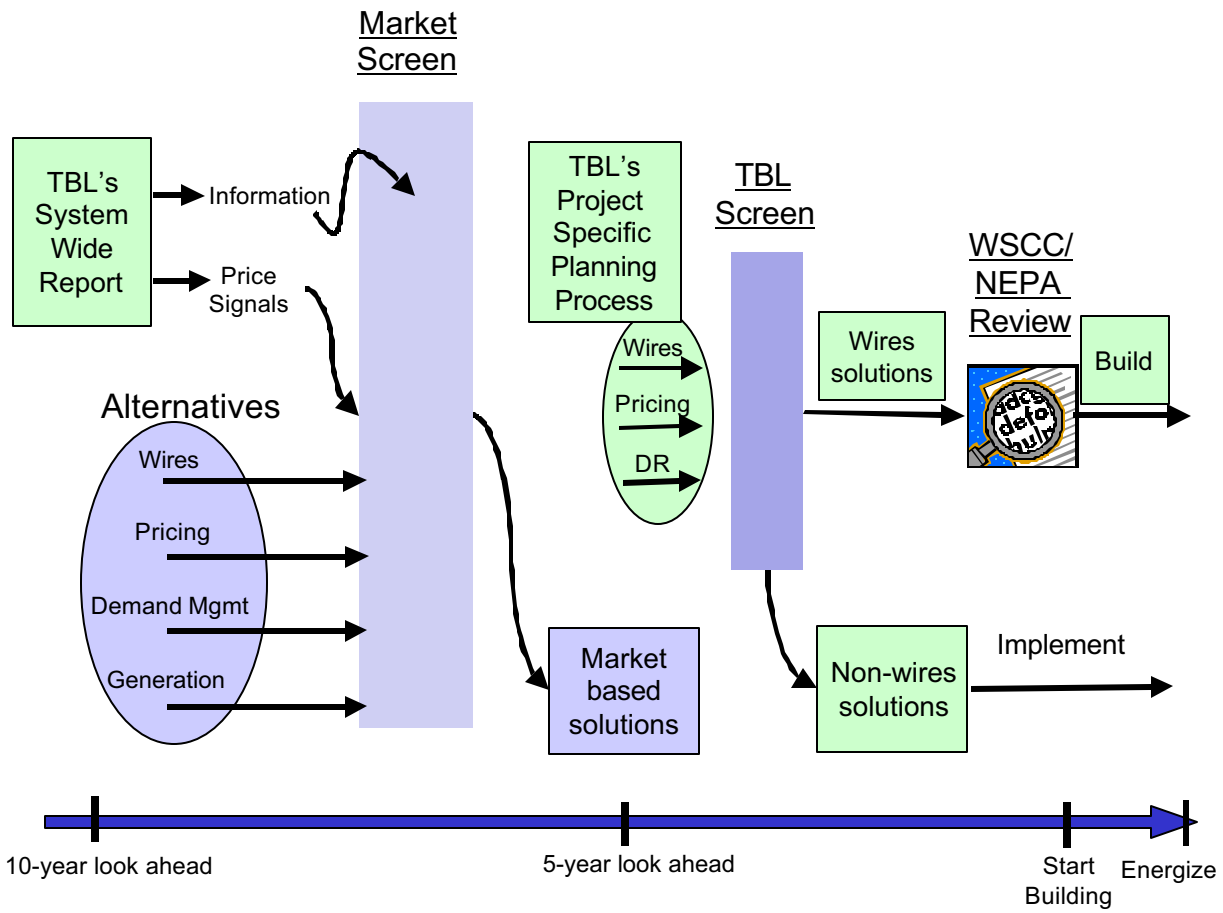

Figure ES-1: The Multiple Screening Process

Specific Recommendations

TBL can take the lead in developing a regional transmission plan, but both development and implementation of the plan should be a regional effort involving many interested and affected players. Ultimately, these regional choices should be made in concert with other Northwest interests. We suggest a detailed approach to coordinated decision making, throughout the planning process, moving from longer-term region-wide perspective to a shorter-term project-specific screening process as the time for action nears.

Revised Transmission Planning: Region-Wide Perspective.

TBL can be the catalyst that brings regional decision makers together to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. A proposed set of steps follows:

1. TBL should produce a long-term view of the transmission plan that includes expected congestion points, and the associated long-run differential costs of delivering power to various points on the grid. (See Section 2 for a detailed discussion of the long-run incremental costs of transmission expansion.) At this stage, TBL could raise the idea and

the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into detailed discussions of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate the problems identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design.

5. TBL will have a number of options available to it at this point, as follows:

    a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the project-specific screening process proposed herein. As suggested in Figure ES-1, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

    b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

    c. It may decide that locational and time-sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

    d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

    e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

Revised Transmission Planning: Project Specific Perspective

We identified a need to broaden TBL's consideration of nonwires alternatives. As the need for investment in specific wires or nonwires solutions nears, *the project-specific screening process* should be implemented. To refine this process, we recommend taking two of the currently

proposed G-20 projects through this screening process. (The screening process is discussed in Section 2.) The two projects would be put through all steps of the screening process in concert with TBL staff. This effort would refine the proposed screening process and help decide whether economic and reliable alternatives exist to delay transmission construction of either or both projects.

The first stage of the project-specific screening process identifies those projects that cannot be solved by nonwires alternatives and those that have viable alternatives. (See the discussion screening projects into "buckets" in Section 2.) Many of the projects included in TBL's proposed projects are driven by the need to interconnect new generators or are too far along in the process to identify suitable alternatives to them.

Of the remaining G-20 projects, we identified two for detailed projected specific screening that will address different issues that arise with respect to transmission expansion.

- G-8 is a project that crosses sensitive environmental areas, and the decision to construct is far enough out in time to provide a potential benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound.

- G-12 is proposed to serve expected load growth on the Olympic Peninsula. We recommend that G-12 be the other project that is put through the full screening process, again, in concert with TBL staff.

In summary, this project reviewed BPA's current transmission-planning process and identified potential additions to that process to strengthen its relevance to expanding wholesale power markets in the Northwest. Our recommendations focus on nonwires solutions to transmission problems, with suggestions on how to consider such alternatives to traditional "wire in the air" projects in both long-term and project-specific planning.

List Of Acronyms

BPA	Bonneville Power Administration
DG	Distributed generation
DSM	Demand-side management
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission
ISO	Independent system operator
LICR	Long-run incremental cost
NEPA	National Environmental Policy Act
NWPP	Northwest Power Pool
PBL	Power Business Line
RTO	Regional transmission operator
TBL	Transmission Business Line
VOS	Value of service
WSCC	Western Systems Coordinating Council

Section 1: Proposed Planning Process

1.0. Introduction

The purpose of the suggested changes to TBL's transmission planning process is to make the process more proactive and expansive in identifying and resolving transmission problems at the lowest cost to the transmission system, thereby improving TBL's ability to meet the needs of its customers. This process could be implemented over the next three years, in time for full implementation for projects with start dates in 2004. The recommended process includes the addition of two new functions and the modification of several others.

The two new functions are:

1. The production of a biennial system-wide report that describes the expected use of TBL's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate TBL's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as the location of new generation plants.

2. A two-part screening process for TBL's transmission projects to identify those projects that have viable nonwires alternatives. This can be viewed as a "backstop" project-specific screen performed by TBL to find nonwires alternatives that may have been missed in the system-wide market process initiated by the biennial report described above as function 1.
   a. The first is a high level screen to identify transmission problems that cannot be solved by nonwires alternatives. These are transmission projects that do not have viable alternatives because of generation interconnection, contract, or safety obligations.
   b. The remaining transmission projects, for which viable alternatives might exist, will be screened against the costs of strategically located and operated generation, demand management, and transmission-pricing programs.

For all planned investments with start dates before 2004, we propose an interim screening approach that includes the high level screen described above in 2a, and also identifies transmission projects that do not have viable alternatives because they require immediate solutions. The application of this interim screening process is described in Section 2.1 and the process is applied to the TBL planned projects G1 through G20.

1.1. Existing Transmission Planning Process

Figure 1 shows a simplified version of TBL's existing transmission planning process. While designed to meet the anticipated needs of its transmission customers, the process is reactive in that it is almost always driven by events external to TBL. These events are called project drivers and include requests for generation or customer interconnection, or the need to comply with

legal, regulatory, safety or reliability requirements.[3] These drivers then lead to screening, evaluation, development of options, selection of the preferred plan, various reviews to ensure compliance with NERC and WSCC reliability requirements, regional planning processes under WSCC and NWPP and with the National Environmental Policy Act, and finally an implementation process that includes construction and rate-making[4].

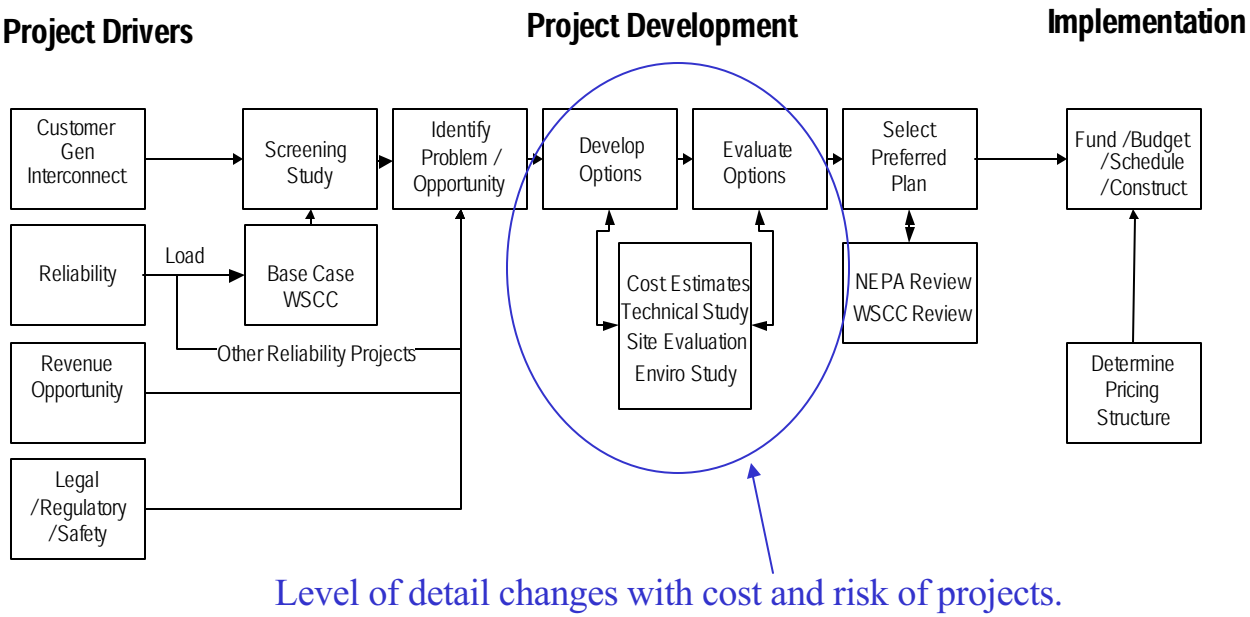

Figure 1: Simplified Existing TBL Planning Process

Although the existing TBL planning process is consistent with best practice industry standards, it identifies transmission needs on a schedule that is too late for implementation of nonwires alternatives. For example, a TBL-funded load-reduction program, designed to solve one of its transmission constraints and replace a wires expansion project, would have to be put in place long before the project's in-service date. The in-service dates for the current set of G1-G9 projects are four years or less in the future, whereas a coordinated demand reduction project may take five years to fully implement and therefore may be a nonviable alternative.

Reactive transmission planning processes are not conducive to finding cost-effective and feasible nonwires alternatives. A longer term, system-wide planning process is needed as a supplement to the existing process.

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[3] In a few cases new revenue opportunities may drive the need for new construction.

[4] See, for example, the BPA Infrastructure Addition Summary at: http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/defaultfiles/slide0001.htm

1.2. Creating a 10-Year Planning Study

The goal of the suggested system-wide transmission planning study is to identify future problems and requirements on the transmission system in sufficient time to solicit market-based solutions that are less expensive than transmission expansion. These market-based solutions will be funded by private investors who accept all risks for the project's success. That is, the returns on the investment will not be determined or guaranteed by a government regulator, but rather by competitive markets. The system-wide transmission planning study should look out over a 10-year horizon and be updated on a regular basis, i.e., biennially. This will allow sufficient time for market response and for the implementation of long-lead-time projects, such as the construction of large generation facilities.

The study should develop a broad consensus on new transmission and/or nonwires projects that are needed and that get built in a timely and cost-effective fashion. The categories of potential transmission and nonwires activities include the following:

1. Transmission expansion that is built within rate base for a FERC-regulated entity (or the equivalent) with regulated transmission rates;
2. Merchant transmission financed through market-based revenues;
3. Wholesale and retail pricing strategies for energy and transmission that reflect temporal and locational variations in costs;
4. Demand Management:
    a. Energy efficiency programs
    b. Load-shifting programs,
        i. Reliability management (energy and ancillary services),
        ii. Economics (price) based
5. Strategically placed generation plants within the transmission grid or underlying distribution system, including distributed generation.

The goal is to rely primarily on market-based solutions to transmission problems that are engendered by information from TBL that informs expectations of prices. However, BPA transmission operators should continue the existing TBL project planning process. This on-going process will be used to manage transmission problems that are serious and persistent, do not have a market based solution, and require a timely intervention and resolution.

We understand that TBL already has plans to resurrect its long-term planning process to produce better market information. The system-wide study we are proposing should be a natural extension of that effort.

Under this proposed process, once every other year TBL will produce a System-Wide Planning Study. The study will consist of the following steps:

1. Describe the current electricity situation, covering bulk-power operations, wholesale markets, and transmission pricing. Include transmission projects to which commitment has already been made.

2. Perform a 10-year load forecast that produces a range of plausible load scenarios. (Refer to Section 1.3 for recommendations on conducting a load growth forecast.)

3. Identify existing and potential problems (e.g., reliability, congestion, losses, generator market power) that are caused by the current and anticipated limitations of the transmission system. Report on the conditions under which the problems appear (e.g., certain hours, seasons, weather conditions, load forecasts, etc.).

4. Determine if the problems identified in Step 3 are chronic, and whether they are expected to persist without transmission upgrades or expansions, or without the implementation of nonwires solutions.

5. Based on steps 1 through 4, construct a set of alternative TBL expansion plans over the ensuing 10 years, under different scenarios of loads, generation development, transfers, regional power-flow patterns, etc.

6. Translate base-case expansion plans into expected long-run incremental costs (LRIC) of transmission expansion by zone or across major flowpaths. (See Section 2 for an explanation of the LRIC estimation.)

7. Identify feasible ways to provide efficient transmission-price signals (including charges for access, congestion, and losses) and conduct an aggressive public outreach to ensure as broad an understanding[5] as possible. Potential methods for pricing include cooperative programs with BPA's customers and structural pricing solutions.[6]

The implementation of this seven-step process would result in the following time line. Every potential transmission project would appear on the market participants' radar screens at least ten years before the project need date. The information would be updated on a biennial basis. TBL would develop a variety of incentives to encourage efficient behavior for the period running up to the project need date.

At least five years prior to the projected need date, TBL would run its project specific planning process. Closer to an expansion need date, TBL would produce more refined forecasts of load growth and other requirements on the transmission system, and would screen for smaller scale generation resources and other nonwires solutions in addition to transmission construction. A transmission project would undergo regional and NEPA reviews only after it has been exposed to (a) market forces to identify and encourage market solutions and (b) TBL's supplemental programs and screening processes. This multiple screening process is depicted in Figure 2.

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[5] This transmission-planning information should help market participants understand how the actions that they might take (e.g., build a new generating unit or implement a voluntary demand exchange) affect their transmission costs.

[6] See Appendix 1 for a description of one structural pricing program that Energy and Environmental Economics, Inc. implemented in British Columbia, Canada.

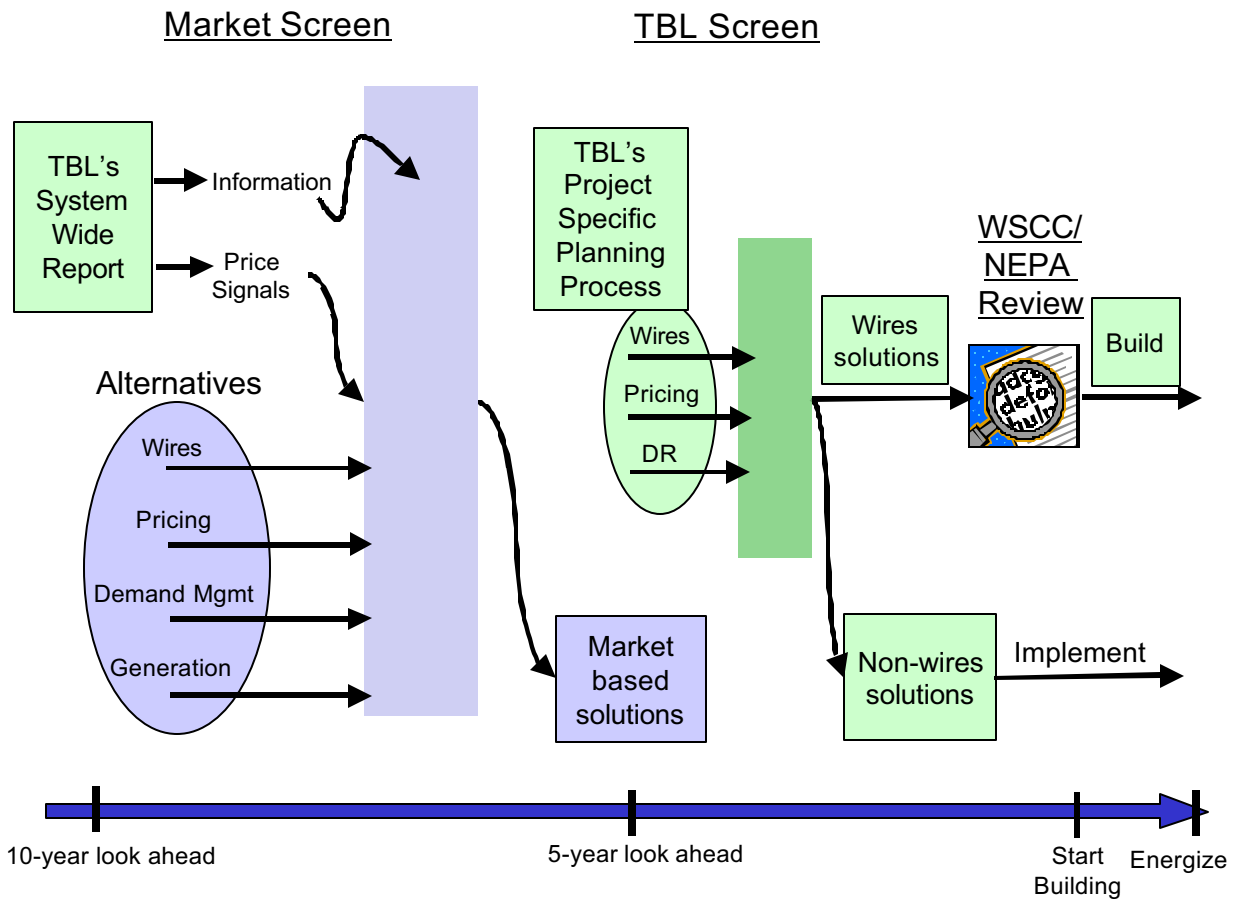

Figure 2: The Multiple Screening Process

1.3. Project-Specific Planning Process

In addition to the on-going proactive work in the longer-term planning horizon, we recommend that TBL supplement its existing project-specific planning process. In particular, TBL should develop the capability to screen transmission projects against the costs of strategically placed and operated generation resources and other nonwires solutions. Initially BPA would screen larger projects (e.g., more than $10 million in capital investment), and progressively include smaller projects as experience is gained. This supplemental task would require modifications to the current planning process that would:

1) Improve load forecasts for the biennial report and the project-specific planning process. The current process for forecasting the capacity requirements for the transmission system combines a BPA forecast for full-requirement customers (municipalities, PUDs, REAs, and cooperatives) with a growth projection provided by seven investor-owned utilities, and 14 public utilities with significant generation. The BPA forecast covers only 25% of the winter peak load, with forecasts provided by others making up the remaining 75%. Since these load forecasts drive the need for investments, their accuracy and consistency are extremely important. The recommended changes to the process include:

a) Remove the incentive for the utilities that submit their forecast to over-estimate their peak load requirement.[7] A comparison of past forecasts and loads could determine if there is a systematic bias in the forecasts that are submitted.

b) Analyze a range of high, base-case, and low peak loads in the forecasting process. This will allow for a meaningful analysis of alternative investment approaches. If a low forecast has a reasonable probability of occurring, a smaller, incremental investment approach may be cost-effective because it allows TBL to install capacity and observe the loads before committing to a large project.[8]

c) While transmission problems may be identified based on annual or seasonal peaks, as proscribed in NERC and WSCC criteria, analysis of nonwires alternatives should be based on hourly load-duration curves, rather than only on the annual peak. The load duration curve is important when evaluating alternative solutions because TBL will need to know when and how often generation or load reduction is required to solve the capacity problem. This is not typically part of traditional transmission planning since transmission lines provide capacity continuously once constructed.

2) Quantify the cost and reliability consequences of not building suggested projects. An important question in any review of a transmission plan is what will happen if the project is not built. The TBL planning process should address this by explicitly quantifying the degradation in reliability of the system, the number and types of customers that would be affected, and the potential economic impact on customers. Many projects are built to comply with the WSCC planning criteria. The quantification of the 'do-nothing' case should describe how far short a system will be of these criteria without the project. Depending on the type of customers, there are a number of ways to estimate the economic impact of not building a project. These include estimating the expected unserved energy (EUE) and value of service (VOS), and estimates of market power impacts on prices, and lost sales opportunities for generators[9].

3) Evaluate alternatives such as demand management, distributed generation (DG), interruptible/curtailable rates, and transmission pricing solutions to transmission problems. Are any nonwires alternatives more cost-effective than the proposed transmission project? In the project-specific planning process, we recommend that TBL perform a high-level

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[7] The incentive to submit high forecasts is caused by the payment structure for transmission. The payments are not linked to the load forecasts, but are based on actual metered usage. Therefore, a high forecast ensures excess capacity at no additional cost.

[8] On the other hand, there are large economies of scale in transmission construction that argue for overbuilding ahead of need.

[9] For further discussion on EUE and VOS refer to 'How Much Do Electric Customers Want to Pay for Reliability? New Evidence on an Old Controversy', Energy Systems and Policy, Volume 15, pp. 145-159 1991 by Woo, C.K, Pupp, R.L, Flaim, T. and Mango, R. and 'Costs of Service Disruptions to Electricity Consumers', Energy Vol. 17, No. 2, pp. 109-126, 1992 by Woo, C.K., and Pupp, R.L..

economic screening of a wide range of alternative solutions. This screening approach would start with a simple evaluation using optimistic assumptions about the cost-effectiveness of these nonwires options to allow TBL to look at as wide a set of alternatives as possible. For those measures that have some potential, more time can be devoted to refining the input assumptions and making a more detailed analysis of potential program designs. Section 2 presents an example of an easily implementable high-level economic screen for four different types of nonwires options.

4) Evaluate potential market impacts of new transmission investments. Beyond improving the reliability of the transmission system, many projects are built to allow increased trade and generation interconnection, and to improve market efficiency. In order to describe the complete benefits of a new transmission project, particularly those that are proposed for market reasons, TBL should estimate the effect on the regional energy markets. For example, adding new capacity into an existing load pocket could eliminate the need for standing contracts (such as Reliability Must Run contracts) with generators inside the load pocket and provide regional economic benefits. Because of the market power issues seen in the last few years, several jurisdictions including the California ISO and ISO New England have begun to look at transmission investments with respect to mitigation of market power and reduction of market prices.

5) Implement the modifications suggested by BPA to the scoring and selection of preferred transmission plans. TBL's current investment decision process (called "Matrix") ranks and prioritizes projects for consideration in the capital budgeting process. A number of improvements have been suggested that will significantly improve this process. The most important improvements are developing more specific financial and performance metrics to compare plans, and ranking projects with other projects in the same general category. This approach will make the budgeting process easier to explain since explicit criteria have been used to select projects for funding. Some of the other suggested modifications will provide additional criteria such as EUE, VOS, and impact on market power to supplement existing financial and reliability metrics that are already evaluated in the existing process.

Collectively, these new functions fit directly into the existing process as shown in Figure 3.

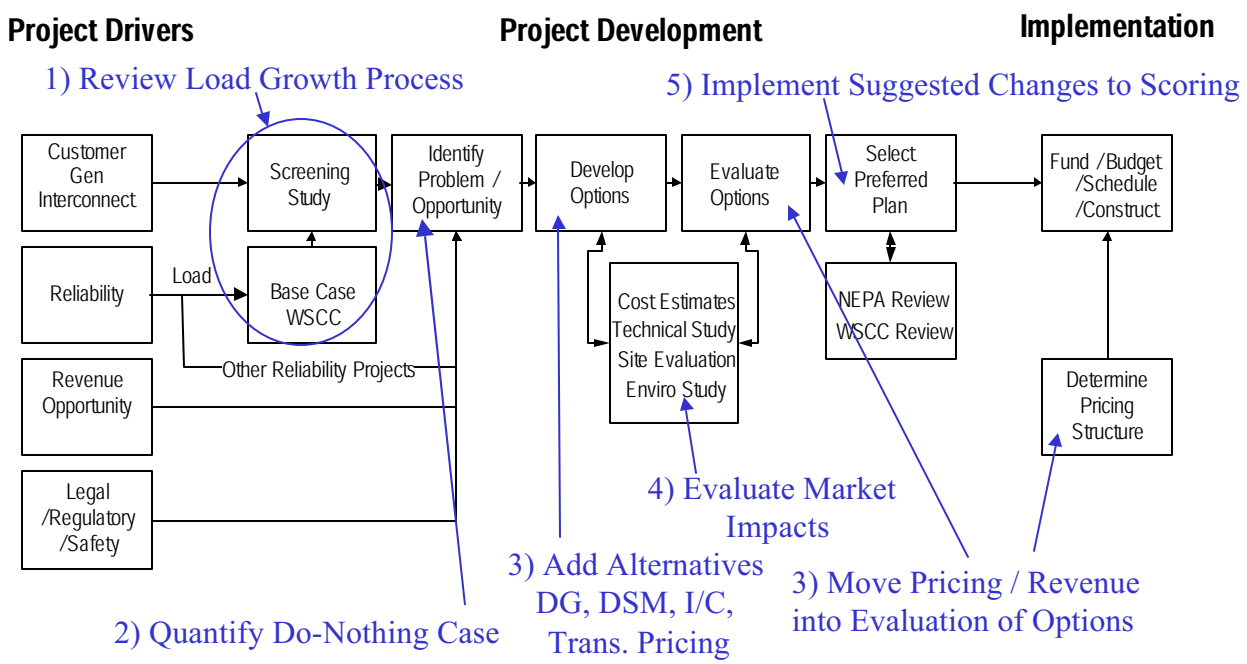


Figure 3: Suggested Modification to TBL's Planning Process

If market constraints or reliability problems are serious, persistent, and do not have a market solution, TBL's on-going project-specific planning process will identify suitable transmission projects to correct the problem. Because this initiates a centralized (rather than market) fix to the problem, the amount of accountability is now greater than if market solutions provided the fixes. TBL's recommended plan should include discussion of the following issues:

1) What is the existing transmission need?

2) Is the proposed project the lowest cost transmission investment to meet that need?

3) Is the recommendation based on realistic assumptions about the future? That is, have the various uncertainties about the input assumptions been adequately considered in assessing alternative solutions to transmission problems?

4) Based on the costs of nonwires alternatives is the plan the least cost alternative? This type of "backstop" screening requires that TBL produce a cost-effectiveness study of every large project that has the potential to be replaced by a nonwires alternative. While this may sound like an unneeded and onerous process, our experience with other utilities indicates that it will not be difficult to implement. If the long-term process is effective, most of the plans should be either the only option left or the most cost effective by the time it shows up on the project-specific planning process radar screen. Moreover, the screening process can be readily automated with relatively simple software and screening processes.

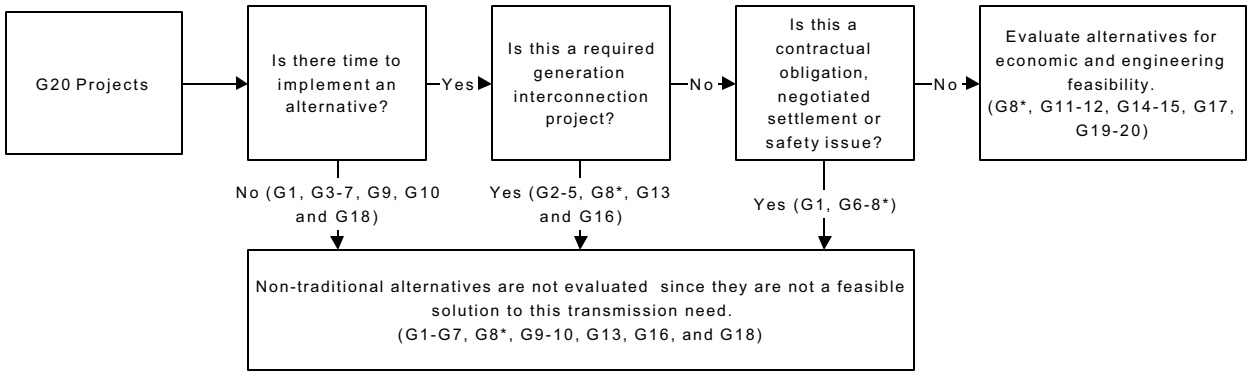
Section 2: Review of Existing Plans

2.1. Initial Screen of the G20 Projects for Evaluation of Alternatives

This section reviews the transmission projects that TBL currently has planned to estimate the potential for nonwires alternatives. Each of the G20 projects has its own particular considerations, and for some projects there has been significant engineering and economic analysis, public workshops and forums, and other work completed. The projects can generally be divided into four categories that are useful to assess whether non-traditional alternatives are a viable solution.

There are three general categories of TBL's transmission needs that non-traditional alternatives will not solve. These are: (1) problems that require an immediate solution; (2) generation interconnection: and (3) contract, negotiated settlement, or safety obligations. Each of these categories is described in more detail below, along with the list of projects for which it applies. All told, 11 of the G20 projects fall into one or more of these three categories. The remaining projects fall into the fourth category: (4) further analysis of the economic and engineering feasibility of alternatives should be conducted. The following diagram illustrates this high-level screening process.

Initial Screen of G20 Projects



* G8; The primary driver for this project is the Canadian Entitlement return, and service of loads to the Puget Sound area. If the Canadian Entitlement return is purchased within the US, non-traditional alternatives may effect this plan.

The following sections describe each of these categories in more detail.

2.1.1. Timing of the Project

Since transmission planning at TBL is an on-going effort, there are a number of projects whose decision date is very near, and it would be impossible to replace the project with a non-

traditional alternative and not violate WSCC reliability criteria. The timing of the decision dates, and in-service dates is included in Table 1 below.

Table 1: TBL Transmission Projects - Updated Schedule (9/26/01)[a]

	Project	Type	Decision	Energization
G1	Kangley - Echo Lake 500 kV line	EIS	Jan-02	Nov-02
G2	Schultz - Black Rock 500 kV line	EIS	Jan-03	Oct-04
G3	McNary - John Day 500 kV line	EIS	Sep-02	Oct-04
G4	Lo Monumental – Starbuck 500 kV line	EIS	Sep-02	Oct-04
G5	Smiths Harbor - McNary 500 kV line	EIS	Sep-02	Oct-04
G6	Schultz series capacitors	CX	Oct-01	Nov-03
G7	Celilo Modernization	CX	Oct-01	Dec-02
G8	Monroe - Echo Lake 500 kV line	EIS	Oct-03	Oct-05
G9	Bell – Coulee 500 kV line	EIS	Nov-02	Oct-04
G10	Pearl Transformer	CX	Apr-02	Oct-03
G11	South Seattle Transformer	CX	TBD	Oct-05
G12	Shelton Transformer and line addition	EIS	Oct-03	Oct-05
G13	Paul – Troutdale 500 kV line	EIS	Oct-04	Apr-06
G14	Hanford – Ostrander loop-in	CX	Apr-04	Apr-06
G15	Libby – Bonners Ferry rebuild	EIS	Oct-04	Oct-06
G16	McNary tap to Ashe - Marion 500 kV line	EIS	Oct-03	Apr-06
G17	Little Goose – Starbuck 500 kV line	EIS	Oct-04	Oct-06
G18	Hatwai – Lolo 230 kV line	EIS	Oct-02	Apr-05
G19	McNary – Brownlee 230 kV line	EIS	Oct-03	Jun-05
G20	Libby – Bell 230 kV line	EIS	Oct-04	Oct-06

[a]The shaded projects have decision dates before January 2003.

As a practical matter, those projects that must be committed to by the end of 2002 to avoid reliability problems are so near-term that it is not feasible to replace them with nonwires alternatives. The decision date is the critical date since even though it is possible to cancel at any point up until the project is in service, there will be a significant amount of money and staff time invested in the project.

The projects that fall into the near-term are G1, G3-7, G9-10, and G18. The rest are far enough in the future that there is time to consider nonwires approaches.

Generation Interconnection and Transmission Service

There is a second group of projects that are necessary to provide transmission network capacity to new generation that is being interconnected at customer request. These types of projects will not generally be able to be avoided by load reduction or distributed generation, since TBL must have enough capacity for these customers once they decide to interconnect and request long-term transmission service. These generation interconnection projects include G2-G5, G8 (although G8 is primarily driven by other factors), G13, and G16.

Negotiated Settlement, Contractual Obligation, Safety

Finally, a third category of transmission investment is necessary because of prior contractual obligations, such as the Canadian Entitlement return, negotiated settlement, or safety. A good example of a negotiated settlement project is G7. This project would upgrade the north terminal of the HVDC line to Southern California and is the result of extensive public collaboration.

The Canadian Entitlement return is the commitment made by the US government as part of the Columbia River Treaty of 1964 to return power to Canada. This agreement was made when Canada built three large storage dams that increase the output of dams in the US. The return of power back to Canada began in 1998, and will increase through 2003. The Canadians may decide to take delivery of the power within the US, thereby reducing the need to deliver power to the Canadian boarder, but under the current agreement a number of new lines would be required. The projects that are at least in part influenced by the Canadian Entitlement return are G1, G6, and G8. Because of its timing, the G8 project is the only one of these that might be avoidable by a future agreement with Canada and/or non-traditional alternatives.

Economic / Reliability

After examining the G20 projects using the three considerations described above the remaining projects have potential for non-traditional alternatives, no explicit legal requirement to build if a reliable alternative exists, and time to complete the analysis before a decision is made on the final project. The candidate projects include G8, G11-G12, G14-15, and G17-G20 (9 of the 20 projects).

2.2. Economic Screening of G12 Olympic Peninsula Additions

In this section we present an illustrative analysis of the avoided costs that appropriately located load reduction or generation could provide to the BPA transmission system. The example is based on the G12 transmission investments for the Olympic Peninsula that was placed in the economic screening 'bucket' from the previous analysis. While we have incorporated the available data as much as possible, this is an illustrative example only and we have simplified the data to better explain the underlying screening process.

The basic calculation behind the economic screening is the change in BPA-TBL revenue requirement that can be achieved by the deferral of a wires investment. If a deferral of a wires

investment lowers[10] the revenue requirement then this potential "savings" can be used to "buy" a nonwires alternative. The cost of the alternative should not exceed the savings achieved from the deferral of the wires project.[11] Estimation of avoided transmission costs would be performed by TBL and included in its 10-year planning document (and perhaps implemented with a new pricing mechanism).

The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution. The backstop screening analysis of nonwires alternatives to a transmission investment, proposed for TBL's project-specific planning process and discussed in Section 1, should also include the avoided generation capacity and energy costs, and distribution avoided costs. While TBL could pay no more than its avoided transmission costs for a nonwires solution, an economic screen needs to incorporate all avoided costs that can be achieved by a nonwires project. [12]

This section focuses on the calculation of the transmission avoided cost component, however the method is similar for the other components of avoided cost[13].

2.2.1. Transmission Avoided Costs

Step 1: Estimate the revenue requirement and timing of the planned transmission investment.

Table 2 shows the revenue requirements for the planned G12 project. This project increases capacity for service to the Olympic Peninsula and is comprised of a conductor upgrade in 2005 and capacitor additions in each of the years 2011 through 2015. The costs are shown at revenue requirement levels (direct investment dollars have been scaled up to account for administrative and general costs, debt repayment, tax effects, and operations and maintenance expenses) so that the economic savings to the BPA ratebase can be estimated.[14] The revenue-requirement amounts shown in column C for the capacitors in years 2011 through 2014 are in 2001 dollars. These are

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[10] A deferral of a wires investment that resulted in increased O&M costs could potentially increase the revenue requirement.

[11] All other things being equal, e.g., reliability, environmental externalities, etc.

[12] For example, a load reduction program planned in a specific area to reduce loading on a transmission line would also reduce loads on the local distribution system and generation market. If the total incentive paid to the customer were based on transmission avoided costs it may not be attractive to the customer nor would the payment reflect all of the benefits of the load reduction. However, by adding any offset wholesale power purchases, and adding local distribution company incentives based on distribution avoided costs, the backstop screen may find the program cost-effective.

[13] For more detail, see *Costing Methodology for Electric Distribution System Planning*, prepared by E3 and Fred Gordon of Pacific Energy Associates for the Energy Foundation.

[14] The cost numbers listed here include an increase of 30% to account for indirect costs and overhead (provided by BPA), and an additional increase of 10% for allowance of funds used during construction.

inflated using the assumed annual inflation rate of 2.7% to get the nominal revenue requirements dollars shown in column E.

The approach described here has been used in dozens of case studies including those referenced earlier. This method of calculating the long run incremental costs is also referred to as the 'differential revenue requirement' method because it is based on the difference in revenue requirements before and after deferral of the transmission project.

Table 2: Revenue Requirement of Planned Expenditures

A	B	C	D	E
Year	Investment	Constant Base Year Dollars ($1000s)	Base Year	Revenue Requirement in Nominal Dollars ($1000s)
Investment data from BPA				
2005	G12 project			40,908
2011	capacitors	1,300	2001	1,697
2012	capacitors	1,300	2001	1,743
2013	capacitors	1,300	2001	1,790
2014	capacitors	1,300	2001	1,838

Step 2: Evaluate the load reduction on the transmission path that would be required to delay the project.

Table 3 shows the load growth forecast in the area affected by G12. The project has been planned to meet the expected load in the winter of 2004/2005, so if the load is kept at or below 2004/2005 levels the transmission project can be delayed. Column B gives the forecasted load projection. The highlighted numbers (2004 to 2009) in column B were provided by TBL, and the remaining peak load numbers were projected by E3 using an assumption of 2% growth rate. The load growth per year is shown in column C.

Table 3: Load Growth Estimate for G12

A	*B*	*C*
Year	Peak Load (MW) Escalated 2%	Total Growth (MW) *Col B - Col*
2002	1,367	
2003	1,394	27.34
2004	1,422	27.88
2005	1,451	29.00
2006	1,480	29.00
2007	1,509	29.00
2008	1,540	31.00
2009	1,571	31.00
2010	1,602	31.42
2011	1,634	32.05
2012	1,667	32.69
2013	1,701	33.34
2014	1,735	34.01
2015	1,769	34.69
2016	1,805	35.38
2017	1,841	36.09
2018	1,877	36.81
2019	1,915	37.55
2020	1,953	38.30
2021	1,992	39.07
2022	2,032	39.85
2023	2,073	40.65
2024	2,114	41.46
2025	2,157	42.29
2026	2,200	43.13
2027	2,244	44.00
2028	2,289	44.88

Step 3: Calculate the change in revenue requirement per kW of load reduction based on the deferral value.

Table 4 calculates the reduction in revenue requirement for the G12 project due to a load reduction.[15] Column A shows the revenue requirement of the expenditures (from Table 2). Column B is the projected annual growth from the load forecast in Table 3. Column C shows the assumed amount of load reduction, which has been set to equal the growth from 2004/5 to 2005/6, i.e. one year of load growth.

[15] This load reduction could be due to distributed generation, curtailable load, DSM or other strategy.

In this example, we assumed a sustained reduction of 29 MW of load through the planning horizon, which would be achievable with a long-life measure such as installation of wall and ceiling insulation in a building that is expected to remain in use for many years. However, only load reductions in years with expenditures affect the revenue requirement, i.e., the 29-MW load reduction will delay the $41 million investment in 2005 until 2006, with a deferral value of over $2 million, but there are no further expenditures planned until 2011 so the deferral value is zero in 2006-2010. If we were evaluating a short–term load reduction measure, such as a three-year curtailable rate option, then this measure would not be credited with the deferral values in years 2011 through 2014.

The assumption on the amount of load reduction is important but subtle. We are estimating the incremental value of load reduction on the constrained path for a **meaningful** increment of load[16]. Column D shows the deferral length in years achieved by the load reductions in column C and this value varies by year depending on the load growth that year. Column E shows the deferral value of the load reduction for each year. The deferral value is calculated as the difference in the present value of revenue requirement before and after the investment is deferred. [17]

This method for calculating the deferral value is based on the concept that the value of a load change is equal to the difference between the present value of the original investment plan and the present value of the deferred plan. [18] A deferred investment is increased by the inflation rate, but the costs are discounted an additional year. Since the discount rate is higher than the inflation rate, this results in a net savings:

Deferral Value = Nominal Cost in Year(i) × (1 – ((1+*Inflation Rate*)/(1+*Discount Rate*))^Δt)

Where Δt is the deferral length in years.

For example, the 29 MW of load reduction prior to 2005 results in a savings of $2.364 million dollars of revenue requirement. Column F divides this total value by the amount of load reduction required to get the value per kW of load reduction, giving a marginal cost of $81.53/kW in 2005. This means that each kW of the 29 MW of total reduction in 2005 is worth $81.53/kW[19] because of the value of deferring the expenditures in that year.

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[16] For systems that have a radial configuration, the amount of load reduction on the constrained path will be the same as the total resource that is implemented (adjusted for losses). In network systems, flow distribution factors can be used to estimate load reduction achieved on the constrained path from a reduction at a particular point on the system.

[17] The inflation rate and weighted average cost of capital (WACC) used in the calculation of Column E are 2.7% and 9%, respectively.

[18] See Area Specific Marginal Costing for Electric Utilities: "A Case Study of Transmission and Distribution Costs", R. Orans Ph.D. Dissertation, 1989.

[19] Note that the $81.53/kW value only holds if the full 29 MW of load reduction can be achieved.

Table 4: Calculation of Transmission Deferral Value

	A	B	C	D	E	F
Year	Scaled Nominal Cost ($000)	Load Growth (MW)	Load Reduction (MW)	Deferral Length (yrs)	Deferral Value ($000)	Marginal Cost ($/kW)
	(see prior table)			*(Col C / Col B)*	*(A * (1-((1+inflation)/(1+WACC))^D))*	*(Col E / Col D)*
2003	0	27.3	29.0	1.06	0	0.00
2004	0	27.9	29.0	1.04	0	0.00
2005	40,908	29.0	29.0	1.00	2,364	81.53
2006	0	29.0	29.0	1.00	0	0.00
2007	0	29.0	29.0	1.00	0	0.00
2008	0	31.0	29.0	0.94	0	0.00
2009	0	31.0	29.0	0.94	0	0.00
2010	0	31.4	29.0	0.92	0	0.00
2011	1,697	32.0	29.0	0.90	89	3.07
2012	1,743	32.7	29.0	0.89	90	3.09
2013	1,790	33.3	29.0	0.87	90	3.11
2014	1,838	34.0	29.0	0.85	91	3.14
2015	0	34.7	29.0	0.84	0	0.00
2016	0	35.4	29.0	0.82	0	0.00
2017	0	36.1	29.0	0.80	0	0.00
2018	0	36.8	29.0	0.79	0	0.00
2019	0	37.5	29.0	0.77	0	0.00
2020	0	38.3	29.0	0.76	0	0.00
2021	0	39.1	29.0	0.74	0	0.00
2022	0	39.8	29.0	0.73	0	0.00
2023	0	40.6	29.0	0.71	0	0.00
2024	0	41.5	29.0	0.70	0	0.00
2025	0	42.3	29.0	0.69	0	0.00
2026	0	43.1	29.0	0.67	0	0.00
2027	0	44.0	29.0	0.66	0	0.00
2028	0	44.9	29.0	0.65	0	0.00

Step 4: Calculate the total transmission avoided cost.

Table 5 shows the calculation of the total avoided costs of deferral of the G12 project over the life of the load reduction that achieves the deferral. Column B shows the marginal cost in $/kW from Table 4. Columns C, D, E and F show the avoided costs for load reduction measures that last for 3, 5, 10 and 15 years respectively. Row 14 calculates the net present value of the avoided cost stream, which is equivalent to the total avoided cost per kW over the horizon of 3, 5, 10 and 15 years respectively. For example, a load reduction of 29 MW for 3 years is worth $68.62 per kW, which is the sum of the marginal values in years 2003, 2004 and 2005 discounted by the weighted average cost of capital (WACC). The value for a 5-year reduction is the same as the 3-year reduction because there are no further avoided costs in the years 2006 and 2007. The

longer-term measures of 10 and 15 years have higher values as they are capturing the value of avoided cost in years 2011 through 2014.

Table 5: Calculation of the Total Marginal Cost Over the Life of the Load Reduction

	A	B	C	D	E	F	G
Row			Measure Duration in Years				
		Marginal Cost ($Nominal/kW)					
1	Year	*From Col H*	3	5	10	15	Comment
2	2003	0.00	0.00	0.00	0.00	0.00	*Marginal Costs included match the*
3	2004	0.00	0.00	0.00	0.00	0.00	*duration of the measure indicated in*
4	2005	81.53	81.53	81.53	81.53	81.53	*Row 1*
5	2006	0.00		0.00	0.00	0.00	
6	2007	0.00		0.00	0.00	0.00	
7	2008	0.00			0.00	0.00	
8	2009	0.00			0.00	0.00	
9	2010	0.00			0.00	0.00	
10	2011	3.07			3.07	3.07	
11	2012	3.09			3.09	3.09	
12	2013	3.11				3.11	
13	2014	3.14				3.14	
14	Total Marginal Cost (NPV$/kW)		$68.62	$68.62	$71.59	$74.12	*NPV(WACC,Rows 2 to 11)*(1+WACC)*

These calculations suggest that TBL could pay up to $74.12/kW for a program that cut demand by 29 MW in 2003 and maintained that reduction for 15 years. If TBL can acquire such load reductions for a lower price, it should do so and defer the transmission project. If not, it should go ahead and build the G12 project. Programs lasting 3, 5, or 10 years should be evaluated on the same principle.

2.2.2. Application to Screening Non-Wires Alternatives

After calculating the avoided costs achievable by a load reduction, TBL should perform an economic screening analysis on a wide-range of nonwires alternatives to the transmission project. This screening process will help determine if a program to encourage nonwires alternatives warrants consideration, or if the economics make such projects clearly non cost-effective. Using optimistic assumptions for the nonwires alternatives, measures that are not cost-effective in this broad level screen will not warrant closer examination in a detailed screening study. The goal of the screening level analysis is to allow consideration of a broad set of options without requiring intensive analysis. For options that look promising after a screening study has been completed, a more refined analysis can be conducted. Appendix 1 provides an example of this screening analysis, calculating the lifecycle costs and benefits of a number of different alternatives including demand side management (DSM), DG, Fuel Switching, and Curtailable Programs in comparison to the G12 transmission project.

Benefit/Cost Perspectives

Suggesting that a measure is "cost-effective" immediately raises the question, "cost effective to whom?" The cost-effectiveness of a potential measure is evaluated from a number of different perspectives, which are described briefly below.

Ratepayer Impact Measure (RIM) - Transmission Company

This benefit/cost test measures the impacts on TBL's rates. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments paid by TBL to the providers of the nonwires solution(s) to the transmission problem, TBL's administrative costs and TBL's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that TBL charges to meet its revenue requirement. Measures that significantly reduce sales, such as conservation, generally appear not cost-effective from the RIM perspective.

Utility Cost Test - Transmission Company

This test measures the impacts on TBL's revenue requirement. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments and administrative costs. If the program benefit/cost ratio is less than one, the program will increase the revenue requirement. This test is different than the RIM test because the lost sales due to any measures that reduce TBL sales do not affect the revenue requirement; this depends, of course, on the transmission rate design.

Total Resource Cost Test (TRC)

The TRC test measures the costs and benefits from a broader perspective and includes all of the direct cash costs due to the measure. The benefits include the transmission, distribution, generation capacity and energy avoided costs, and the costs included are the lifecycle costs of the measure and administrative costs. Transfers such as incentive payments between TBL and its customers, as well as bill savings are not included from this perspective since the net cost between TBL and customers is zero.

Societal Cost Test

The societal cost test includes the broadest set of costs and benefits due to a measure. In addition to the direct cash costs accounted for in the TRC test, any environmental externalities such as reduced air emissions are included as a benefit.

Participant Cost Test

The participant cost test measures the lifecycle net benefits for the participant. The participant is the customer that is installing the DSM, curtailing their load, or who owns the DG. The benefits included for this test are the incentives paid to the customer and the customer's bill savings due to the measure, and the costs included are the life-cycle costs to the participant of the measure. This cost test is a good indicator of how acceptable a program will be to a customer.

Each of these tests has value to some market participants. An interesting, but not yet resolved issue, concerns the appropriate tests to use in RTO-dominated competitive wholesale electricity markets.

Program Design Issues

The value of load reduction will be the economic basis of any incentives that TBL would use to encourage alternative solutions in the market place. The design of the program will depend on the type of alternative to the transmission project, and will have the following considerations in mind;

- Payments made by TBL for the program should reflect the value of load reduction with the objective of minimizing overall transmission costs for TBL customers.
- Level and timing of payments made by TBL should reflect TBL's confidence that the required level of load reduction will be achieved.
- Programs are designed to attract participants.

Incentive Payments

The transmission-avoided cost based on revenue requirement savings as calculated in Section 2.2.1 represents the total value of load reduction or generation. An assessment must be made on how to share these benefits between the participants and non-participants in the program. If the entire avoided costs are paid to the participants (for example to get a higher penetration level) then the revenue requirement remains unchanged, and transmission users in general do not share any of the benefits of the deferral. While paying the maximum incentive may maximize uptake of alternative solutions, the objective of the program is to minimize transmission costs. Therefore TBL wants to pay the lowest incentive that is required to induce an alternative solution. The typical starting point for this analysis is an incentive level set at 50% of the avoided cost, which represents an equal sharing between participants and non-participants.

Locational Nature of the Avoided Costs

The example shown in this section calculates only the transmission avoided costs of a specific investment in the G12 Olympic Peninsula Additions. Therefore, the value is only meaningful for load reductions or generation that reduce loads on the constrained path that is the target of the load reduction.

Required Amount of Load Reduction

This example is based on an incremental amount (29 MW) of load reduction. Investments are built to meet the forecasted peak loads, so typically a deferral is only meaningful if it is in one-year steps. For example, rather than an in-service date of fall 2005, the project is moved to an in-service date of Fall 2006. Therefore, if less than the amount required for a one year deferral is achieved, and the project must still be energized according to the original schedule, and there is no deferral benefit to the load reduction.

It is questionable if a project delay of less than a year has any meaningful value. Experience shows that projects are almost always scheduled to be energized in the season prior to the forecasted peak, which for most of BPA is the winter season (hence the schedule to energize in the fall). If the load reduction falls short of what is required to lower the peak load for that winter then the project still needs to be energized in the fall. Energizing in the spring will be too late, if TBL has gone through the winter it might as well wait until the following fall to energize.

Appendix A

Section 3: Implementation of Planning Process

3.1. Long-Term Transmission Planning

TBL can take the lead in developing a long-term transmission plan, but both development and implementation of the plan should be a regional effort involving all interested players. The options open to TBL cover a wide range of possibilities. Ultimately, the path chosen should be done in concert with other Northwest interests.

At one end of the spectrum, TBL could simply publish information about the transmission grid today and the expected conditions in the future. Developing this option would require TBL to identify the kinds of information about the grid that would be useful to market participants. At the other end of the spectrum, TBL could actually run demand-side programs and build generating units to solve transmission problems. This second option seems extremely unlikely because it is so antithetical to the creation, design, and operation of competitive wholesale markets and, therefore, will not be discussed further. However, TBL could achieve the objective of solving transmission problems at least cost in other ways, for example, by issuing RFPs for nonwires and merchant-transmission solutions to transmission problems.

From the spectrum discussed above, TBL should develop the details necessary to implement two options: 1) provision of information useful to market participants; and 2) acquisition from the market of least-cost solutions to transmission problems.

For the first option, TBL should identify the specific data elements and forms of presentation needed by generating companies, power marketers and brokers, load-serving entities, transmission owners, representatives of consumer and environmental groups to make informed decisions on generation and demand-management programs. The range of information TBL could provide encompasses simple maps showing the desirable and undesirable locations for new generation from the perspective of the transmission system to detailed results from load-flow studies (voltages, real- and reactive-power flows, and phase angles) and real-time operating data.

For the second option, TBL should review the experience that other utilities and ISOs have had with the acquisition of nonwires solutions to transmission problems. For example, all the existing U.S. ISOs operate demand-management programs intended to provide reliability resources and to reduce wholesale-power costs. This review will form the basis of TBL's decision on whether and, if so, how to proceed with potential acquisition from market participants of transmission solutions.

3.1.1. Recommendation.

TBL can be the catalyst that brings together regional decision-makers to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. Recommended steps include:

1. TBL should produce a long-term view of the transmission system that includes expected congestion points, and the associated long-run differential costs of delivering power to

various points on the grid. At this stage, TBL could raise the idea and the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into a detailed discussion of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate problem areas identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost-effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design. In order to stimulate ideas among stakeholders and provide for more productive workshops, industry professionals experienced with the economics and feasibility of wires and nonwires options should be invited to participate.

5. TBL will have a number of options available to it at this point, as follows:

    a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the short-term screening process proposed herein. As suggested in Figure 2, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

    b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

    c. It may decide that locational and time sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

    d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

    e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

3.2. Project-Specific Screening.

We recommend taking two of the G-20 projects through the project-specific screening process described in Section 2 of this paper. Each of the projects would be put through all of the steps of the screening process in concert with TBL staff. Through this process, TBL will refine the screening process, and will determine if economic and reliable alternatives exist to delay transmission construction of either or both projects.

Because different issues arise with respect to transmission expansion driven by generation interconnection requests versus other reasons, we propose that TBL run two of the G-20 projects through the project-specific planning process (e.g., G-8 and G-12). G-8 is a project that crosses sensitive environmental areas, and the decision to construct it is far enough out to potentially benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound area.

Another good candidate is G-12. A brief example of how the marginal cost on a per kW-year basis would be calculated for G-12 is contained in Section 2.

3.3 Future Uncertainties

Finally, given all the uncertainties about the future of the electricity industry, we recommend that TBL develop, test, and deploy methods for dealing with these uncertainties in its planning and decision-making concerning new long-lived transmission projects. The focus should be both on the analytical process TBL might use to assess uncertainties and on presentation methods to aid interested stakeholders in understanding the implications of uncertainties related to load growth, fuel prices, new generation, demand management programs, industry restructuring, RTO formation, and government regulation.

Appendix A

Appendix 1: Sample Screen of Non-Traditional Alternatives

This Appendix shows how to derive the benefit/cost ratios of four nonwires alternatives to transmission projects: fuel switching, DG, DSM and interruptible/curtailable load programs. Please note that these examples are illustrative only and do not relate to any specific TBL projects.

Summary of Cost-Effectiveness

The alternatives for delaying the G12 transmission project are evaluated from each of the cost-effectiveness perspectives described in section 2.2.2. The measures evaluated include;

- Customer-owned distributed generation; generation that is not metered by BPA. This could be generation located at an end-users site, or within a local distribution utility. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Merchant plant distributed generation; generation located on BPA's transmission that injects power and is subject to the TBL transmission tariff. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Conservation DSM; based on a general mix of commercial energy conservation measures. The assumed cost is $3 million per average MW conserved (8760MWh per year).

- Fuel-switching DSM; based on switching from electric heating to natural gas heating for residential end-users. The assumed energy savings is 2500kWh per year, with a winter peak load reduction of 2kW.

- Curtailable Load; based on a three-year curtailable program. Each participant is assumed to be interrupted 30 hours per year with an incentive payment of $100/MWh.

Table 6, below, summarizes the benefit/cost ratio for each of these measures. The relationship of the benefit/cost ratios for each of the measures is typical. From the RIM perspective, any measures that significantly reduce sales such as DSM, fuel switching, or behind the meter generation are not cost-effective because of the lost sales component. The DG merchant plant and curtailable load program are cost effective from RIM because they do not result in significant revenue losses and the incentives are paid based on a percentage (approximately 50%) of the deferral value. For these two measures the RIM results are very similar to the utility cost test (UCT), since the only difference between the tests is the lost sales component. On the other hand, the customer DG bypass and fuel switching look much better from a UCT perspective than RIM.

The Total Resource Cost (TRC) test is the usual test of cost-effectiveness from a traditional least-cost planning perspective. If the TRC benefit/cost ratio is greater than one, incentive payments, public purpose charges, and other mechanisms can potentially be designed to make all other perspectives cost-effective. Fuel switching, and curtailable programs are the only cost-effective measures from the TRC perspective. The societal cost test is an extension of the TRC,

which includes additional non-cash benefits. Similar to the TRC, if public purpose charges are levied on the same group that accrue the non-tangible benefits, all perspectives can be made cost-effective if the societal cost test benefit/cost ratio is greater than one.

The participant cost test is critical because it indicates whether a measure is likely to be acceptable to the participants. If the benefit/cost ratio is lower than one, participants are worse off after having implemented the measure and therefore they are unlikely to adopt it. The fuel switching, conservation, and curtailable programs are cost-effective to the participant given the input assumptions of costs and incentive levels made to develop this example.

Table 6: Summary of Cost-Effectiveness

Benefit Cost Ratios	DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)	Residential Switch to Natural Gas Heating	Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)	1kW of Curtailable Load (Demand Exchange Program)
RIM Test Transmission Company	1.31	2.05	0.45	0.02	5.17
Utility Cost Test Transmission Company	2.05	2.05	1.85	0.02	5.17
TRC Cost Test	0.42	0.42	1.22	0.25	7.25
Societal Cost Test	0.42	0.42	1.35	0.30	7.28
Participant Cost Test	0.52	0.03	1.19	1.06	1.16

Of the five measures evaluated, only the curtailable load program is cost-effective from every perspective. The measure is clearly 'cost-effective' from the broadest definition. Other programs are less clear. For example, the fuel switching to natural gas heating is cost-effective from all but the RIM test. Under traditional least cost planning, this measure might be pursued with the loss in revenue made up with a public benefits charge assessed to all customers.

The examples for all four alternatives use the same set of basic assumptions. These assumptions are outlined in Table 7 below. The transmission lifecycle avoided costs are from row 14 of Table 5, above.

Table 7: General Assumptions

Input Variable	Value
Utility Discount Rate	9.00%
Financing Rate of Generator (DG)	12%
	Annual Value ($/yr)
Generation Capacity $/kW-yr	0
Local Distribution Company $/kW-yr	20
Energy (Mid-C) $/MWh	30
Environmental Adder $/MWh	6
Total Average Rate $/kWh	$0.0800
Transmission Average Rate $/kW-month	$2.5600

Transmission Lifecycle Avoided Cost$/kW				
Measure Life (Years)	3	5	10	15
Transmission Lifecycle Avoided Cost $/kW	$68.62	$68.62	$71.59	$74.12

The following four tables present the detailed calculations of the five cost tests for various non-traditional alternative scenarios. The first half of each table contains the inputs and intermediate calculations that are used in the calculation of the cost tests in the second half of the table. Input variables not included in Table 7 are highlighted, and calculated values are left clear. Where necessary, the derivation of the inputs is explained in parentheses, with items referenced by row numbers.

Table 8: Cost Tests of Distributed Generation

		DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)
1	DG Device	Gas Turbine Peaker	Gas Turbine Peaker
2	Utility Incentive Cost $/kW	$30.00	$30.00
3	Generator Life (Years)	10	10
	Generator Cost Assumptions		
4	Fuel Cost $/MMBtu	$5.00	$5.00
5	Heat Rate Btu/kWh	10,000	10,000
6	Fuel Cost $/kWh ($/MMBtu [4] * Heat Rate [5] / 10^6)	$0.05	$0.05
7	Capital Cost $/kW	$500.00	$500.00
8	Install Cost $/kW	$100.00	$100.00
9	Fixed O&M $/kW-yr	$10.00	$10.00
10	Variable O&M $/kWh	$0.005	$0.005
11	Annual Fuel and O&M Costs $/kW ({fuel cost [6] + var. O&M [10]} * annual load factor [14] * 8760 hrs in a yr + fixed O&M [9])	$58.18	$58.18
12	Environmental Externality Benefit? 1= yes, 2=no	0	0
	Generator Operating Assumptions		
13	Peak Period kW Savings	1.00	1.00
14	Annual Load Factor	10%	10%
15	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00	1.00
	Lifecycle Generator Costs		
16	Lifecycle Capital Cost ($/kW) (cap. cost [7] + install cost [8])	$600.00	$600.00
17	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Generator WACC)	$328.73	$328.73
18	Total Lifecycle Cost ($/kW)	$928.73	$928.73
	Per Unit Lifecycle Avoided Costs		
19	Generation Capacity $/kW	$0.00	$0.00
20	Transmission $/kW (total 10-year trans. marginal cost discounted at utility discount rate)	$71.59	$71.59
21	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90	$139.90
22	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21	$0.21
23	Energy + Environmental Adder (If Clean Generation) $/kWh (energy per unit cost [22] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.21	$0.21
	Rates and Lost Revenue		
24	Total Average Rate $/kWh	$0.0800	$0.0000
25	Transmission Average Rate $/kW-year	$2.5600	$0.0000
26	Total Electricity Revenue Loss $/year (total avg rate [24] * annual load factor [14] * 8760 hrs in a yr)	$70.08	$0.00
27	Transmission Revenue Loss $/year (trans. avg. rate [25] * monthly peak demand reduction [15] * annual load factor [14] * 12 months)	$3.07	$0.00

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	Lifecycle Avoided Costs per kW, Revenue per kW, Incentive per kW		
28	Generation Avoided Cost (gen. capacity per unit cost [19] * peak period kW savings [13])	$0.00	$0.00
29	Transmission Avoided Cost (trans. per unit cost [20] * peak period kW savings [13])	$71.59	$71.59
30	Local Distribution Company (local distr. per unit cost [21] * peak period kW savings [13])	$139.90	$139.90
31	Energy (energy per unit cost [22] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
32	Energy w/ Environment (energy & env. adder per unit cost [23] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
33	Total Electricity Revenue Loss (total annual loss [26] accruing over 10 years, discounted at utility discount rate)	$449.75	$0.00
34	Transmission Revenue Loss (total annual loss [27] accruing over 10 years, discounted at utility discount rate)	$19.72	$0.00
35	Lifecycle Incentive Payment	$30.00	$30.00
36	Lifecycle Admin Cost	$5.00	$5.00

		DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)
	RIM Test - Transmission Delivery Company		
37	Program Cost (Incentive+T Rev. Loss+Admin)	$54.72	$35.00
38	Program Benefit (T Savings)	$71.59	$71.59
39	Net Savings	$16.87	$36.59
40	BC Ratio	1.31	2.05
	Utility Cost Test - Transmission Delivery Company		
41	Program Cost (Incentive + Admin)	$35.00	$35.00
42	Program Benefit (T Savings)	$71.59	$71.59
43	Net Savings	$36.59	$36.59
44	BC Ratio	2.05	2.05
	TRC Cost Test		
45	Program Cost (DG Cost+ Admin)	$933.73	$933.73
46	Program Benefit (Gen Savings + T Savings + D Savings)	$395.33	$395.33
47	Net Savings	($538.40)	($538.40)
48	BC Ratio	0.42	0.42
	Societal Cost Test		
49	Program Cost (DG Cost + Admin)	$933.73	$933.73
50	Program Benefit (Gen Savings + T Savings + D Savings + Environment)	$395.33	$395.33
51	Net Savings	($538.40)	($538.40)
52	BC Ratio	0.42	0.42
	Participant Cost Test		
53	Program Cost (DG Costs)	$928.73	$928.73
54	Program Benefit (Incentive + Electricity Bill Reduction)	$479.75	$30.00
55	Net Savings	($448.98)	($898.73)
56	BC Ratio	0.52	0.03

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Table 9: Cost Tests of Fuel Switching

		Residential Switch to Natural Gas Heating
1	Cost of Original Device	$300.00
2	Replacement Device	$500.00
3	Utility Incentive Cost $/measure	$30.00
4	Measure Life (Years)	15
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings	2.00
6	Annual kWh/measure	2500.00
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 15-year trans. marginal cost discounted at utility discount rate)	$74.12
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 15 years, discounted at utility discount rate)	$175.72
11	Energy $/kWh ($MWh marg. cost accruing over 15 yrs discounted at utility disc. rate / 1000)	$0.26
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 15 yrs discounted at utility disc. rate} / 1000)	$0.32
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Alternative Fuel Rate ($/Replaced kWh)	$0.0500
16	Alternative Fuel Cost ($/Replaced kWh)	$0.0200
17	Alternative Fuel Bill ($/measure per year) (alt. fuel rate [15] * annual kWh/measure [6])	$125.00
18	Alternative Fuel Cost ($/measure per year) (alt. fuel cost [16] * annual kWh/measure [6])	$50.00
19	Admin Cost $/measure one time cost	$50.00
20	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$200.00
21	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30.72
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
22	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
23	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$148.24
24	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$351.45
25	Energy (energy per unit cost [11] * annual kWh/measure [6])	$658.96
26	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$790.75
27	Alternative Fuel Bill $/measure	$1.007.59
28	Alternative Fuel Cost $/measure	$403.03
29	Total Electricity Revenue Loss	$1.612.14
30	Transmission Revenue Loss	$247.62
31	Lifecycle Incentive Payment	$30.00
32	Lifecycle Admin Cost	$50.00

		Residential Switch to Natural Gas Heating
	RIM Test - Delivery and Alternative fuel Company	
33	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$327.62
34	Program Benefit (Trans Savings)	$148.24
35	Net Savings (Max. Incentive)	($179.38)
36	BC Ratio	0.45
	Utility Cost Test - Delivery	
37	Program Cost (Incentive + Admin)	$80.00
38	Program Benefit (Trans Savings)	$148.24
39	Net Savings (Max. Incentive)	$68.24
40	BC Ratio	1.85
	TRC Cost Test	
41	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
42	Program Benefit (Gen Savings + T Savings + D Savings)	$1,158.65
43	Net Savings (Max. Incentive)	$205.61
44	BC Ratio	1.22
	Societal Cost Test	
45	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
46	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$1,290.44
47	Net Savings (Max. Incentive)	$337.41
48	BC Ratio	1.35
	Participant Cost Test	
49	Program Cost (Buy Device + Alternative Fuel Bill)	$1,507.59
50		$1,792.14
	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	
51	Net Savings (Max. Incentive)	$284.55
52	BC Ratio	1.19

Table 10: Cost Tests of DSM

		Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)
1	Cost of Original Device	$2,000,000.00
2	Replacement Device	$8,000,000.00
3	Utility Incentive Cost $/measure	$3,000,000.00
4	Measure Life (Years)	10
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings (for T&D capacity savings)	1,000
6	Annual kWh/measure	8,760,000
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1,000
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 10-yr marginal cost discounted at utility discount rate)	$71.59
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90
11	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.25
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Admin Cost $/measure one time cost	$50,000.00
16	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$700,800.00
17	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30,720.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
18	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
19	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$71,590.00
20	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$139,904.94
21	Energy (energy per unit cost [11] * annual kWh/measure [6])	$1,838,350.88
22	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$2,206,021.06
23	Total Electricity Revenue Loss	$4,497,494.52
24	Transmission Revenue Loss	$197,150.44
25	Lifecycle Incentive Payment	$3,000,000.00
26	Lifecycle Admin Cost	$50,000.00

		Generic Conservation Measure (Office Lighting, Shell Retrofit. etc.)
	RIM Test - Delivery Company	
27	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$3,247,150.44
28	Program Benefit (Trans Savings)	$71,590.00
29	Net Savings (Max. Incentive)	($3,175,560.44)
30	BC Ratio	0.02
	Utility Cost Test - Delivery	
31	Program Cost (Incentive + Admin)	$3,050,000.00
32	Program Benefit (Trans Savings)	$71,590.00
33	Net Savings (Max. Incentive)	($2,978,410.00)
34	BC Ratio	0.02
	TRC Cost Test	
35	Program Cost (Measure Cost + Admin)	$8,050,000.00
36	Program Benefit (Gen Savings + T Savings + D Savings)	$2,049,845.82
37	Net Savings (Max. Incentive)	($6,000,154.18)
38	BC Ratio	0.25
	Societal Cost Test	
39	Program Cost (Measure Cost + Admin)	$8,050,000.00
40	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$2,417,516.00
41	Net Savings (Max. Incentive)	($5,632,484.00)
42	BC Ratio	0.30
	Participant Cost Test	
43	Program Cost (Buy Device)	$8,000,000.00
44	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	$8,497,494.52
45	Net Savings (Max. Incentive)	$497,494.52
46	BC Ratio	1.06

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Table 11: Cost Tests of I/C Programs

		1kW of Curtailable Load (Demand Exchange Program)
1	Customer Cost of Dropped Load ($/kWh) (Lost Productivity)	$0.15
2	Customer Cost of Dropped Load ($/kW lifecycle) ([1] accruing over 3 yrs)	$12.42
3	Utility Incentive Cost $/MWh	$100.00
4	Utility Incentive Cost $/kW lifecycle ([3] accruing over 3 yrs, discounted at utility discount rate)	$8.28
5	Measure Life (Years)	3
	Annual Demand and Energy Impacts	
6	Peak Period kW Savings (for T&D capacity savings)	1.00
7	Annual kWh/measure (Number of hours per year)	30
8	Monthly Peak Demand Reduction (kW) (for billing determinants)	0.00
9	Months in Peak Load Season for Curtailment	4
	Lifecycle Avoided Costs per kW or kWh	
10	Generation Capacity $/kW	$0.00
11	Transmission $/kW (total 3-year marginal cost discounted at utility discount rate)	$68.62
12	Local Distribution Company $/kW (local distr. marginal cost accruing over 3 years, discounted at utility discount rate)	$55.18
13	Energy $/kWh ($MWh wholesale energy cost accruing over 3 yrs discounted at utility disc. rate / 1000)	$0.08
14	Energy + Environmental Adder $/kWh (energy per unit cost [13] + {$MWh env. adder cost accruing over 3 yrs discounted at utility disc. rate} / 1000)	$0.10
	Rates, Administration Costs, and Lost Revenue	
15	Total Average Rate $/kWh	$0.0800
16	Transmission Average Rate $/kW-month	$2.5600
17	Admin Cost $/measure one time cost	$5.00
18	Total Electricity Revenue Loss $/year (total avg rate [15] * annual kWh/measure [7])	$2.40
19	Transmission Revenue Loss $/year (trans avg rate [16] * monthly peak demand reduction [8] * months in peak load season [9])	$0.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
20	Generation Avoided Cost (gen. capacity per unit cost [10] * peak period kW savings [6])	$0.00
21	Transmission Avoided Cost (trans. per unit cost [11] * peak period kW savings [6])	$68.62
22	Local Distribution Company (local distr. per unit cost [12] * peak period kW savings [6])	$55.18
23	Energy (energy per unit cost [13] * annual kWh/measure [7])	$2.48
24	Energy w/ Environment (energy & env. adder per unit cost [14] * annual kWh/measure [7])	$2.98
25	Total Electricity Revenue Loss	$6.08
26	Transmission Revenue Loss	$0.00
27	Lifecycle Incentive Payment	$8.28
28	Lifecycle Admin Cost	$5.00

		1kW of Curtailable Load (Demand Exchange Program)
	RIM Test - BPA TBL	
29	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$13.28
30	Program Benefit (Trans Savings)	$68.62
31	Net Savings (Max. Incentive)	$55.34
32	BC Ratio	5.17
	Utility Cost Test - BPA TBL	
33	Program Cost (Incentive + Admin)	$13.28
34	Program Benefit (Trans Savings)	$68.62
35	Net Savings (Max. Incentive)	$55.34
36	BC Ratio	5.17
	TRC Cost Test	
37	Program Cost (Cost of Dropped Load+ Admin)	$17.42
38	Program Benefit (Gen Savings + T Savings + D Savings)	$126.29
39	Net Savings (Max. Incentive)	$108.87
40	BC Ratio	7.25
	Societal Cost Test	
41	Program Cost (Cost of Dropped Load + Admin)	$17.42
42	Program Benefit (Gen Savings + Trans Savings + Environment)	$126.78
43	Net Savings (Max. Incentive)	$109.37
44	BC Ratio	7.28
	Participant Cost Test	
45	Program Cost (Cost of Dropped Load)	$12.42
46	Program Benefit (Incentive + Electricity Bill Reduction)	$14.35
47	Net Savings (Max. Incentive)	$1.94
48	BC Ratio	1.16

Appendix A

Expansion of TBL Transmission Planning Capabilities

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Summary of Recommendations

- Engage regional stakeholders in TBL's planning process
  - Goal is to **share information** that would lead to a more efficient region-wide system
- Biennial system-wide report
  - **Describes the expected use** of BPA's transmission facilities over the following 10 years
- Refinement of existing planning process
  - **Screen transmission projects** against the costs of various forms of suitably located and operated generation, load management, and transmission pricing

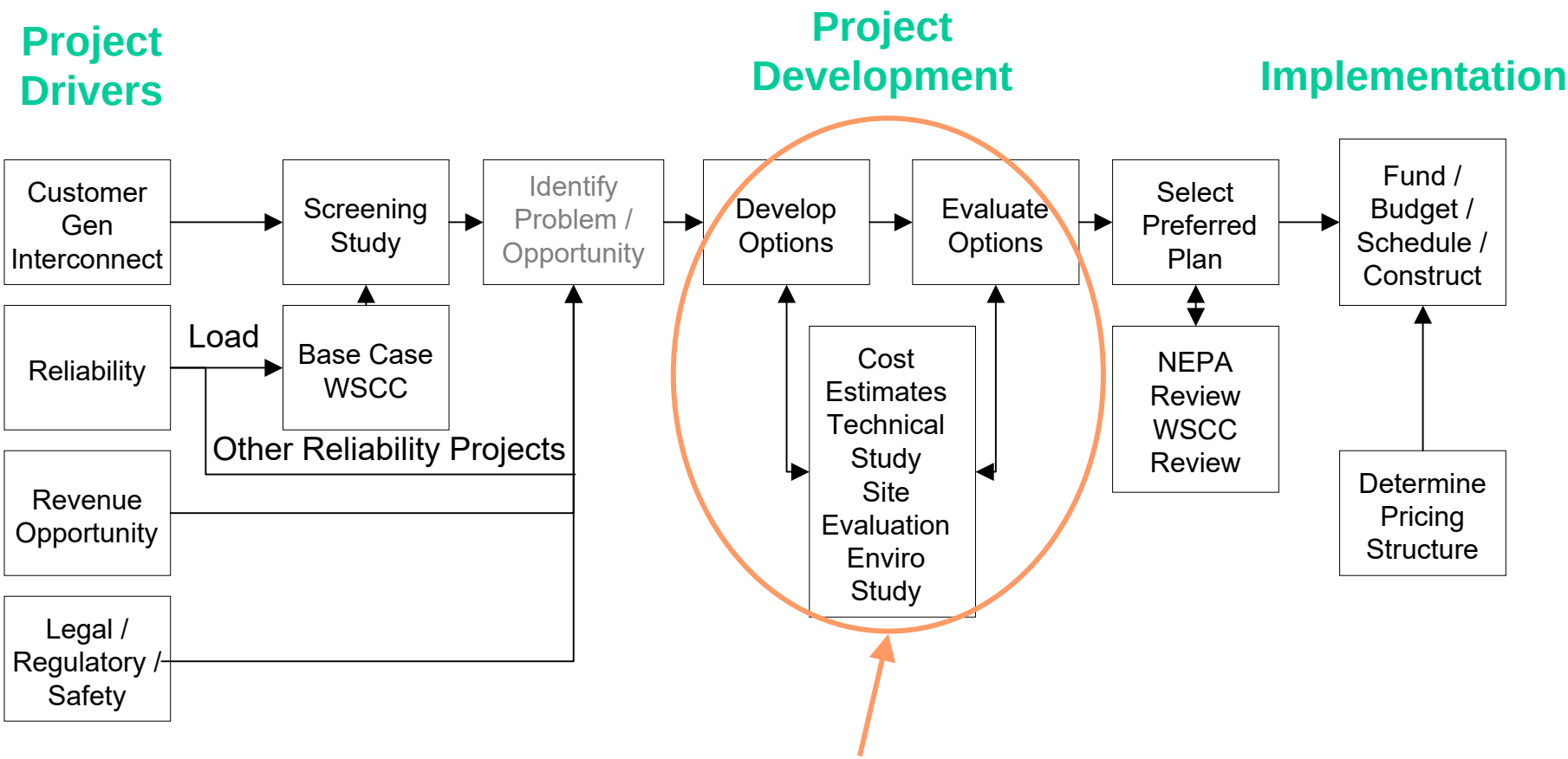
Existing TBL Planning Process

- Designed to **meet anticipated customer needs**
- **Reactive** -- driven by events external to TBL

Problems with Traditional Planning

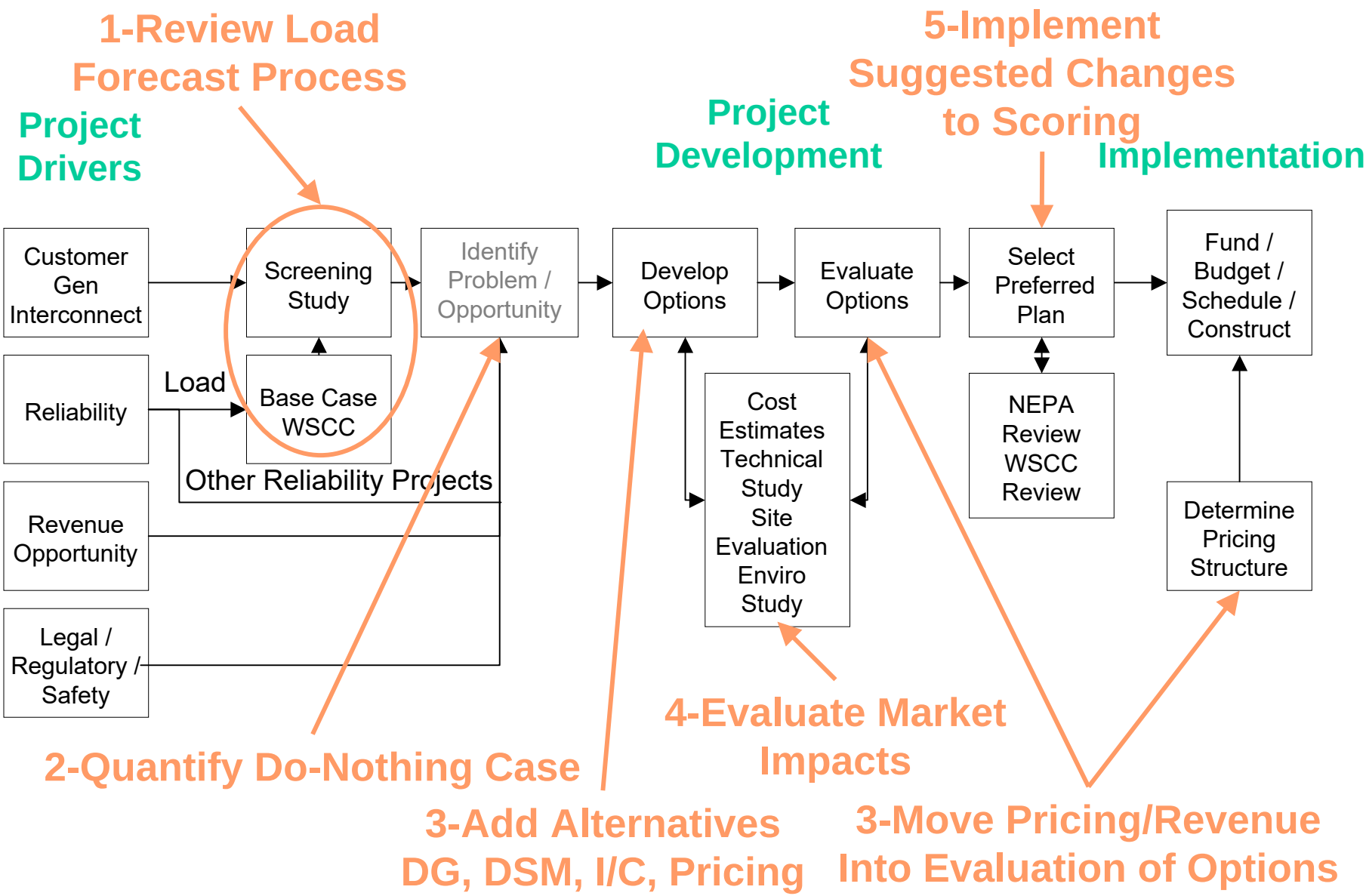
- **Reactive** -- driven by events external to TBL
- Insufficient time to consider non-wires alternatives
- Insufficient time to engage other stakeholders

Overview of Existing Process



Level of detail changes with cost and risk of projects

Suggested Modifications

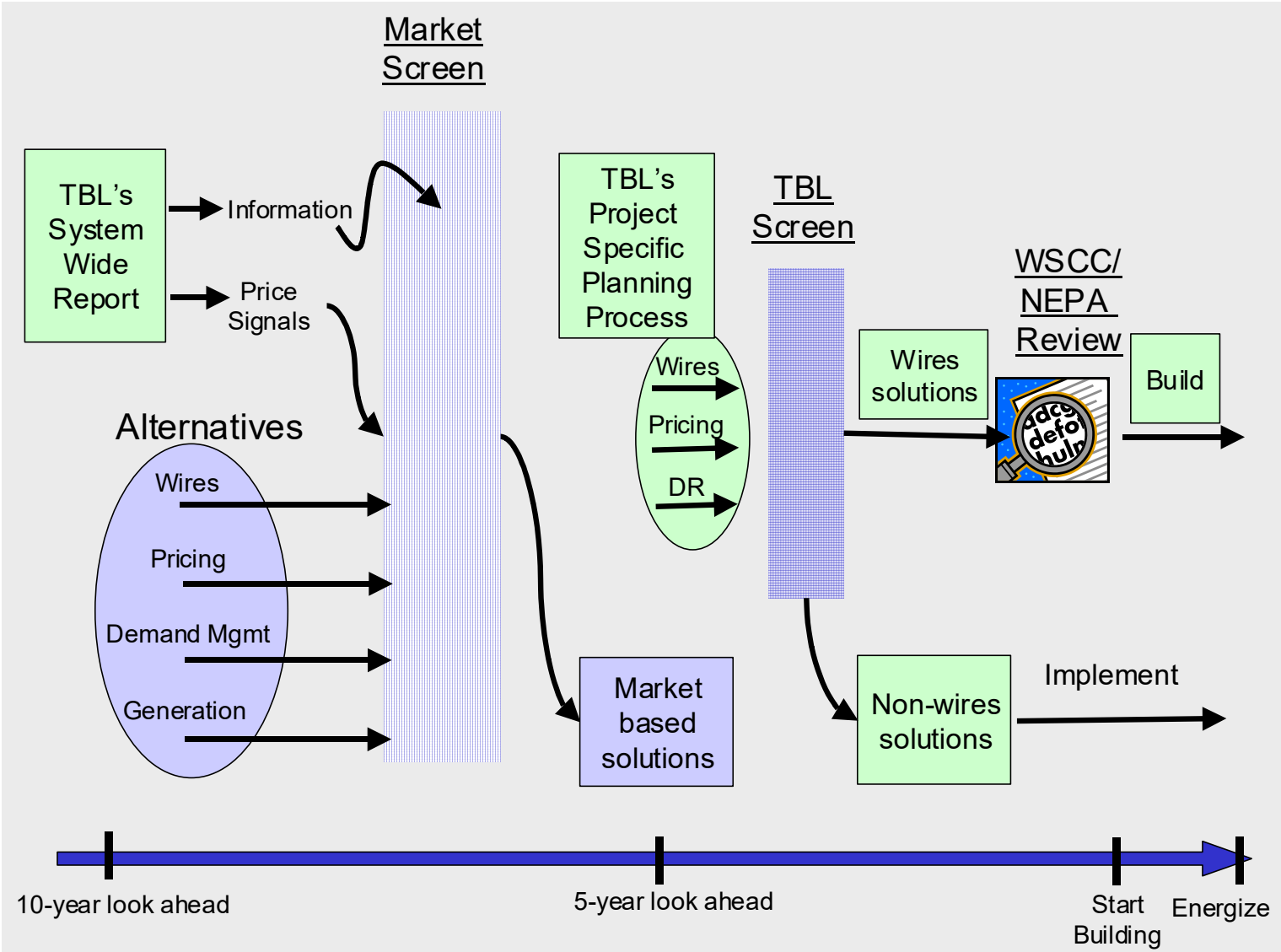


Extending the Existing Process

- A first screen to identify transmission problems that cannot be solved by non-wires alternatives.
- A second screen (for remaining transmission projects) against the costs of strategically located and operated generation, demand management, and transmission-pricing programs.

The TBL Backstop Screen

The Multiple Screening Process



Transmission Planning During Transition to Fully Functioning Markets

- Transparent planning in lieu of being able to set prices or to do least-cost planning.
- Coordination with affected parties

Engage Regional Stakeholders

Share information that will lead to more efficient region-wide system

Workshops for Stakeholders

❶ Conduct scoping workshop with interested and affected parties

❷ Discuss findings in biennial report and identify potential non-wires solutions to transmission needs identified.

❸ In second workshop ask for specific actions that can be taken by regional parties, and that would be as reliable and as cost-effective as wires upgrades.

The Vermont Statutes Online

Title 30: Public Service

Chapter 5: Powers and Duties of Department of Public Service

218c. Least cost integrated planning

§ 218c. Least cost integrated planning

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be determined with due regard to:

(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;

(B) the state's progress in meeting its greenhouse gas reduction goals; and

(C) the value of the financial risks associated with greenhouse gas emissions from various power sources.

(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies

Appendix C

with the requirements of subdivision (a)(1) of this section.

(c) [Deleted.]

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least 10 years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective nontransmission alternatives to meet

reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other nontransmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate nontransmission alternatives. The meetings shall be at separate locations within the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by

Appendix C

at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation

council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4)(A) A transmission system plan shall be revised:

(i) within nine months of a request to do so made by either the public service board or the department of public service; and

(ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained

Appendix C

otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate. (Added 1991, No. 99, § 2; amended 1999, No. 60, § 2, eff. June 1, 1999; 1999, No. 157 (Adj. Sess.), § 7; 2005, No. 61, § 9; 2007, No. 209 (Adj. Sess.), § 13.)

Appendix C

TRANSPOWER

Grid Support Contracts

Discussion Paper

November 2008

Appendix D

Contents

Appendix D

Glossary

Item	Description
3G	GRS, GEIP and GIT
Additionality	A term to describe whether the DSP called for was truly additional to whatever would have happened in the absence of the call
Aggregate	Assemble a number of DSP sources for the purpose of offering them to Transpower
APR	Annual Planning Report, a Transpower publication
AUFLS	Automatic Under-frequency Load Shedding – shedding load when the system frequency drops significantly
Block	A defined amount (MW) of DSP or non-market generation capacity, that can be called individually by Transpower
Call	A call by Transpower for delivery of DSP Deliver Provide DSP when called. The provider reduces demand or provides generation thus delivering DSP
DSP	Demand-side participation
EC	Electricity Commission
EGRs	Electricity Governance Regulations and Rules 2003
GEIP	Good electricity industry practice
GIT	Grid investment test
GRS	Grid reliability standards
GSC	Grid support contract
GUIRP	Grid upgrade investment and review process
GUP	Grid Upgrade Plan
IL	Interruptible load, being one form of Instantaneous Reserve
LF	Load forecaster: the model used by the System Operator in creating the Schedule of Dispatch Prices and Quantities (SDPQ)
LRMC	Long run marginal cost
RFI	Request for information
RFP	Request for proposals
RMA	Resource Management Act
SOO	Statement of Opportunities, an EC publication
SSF	System Security Forecast, a Transpower System Operator publication
TPM	Transmission pricing methodology, defined in Schedule F5 of Part F of the EGRs
USI	Upper South Island, being the region covered by Transpower's DSP Trial
VOLL	Value of lost load

Executive summary

Transpower has identified the need and opportunity to introduce grid support contracts (GSCs) that will – in certain specific circumstances – enable it to contract with non-transmission options to augment or substitute for grid capacity.

Transpower has developed a strawman design of how GSCs might be used for risk management or transmission deferral.

The overall parameters of Transpower's 2008 strawman GSC product would be:

- Specific to transmission capacity problems, and hence offered only for specific regions and periods when these are occurring, or are forecast to occur. GSCs will not be offered to address generation adequacy problems.
- Transpower would not pick winners or pick losers: Transpower would identify a need, a potential provider would propose a commercial solution to the need, and Transpower would decide whether or not to offer a GSC for that proposal.
- To encourage innovation in non-transmission solutions, GSCs will be open to all non-transmission options, but with clear qualification and evaluation criteria to ensure reliability.
- To encourage competition in procurement, GSCs will be offered to successful tenders through an RFI and RFP process: qualification and evaluation criteria would be applied.
- GSCs will be contract for services, not for Transpower ownership. Transpower would be offering them in its capacity as grid owner. For those GSCs that require to be called or dispatch, this will be done by the System Operator on behalf of the grid owner.
- Cost recovery will be through the transmission pricing methodology (TPM), for which approval will be required through Part F of the EGRs. GSCs would only be offered as part of a reliability investment proposal for assets on the interconnected grid: they wil not be offered for connection asset issues or for economic investments.

GSCs as a risk management tool

Transpower has significant concerns over the risk to reliability of supply that might arise in the foreseeable future from insufficient transmission capacity resulting from:

- Delayed build of new transmission assets - whether for reasons of regulatory approval, obtaining consents under the RMA, acquiring property, or due to competition in world markets for transmission assets and expertise;
- Higher demand growth than was forecast at the time of investment decision, which would bring forward the need date; or
- Major asset failure - which is a growing concern given the age of Transpower's asset base.

GSCs could provide a useful product as part of a toolbox of approaches to managing such these risks.

GSCs as a transmission deferral tool

Another purpose that has been mooted for GSCs is the deferral of transmission investments. Given the tightness of the system currently and the urgent need for increased transmission capacity, Transpower does not consider that, overall, deferring transmission investment would be a good outcome for New Zealand. However there may be cases where the there is genuine option value in deferring an investment decision, so it does need to be considered on a case-by-case basis.

Where such option values do not exist, Transpower would not propose to use GSCs to push investment to the very edge of modelled 'just in time' limits. There are huge asymmetries of risk, with transmission 'better a year early than a day late'. Critically, to

plan to use GSCs for deferring an investment in this way would remove its advantage as the insurance instrument against the risks outlined above. As any GSCs for transmission deferral would be used at the very end of the project, in the year or years immediately prior to commissioning, they would be better left as the Plan B.

Reliability

Historically, the transmission grid was developed to link previously unconnected regions to provide greater levels of reliability through access to more generation resources. While initially undertaken for energy transport reasons, more recently investment has been for market efficiency too.

Using GSCs to maintain reliability therefore requires the GSCs to be highly reliable.

It is unrealistic to expect local generation or demand-side response to be able to achieve transmission levels of reliability. Rather, a reliability level of around 99% to 99.9% may be achievable. Even using these options it must be appreciated that reliability will decline, but they could still add value as a risk management tool. Lower levels of reliability would in Transpower's view not be acceptable.

A key issue in GSC design and operation would therefore be in ensuring that appropriate reliability criteria are set for proponents wishing to enter into GSCs.

Market distortion

A significant issue for our GSC design process is to what extent the use of GSCs could distort existing markets, in particular the wholesale generation investment and operations market. The wholesale electricity market is a multi-billion dollar per annum market, whereas the GSC market is likely to be in the order of some tens of millions per annum. In Transpower's view the wholesale electricity market has performed admirably over its ten years of operation (noting the industry stakeholder concerns over generation capacity investment and inter-seasonal fuel management with regard to dry years), enabling significant productive, allocative and investment efficiencies. Designing and operating GSCs to minimise interference in the wholesale market is essential.

Forms of GSC

DSP including non-market generation. Transpower has trialled small aggregated DSP in its 2007 Pilot and 2008 Trial. These demonstrated that, under certain conditions, blocks of aggregated small DSP sources can be made reliable. Significant issues arose in forecasting the time and size of need accurately enough at the time of call: Transpower is investigating these. This form of GSC would include, in addition to aggregated blocks, blocks made up of single large load (or in principle, but unlikely in practice, large non-market generation sources). Blocks would be called individually by the System Operator in accordance with instructions from Transpower as grid owner reflecting the contract terms. Blocks would be expected to deliver the contracted capacity: their reliability would be a paramount consideration in the design, procurement and operation of this form of GSC. Blocks would either be called ahead of time using a GENCO terminal, or be operated automatically post-contingent.

Voltage support. Transpower would use GSCs for contracting for voltage support over medium to long term planning horizons. They would in effect replace the voltage support ancillary service contracts over these timeframes. This will provide improved integration in grid planning, as the grid planner can better 'co-optimise' real and reactive power issues, and transmission and non-transmission reactive support options, over planning horizons from a technical, good electricity industry practice, and economic perspectives. In particular, the grid planner can test and contract for the availability and cost of future voltage support, rather than simply assume that this will be the eventual outcome of ancillary service voltage support contracts. Cost allocation would change from zonal under Part C to national under Part F transmission pricing methodology, aligning cost allocation for transmission and non-transmission reactive support solutions. The System Operator would still procure contracts of a short-term nature to cover for unanticipated reactive power

Market generation For market generation, avoiding interference in the operational market is paramount. GSCs would not be offered to define how generators would offer real power into the market, whether in time, quantity or price. Rather, GSCs would be limited to contributions to capital or other fixed 'up front' costs. In effect, GSCs would be used to buy certainty over a particular generator's development path – be it for example in time, equipment or location – to allow transmission to be safely designed around it. Proponents would be required to demonstrate that they are sufficiently committed to be able to deliver, and that their contract price is a fair and reasonable reflection of actual cost.

GSC design proposal

Transpower in this consultation document discusses issues in GSC design and operation and presents for feedback key features of a strawman design.

The discussion document includes the key features of Transpower's 2008 strawman design, for feedback from the industry and other interested parties.

Consultation feedback

Transpower is the transmission owner and System Operator for New Zealand. In undertaking these roles, Transpower has gained extensive experience in maintaining and enhancing transmission system reliability, and in operating the grid and the system. Transpower is however not an expert in demand-side participation, nor in the full range of commercial issues and incentives around generation investment and operation.

Transpower has concerns about some specific issues around GSC design and operation, and intends to offer a GSC product that minimises these risks. Transpower's main concern is how to obtain the benefits possible from GSCs without:

- compromising reliability;
- significant interference in the wholesale electricity market;
- significant distortions in electricity generation investment; or
- Transpower becoming relied on for energy as well as transmission capacity provision.

Transpower is considering the use of GSCs over the long term, recognising that they can introduce significant risk if not managed carefully. Transpower's preferred approach to introducing GSC is to start with tried and tested sources and gradually increase the number of sources in contracts over time. Transpower believes that taking a cautious approach initially rather than casting the net too wide and contracting with untried and untested sources is the prudent path at this time. This would avoid a situation developing where GSC performance requires Transpower to decrease the range of situations where GSCs would be considered, thereby limiting, due to initial unsuccessful security products, the potential benefits to the electricity market of GSCs.

Transpower is considering the use of GSCs over the long term, recognising that they can introduce significant risk if not managed carefully. Transpower's preferred approach to introducing GSC would be to start with tried and tested sources and gradually increase the number of sources in contracts over time. Transpower believes that taking a cautious approach initially rather than casting the net too wide and contracting with untried and untested sources is the prudent path forward at this time.

Transpower has, following a two year demand-side participation trial and consideration of the many complex issues and trade-offs involved, developed a 'strawman' GSC product design. This '2008 strawman' is explained and described in this paper to provide a starting point for your feedback. Specifically, Transpower requests that you consider the issues raised, and the extensive and complex interdependencies between them, and comment on the 2008 strawman GSC design features that are described throughout this document in blue boxes.

Transpower welcomes your feedback to assist us to offer a GSC product that provides an appropriate balance between capturing the possible benefits while minimising the potential downsides.

Submissions are sought by the end of January 2009: the process is explained in section 12.

Appendix D

3 GSC experience in New Zealand and overseas

3.1 International practice

Transpower engaged SAHA International an update and analysis of the use of grid support contracts internationally. In a previous report prepared for Transpower by PWC in 2006, it was concluded that:

> *"Of the jurisdictions reviewed, Australia appears to be the most progressive jurisdiction in deferring investment using generation contracts, with examples of such contracts being used in practice for some years. As such, the Australian experience may offer reasonable guidance on possible approaches and regimes for the use of network generation contracts in New Zealand, notwithstanding the regulatory differences between the jurisdictions."*

The process described above has been developed with regard to the regulatory and governance regimes in New Zealand, incorporating learnings from the Australian experience.

Since the PWC report was completed, the key international developments have included a growing recognition that:

- GSCs may be used to manage delays in transmission augmentation.
- Impacts on the wholesale market need to be minimised (unless they are mitigating existing anomalies in the market).

In broad terms, a GSC is a contractual arrangement facilitating a non-network alternative to a network augmentation required to meet mandated reliability obligations. A GSC may be entered into with any party who is capable, and prepared, to provide network support in lieu of a physical augmentation to the network. For example, this may be in the form of additional generation, a change in the pattern of operation of existing generation, or demand side management.[4]

Internationally, it would appear that reducing the locational market power of generators (to maintain the integrity of competitive wholesale markets) is the predominant reason for GSCs to be used. Under this paradigm, transmission constraints are seen as barriers to competition, and GSCs are used to avoid inefficient market outcomes. Avoiding transmission investment would appear to be a secondary – but perhaps an increasingly important – purpose. For instance:

- in California, reliability-must-run contracts (RMR) were developed to mitigate the special form of local market power that must-run generation could dictate. In particular, where the market price was insufficient to compensate the 'downstream[5]' generator for its operating costs, the RMR provided additional compensation in a way that did not affect market clearing prices.
- in Alberta, the long standing policy position was that transmission-must-run contracts (TMR) must not be used as a long-term substitute for transmission investment as transmission is *the agent of reliability and the facilitator of the competitive market*[6], and TMR can distort market outcomes. However, more recently (2005) this policy position has been moderated to allow TMR as a longer term solution if it is a cost effective alternative to transmission investment.

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[4] *Adapted from the definition of a Network Support Agreement (NSA) in Australia – see* Powerlink; "Response to AEMC Issues Paper – Congestion Management Review"; 13 April 2006; p2

[5] *i.e.* downstream *of the constraint. Similarly an 'upstream' generator is* upstream *of the constraint.*

[6] *see Alberta Department of Energy; "Alberta's Electricity Policy Framework"; 6 June 2005*

- in British Columbia (Canada), BCTC has recently (2006) undertaken to evaluate *non-wires* transmission alternatives where such alternatives have the potential to avoid or delay wires solutions. This stance was supported by the British Columbia Utilities Commission (BCUC) which directed BCTC to, *inter alia*, examine options for customer supplied transmission services, such as reactive power or RMR generation.[7]
- in Australia, the current definition of NSCSs[8] is that they are transmission network services that are critical to the maintenance of secure and reliable operation of the power system, by providing the capability to control the real or reactive power flow into or out of a transmission network in order to: (a) maintain the transmission network within its current, voltage or stability limits following a credible contingency event; or (b) enhance the value of spot market trading in conjunction with the central dispatch process. The value of spot market trading may be enhanced by increasing the *transfer capability* of the transmission network (within its secure operating limits).

Summarised by types of use of GSCs overseas:

Risk management

In the USA, GSCs have been relied on to provide capacity during contingencies, and have complemented transmission construction. However, more recently FERC has expressed frustration with such contracts and has called for them to be replaced by "market-based" solutions to the problem of compensating locally constrained units.

In Alberta, GSCs are seen as a stop-gap measure (e.g. to manage delays in transmission augmentation).

Transmission deferral

In Queensland, Powerlink have relied on GSCs to avoid 'more costly' transmission augmentations (per Regulatory Test). However, having avoided augmentation for several years, Powerlink are now building transmission to remove constraints.

In Alberta, GSCs are not allowed as a (long-term) substitute for transmission.

In British Columbia, BCTC recently assessed opportunities for non-wire transmission alternatives – but failed to identify any.

Reliability

In most jurisdictions examined (particularly the USA and Queensland), GSCs have been used to improve the reliability of the system.

Wholesale market impacts

In Australia, NSA is cited as helping to mitigate potential 'mispricing' problems in the NEM.

In Alberta, by way of contrast, the use of GSCs was seen to depress the wholesale market price, and a solution to this has not yet been identified.

A more detailed review of GSCs in other jurisdictions is set out in Appendix B.

3.2 Transpower's demand-side participation (DSP) Trial

As Transpower began to investigate the development of a GSC product, it became apparent that:

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[7] *British Columbia Utilities Commission in the Matter of British Columbia Transmission Corporation Transmission System Capital Plan 2006 to 2015 Application Decision; September 23, 2005*

[8] *GSCs are commonly referred to as Network Support Agreements (NSA) in the NEM. NSAs are a category of contract that NEMMCO (and others) more broadly refer to as Network Support and Control Services (NSCS).*

Appendix E

IEA DSM Programme
Task XV: Network Driven DSM

Dr David Crossley
Managing Director
Energy Futures Australia Pty Ltd

Workshop on Network Driven DSM
Auckland, 23 November 2007

Presentation Topics

Using DSM to support electricity networks

Motivation, objectives and work plan for Task XV

Task XV results so far

Selected case studies

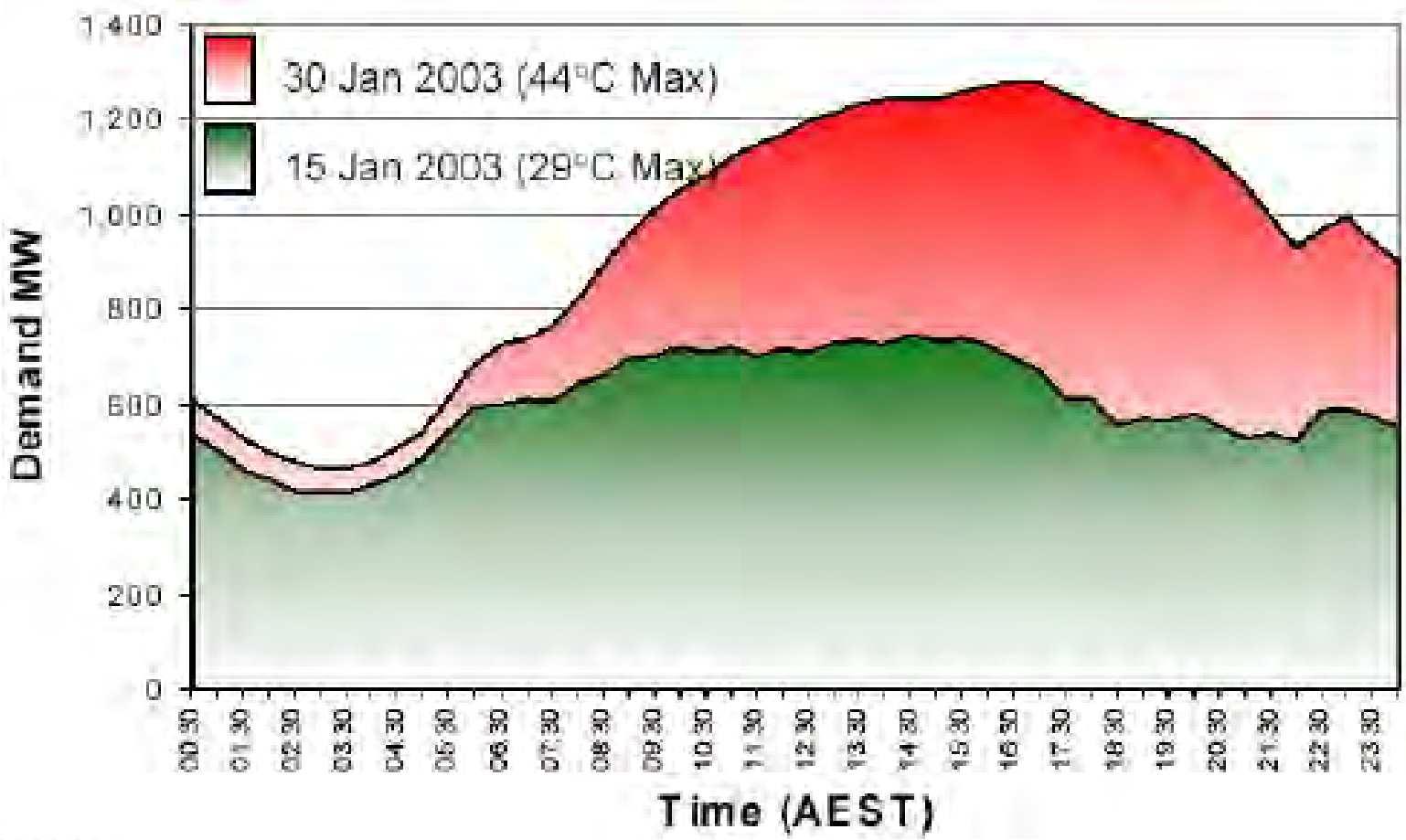
Conclusions

Information resources

Using DSM to Support Electricity Networks

Why Use DSM? (1)

Sydney West Bulk Supply Point Load Profile

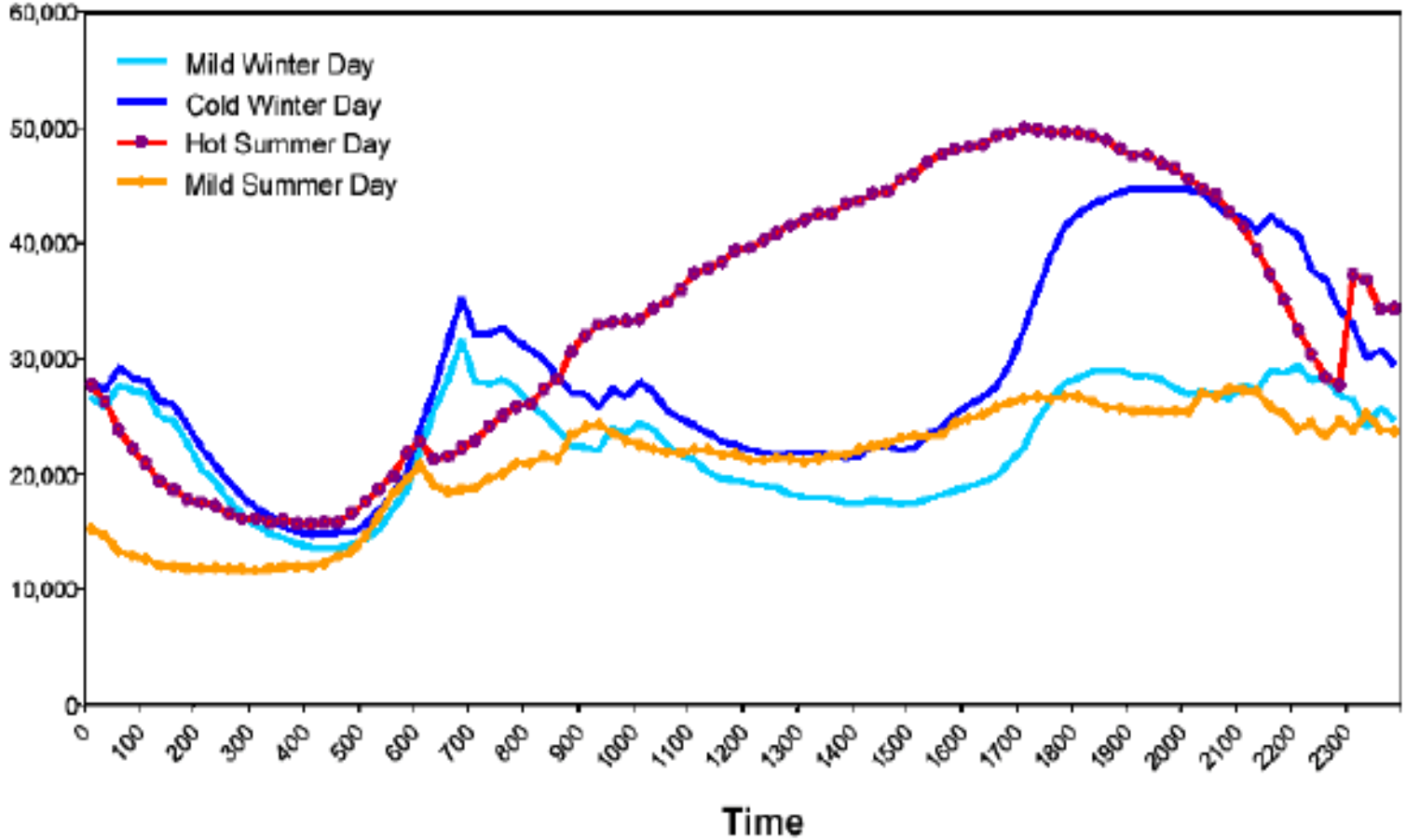


INTEGRAL energy
The power is in your hands

ENERGY FUTURES AUSTRALIA

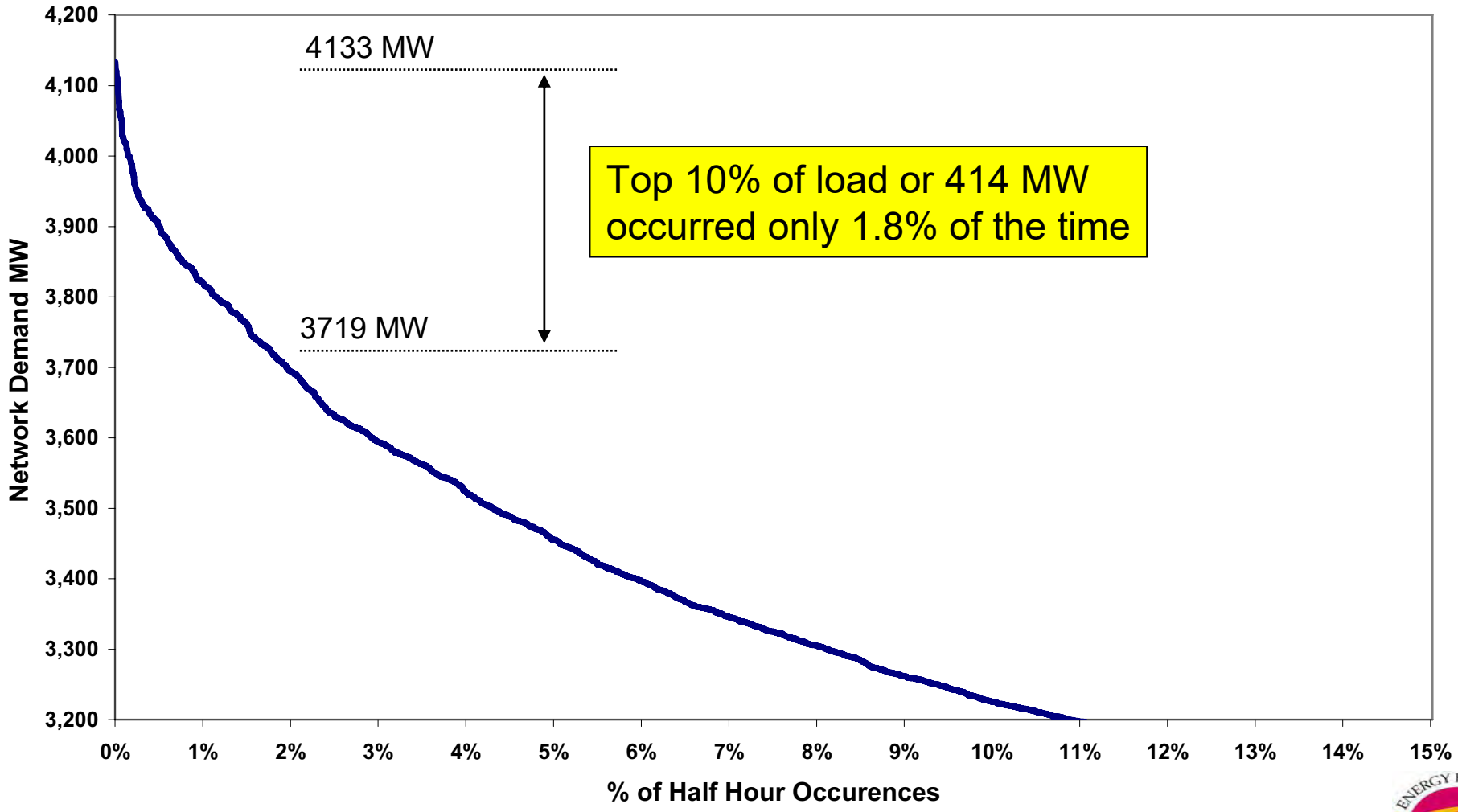
Why Use DSM? (2)

Predominantly Residential Load Profile



INTEGRAL energy
The power is in your hands

Why Use DSM? (3)


4133 MW
3719 MW
Top 10% of load or 414 MW occurred only 1.8% of the time
Network Demand MW
4,200
4,100
4,000
3,900
3,800
3,700
3,600
3,500
3,400
3,300
3,200
0%
1%
2%
3%
4%
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
% of Half Hour Occurences

What is Network-driven DSM (1)?

Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators

In Task XV, network-driven DSM is defined as follows:

Network-driven demand-side management is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation

What is Network-driven DSM (2)?

Task XV identifies the following two prime objectives for network-driven DSM:

- to relieve constraints on distribution and/or transmission networks at lower costs than building ‘poles and wires’ solutions; and/or
- to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support

Characteristics of Network Constraints

Network-driven DSM measures must address the particular characteristics of network constraints

In relation to timing, network constraints may be:

- narrow peak related – occurring strongly at the time of the system peak and lasting seconds, minutes or a couple of hours; or
- broad peak related – less strongly related to the absolute system peak, occurring generally across the electrical load curve and lasting several hours, days, months, years or indefinitely

In relation to the spatial dimension, network constraints can:

- occur generally across the network; or
- be associated with one or more specific network elements such as certain lines or substations

Motivation, Objectives and Work Plan for Task XV

Motivation for Task XV (1)

Prior to initiating Task XV, the IEA DSM Programme had not undertaken any work on the potential for DSM to cost-effectively relieve electricity network constraints

However, such constraints are becoming a significant problem in countries where electricity demand is increasing and network infrastructure ('poles and wires') is ageing

As loads grow and infrastructure reaches the end of its economic life, the potential cost of augmenting networks is increasing exponentially

In certain limited situations, network-driven DSM may be able to cost-effectively defer or even eliminate the requirement to build a 'poles and wires' solution

Motivation for Task XV (2)

In addition to relieving network constraints, DSM measures can also provide operational support services for electricity networks

Such network support services include: reactive supply and voltage control, regulation and frequency response, energy imbalances, spinning reserves, supplemental reserves, and generator imbalances

Task XV also covers the use of DSM measures to provide network support services.

Task XV Objectives (1)

To identify a wide range of DSM measures which can be used to:

- relieve electricity network constraints and/or
- provide network operational services

To further develop the identified network-driven DSM measures so that they will be successful in cost-effectively achieving network-related objectives

To investigate how existing network planning processes can be modified to incorporate the development and operation of DSM measures over the medium and long term

Task XV Objectives (2)

To develop ‘best practice’ principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources

To communicate and disseminate information about network-driven DSM to relevant audiences

To investigate in detail the role of load control and smart metering in achieving network-related objectives

Task XV Work Plan

Subtask 1: Worldwide Survey of Network-Driven DSM Activities

Subtask 2: Assessment and Development of Network-Driven DSM Measures

Subtask 3: Incorporation of DSM Measures into Network Planning

Subtask 4: Evaluation and Acquisition of Network-Driven DSM Resources

Subtask 5: Communication of Information About Network-Driven DSM

Subtask 6: Role of Load Control and Smart Metering in Achieving Network-related Objectives

Task XV Results So Far

Survey of Network-driven DSM Projects (1)

The survey identified 45 network-driven DSM projects undertaken over about the last 10 years

The survey focused on projects carried out in the original four countries participating in Task XV, Australia, France, Spain and the United States, but it also includes some projects from other countries

Detailed case studies of the projects were prepared and included in an on-line case study database

Survey of Network-driven DSM Projects (2)

The network-driven DSM projects included in the survey were classified by the major DSM measure implemented, as follows:

- distributed generation, including standby generation and cogeneration
- energy efficiency
- fuel substitution
- integrated DSM projects
- load management, including interruptible loads, direct load control and demand response
- power factor correction
- pricing initiatives, including time of use and demand-based tariffs

Survey of Network-driven DSM Projects (3)

The survey showed that network-driven DSM options can effectively:

- achieve load reductions on electricity networks that can be targeted to relieve specific network constraints; and
- provide a range of network operational services

Survey of Network-driven DSM Projects (4)

The survey also showed that all types of DSM measures can be used to relieve network constraints and/or provide network operational services

However, whether a particular DSM measures is appropriate and/or cost effective in a particular situation will depend on:

- the specific nature of the network problem being addressed; and
- the availability and relative costs of demand-side resources in that situation

Assessment & Development of DSM Measures (1)

Task XV concluded that the value of a network-driven DSM project varies among categories of stakeholders

The value may even vary among individual stakeholders (eg customers located in network-constrained areas vs customers located outside these areas)

Because the benefits are distributed among many different stakeholders, the project proponent is unlikely to capture all the benefits from such a project

Other parties who have not contributed to the cost of implementing the project may well receive some of the benefits

Assessment & Development of DSM Measures (2)

- To provide significant value to the proponent of a network-driven DSM project, the total benefits must be quite large and the proponent must be able capture a significant proportion of these benefits
- Task XV also identified a number of external and internal factors that may contribute to the success of network-driven DSM projects
- Network-driven DSM projects containing the same DSM measures tend to have a common set of factors which contribute to their success
- To this extent it is possible to identify sets of success factors that apply to each category of DSM measure

Assessment & Development of DSM Measures (3)

The challenge in designing a network-driven DSM project that will ultimately be successful in achieving its objectives is to:

- clearly identify the success factors for each of the DSM measures included in the project
- and then concentrate on optimising each of these factors

Assessment & Development of DSM Measures (4)

Task XV also:

- identified the network problems that each category of network DSM measures can address
- characterised the success factors which apply to each category; and
- examined how the DSM measures in each category should be implemented for them to be most effective in achieving network-related objectives

Incorporation of DSM into Network Planning (1)

Among the four countries so far studied in Task XV, planning processes for electricity transmission and distribution systems vary significantly

Variation occurs particularly in relation to:

- the types and functions of the various organisations involved
- the detailed planning processes and methodologies used
- the policy and regulatory regimes within which electricity network businesses operate

However, there is sufficient commonality to identify a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks

Incorporation of DSM into Network Planning (2)

There are four key areas in which such changes can and should be made:

1. Forecasting future electricity demand
2. Communicating information about network constraints
3. Developing options for relieving network constraints
4. Establishing policy and regulatory regimes for network planning

Incorporation of DSM into Network Planning (3)

1. Forecasting future electricity demand

Forecasting methodologies frequently reduce global load forecasts by an assumed (usually small) amount to take account of DSM activity

Such methodologies discount the potential contribution by DSM towards supporting electricity networks

Forecasting methodologies for network planning should be modified to recognise more accurately the potential contribution of DSM

Incorporation of DSM into Network Planning (4)

2. Communicating information about network constraints

Information about future network constraints is often retained inside electricity network businesses

It is then very difficult for anyone else to propose options for relieving network constraints

Network businesses should make this information publicly available so that other organisations with the required expertise can develop DSM options to relieve the constraints

Incorporation of DSM into Network Planning (5)

3. Developing options for relieving network constraints

Network businesses should provide formal opportunities for third parties with expertise in DSM to participate in the development of options that use demand-side resources to relieve network constraints

Incorporation of DSM into Network Planning (6)

4. Establishing policy and regulatory regimes for network planning

Governments and regulators should change policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks

There are two ways in which this can be achieved:

- by providing policy and regulatory incentives to network businesses; and/or
- by imposing policy and regulatory obligations on network businesses

Evaluation and Acquisition of DSM Resources (1)

A survey of electricity network business practices in Australia, France, Spain and the United States identified a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks

The details of these processes varied substantially, particularly depending on the regulatory regime applied to the network businesses

Evaluation and Acquisition of DSM Resources (2)

Good DSM resource acquisition processes include the following stages:

- assessing the need for DSM resources
- identifying and evaluating available DSM resources
- contacting potential providers of DSM resources
- negotiating the provision of DSM resources; and
- acquiring and implementing the DSM resources

Best practices within each of these stages are tailored to the nature of each DSM resource and to the specific purpose for which the resource is required

Role of Load Control and Smart Metering

An on-line database of load control and smart metering technologies has been established

The database currently contains details of 11 technology products

This number will be increased as participating countries send information about products

Further Work in Task XV

Further work to be carried out includes:

Subtask 1: Development of not less than five new case studies of load control and smart metering projects

Subtasks 2, 3 and 4: Addition of material from the new participating countries: India, New Zealand and South Africa

Subtask 5: Production of two editions of the Task XV Newsletter

Subtask 6: Identification of best practice in the use of load control and smart metering to achieve network-related objectives

Selected Case Studies

Classification of DSM Activities in the Survey

DG - distributed generation, including standby generation and cogeneration

EE - energy efficiency

FS - fuel substitution

IP - integrated demand management projects

LM - load management, including load shifting, direct load control, interruptibility and market-driven demand response

PC - power factor correction

PI - pricing initiatives, including time of use and demand-based tariffs

Network DSM Case Study 1

DG04 Chicago Energy Reliability and Capacity Account - USA

- This project makes extensive use of distributed generation, including standby generators and photovoltaics
- Chicago City developed a SCADA system to link natural-gas fired standby generators located in public buildings to a central operating facility; this makes them available as a network of distributed generators for use in system emergencies
- The City also expects to dispatch the standby generators at periods of high system prices; income from power generation at peak periods will help to pay for the costs of the program
- The City has also negotiated an arrangement with a photovoltaics manufacturer to locate a manufacturing plant in Chicago and has installed photovoltaic arrays at schools and museums throughout the City

Network DSM Case Study 2

EE01 Efficient Lighting Project DSM Pilot - Poland

- This pilot project was designed to use compact fluorescent lamps (CFLs) to demonstrate to Polish electric utilities the use of DSM to defer distribution and transmission investments
- The pilot aimed to reduce peak power loads in geographic areas where the existing electricity network capacity was inadequate
- Three cities and their regional electricity utilities were selected to participate in the DSM pilot; the cities had areas with electricity network capacity problems
- Subsidised CFLs were made available to city residents using discount coupons; the largest discounts were available to residents of network constrained areas
- Modelling results showed that during the local peak hour on the peak day of the year, load reductions of about 15% were achieved in the target network constrained areas

Network DSM Case Study 3

FS02 Binda Bigga Demand Management Project - Australia

The aim of this project was to defer the need for the upgrade of a rural feeder line by reducing the demand for energy during the winter evening peak periods

Country Energy developed a package that enabled local residents to affordably switch from electric to gas appliances; the package offered residents:

- discounted gas room heaters and cooking stoves
- free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling
- gas credits of AUD 170 per appliance

Overall 70 customers purchased an Energy Saver Package, installing 106 appliances in total; this exceeded the target load reduction of 200kVA

Network DSM Case Study 4

IP04 Olympic Peninsula Non-wires Solutions Pilot - USA

Bonneville Power Authority is carrying out several pilot projects to determine whether it is possible to use “non-wire solutions” to defer a transmission line construction project

DSM measures being employed in pilot projects on the Olympic Peninsula include: direct load control, demand response, voluntary load curtailments, networked distributed generation and energy efficiency

One particularly interesting DSM measure is the use of Grid-Friendly™ appliances which sense frequency disturbances in the electricity network and reduce load to act as spinning reserve - no communications technology is required beyond the network itself

Some DSM measures will be aggregated into a demonstration of how a future electricity network might function

Network DSM Case Study 5

LM06 LIPAedge Direct Load Control Program - USA

Long Island Power Authority uses central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction

The system operator interfaces with the resource through a web-based system; two-way pagers are used to transmit a curtailment order to 20,000 thermostats and to receive acknowledgment and monitoring information

The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered

The command is received and acted upon by all loads, providing full response within about 90 seconds; this is far faster than generator response, which requires a 10-minute ramp time

Network DSM Case Study 6

PC01 Marayong Power Factor Correction Program - Australia

This project aimed to reduce the load on particular zone substation and thereby defer the capital expenditure required to strengthen a specific feeder

The local electricity distributor, Integral Energy, installed power factor correction equipment in the low voltage network outside customers' premises (not on the customer side of the meter)

Integral paid for the equipment and the installation

This program was implemented without the involvement of customers

Network DSM Case Study 7

PI05 End User Flexibility by Efficient Use of ICT - Norway

This was a large scale pilot project involving two network operators and six technology vendors

The project included: two way communication to 10,984 mainly residential customers; automated meter reading; and direct load control of water heaters

Customers were offered a choice of a standard or TOU network tariff and/or a standard or hourly spot price retail tariff

Average load reductions per household:

- ToU network tariff – 0.18 kWh/h
- Hourly spot price for energy – 0.4 - 0.6 kWh/h
- Direct load control of water heaters – 0.5 kWh/h
- ToU network tariff plus hourly spot price – 0.3 - 1.0 kWh/h

Conclusion

Conclusion (1)

While there is increasing use of DSM measures to support electricity networks, Task XV is the first broad and systematic investigation of this particular application of DSM

So far, Task XV has concluded that DSM can be successfully used to support electricity networks in two main ways:

- by relieving constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions; and/or
- by providing services for electricity network system operators, achieving peak load reductions with various response times for network operational support

Conclusion (2)

Through participating in Task XV to date, country Experts and representatives have been able to:

- understand the advantages and disadvantages of network-driven DSM measures as alternatives to network augmentation
- gain information about network-driven DSM measures currently in use in other countries and about the relative effectiveness of these measures
- understand the factors which lead to a network-driven DSM measure being effective

Conclusion (3)

Participating in the Task XV extension will enable countries to:

- understand how load control and smart metering can be used to defer network augmentation and to provide network operational services
- gain information about the functionalities and capabilities of load control and smart metering devices
- gain information about load control and smart metering projects currently being implemented in other countries and about the relative effectiveness of these projects
- identify best practice in the use of load control and smart metering to achieve network-related objectives

Information Sources

David Crossley: crossley@efa.com.au

Reviews of documents on DSM and energy efficiency in Australia are available at my company's website: www.efa.com.au/dsmdocs.html

The International Energy Agency DSM Programme website is at: www.ieadsm.org

The IEADSM Task XV website is at: www.ieadsm.org/ViewTask.aspx?ID=16&Task=15&Sort=0

IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

CENTRAL VANCOUVER ISLAND TRANSMISSION PROJECT

DECISION

December 10, 2008

Before:

A.W. Keith Anderson, Panel Chair & Commissioner
Anthony J. Pullman, Commissioner
Michael R. Harle, Commissioner

receive service from the public utility", as well as Sections 64.01 and 64.02 for the achievement of electricity self!sufficiency.

The Commission Panel agrees with BCTC that the sole Intervenor who questioned the need for the Project may have misinterpreted BCTC's response to BCUC 1.16.2, and notes that the Project received support from several Intervenors.

In the situation at hand the Commission Panel finds that BCTC's use of the N!1 standard is an acceptable planning standard for system reliability. The Commission Panel determines that BCTC has established the need to reinforce the CVI transmission system by an ISD of October 2010 to provide adequate transmission infrastructure in order to reliably serve BC Hydro's load in the region.

2.3 Potential "Non-wires" and Other Solutions

BCTC states that as well as the alternatives discussed in Section 2.4 below it examined the following "non!wires" and other solutions:

- Demand Side Management ("DSM");
- Local Generation;
- Remedial Action Schemes;
- Curtailment; and
- Juan de Fuca Cable Project ("JdF").

<u>Demand Side Management</u>

BCTC states that one of the purposes of DSM initiatives is to defer the need to add infrastructure to meet growing demand, but, in the case of the CVI Project, existing customer demand already exceeds the firm capacity of the 138 kV transmission system with the result that DSM programs

have very little effect in managing the existing customer demand relative to the shortfall in capacity. BCTC also points out that the existing forecast of demand growth from the BC Hydro 2006 Substation Load Forecast includes the impacts of existing and planned DSM programs, so the forecast load growth in the CVI Area Study is the residual load growth after the effects of demand side programs have been taken into account (Exhibit B!1, p. 43).

Local Generation

BCTC states that a new generation supply source in the Nanaimo area at Duke Point would have resolved the capacity constraints on the 138 kV transmission system in CVI by alleviating the overloading on both circuits 1L115/116 and the transformers at VIT, by injecting a new supply source directly into the 138 kV transmission system near Nanaimo, the major load centre in CVI. However, since that project was cancelled, no other generation projects in the region have been proposed that would alleviate the need to upgrade the transmission system. In addition, any new generation project that may be announced would not likely be in service by October 2010, to meet the required ISD for the proposed solution to the capacity constraints in CVI (Exhibit B!1, p. 43).

Remedial Action Schemes

BCTC states that it will continue to employ RAS on its transmission systems, because they are an effective means of deferring the additions of infrastructure. In the case of the CVI transmission system, it notes that customer demand has exceeded the ability of the existing RAS to maintain the 138 kV transmission system during times of heavy usage, and is no longer effective. BCTC notes that redeploying the RAS to LTZ or PVL from JPT would not be an option, because it would increase the loading on the VIT transformers, and would not mitigate the need for additional firm transmission capacity in the CVI area to prevent load shedding during peak usage and a single contingency outage (Exhibit B!1, p. 44).

Curtailment

BCTC does not address curtailment in its Application. However, BCTC addressed the Customer Capacity Curtailment Contracts entered into by BC Hydro and certain of its customers, and stated that two such curtailment contracts could result in load curtailment in the CVI area, and that the maximum load curtailment that might be available was 150 MW in the vicinity of VIT and 6 MW in the vicinity of JPT (Exhibit B!8, BCUC 3.117.4). BCTC stated that while these contracts can result in load curtailment, the nature of the contracts is such that they cannot be used to avoid or defer construction of the CVI Project, and that they were intended to serve as a resource option for supply to the BC Hydro system during periods of constraint in generating capacity. In particular, the Customer Capacity Curtailment Contracts were to serve as an alternative to the import of energy or the use of Burrard Thermal Generating Station for generation purposes when the cost of energy is high. Consequently, these contracts were designed to meet system generation deficiencies when other alternatives would likely still be available for system supply purposes, not constraints within the CVI regional transmission system.

BCTC stated that the Customer Capacity Curtailment Contracts were based on voluntary load curtailment of large customers that could facilitate an orderly shut down of their plant processes in a way that incurred minimal cost to them, including any disruption to their production process, with four hours notice, but that load curtailment in this manner was not sufficient to meet transmission system constraints since, in order to avoid system voltage collapses and excessive thermal overloads, a fast means of load shedding was required, rather than the planned and orderly curtailment of load over a period of four hours. BCTC concluded that the existing load curtailment contracts located in the CVI area were not practical options to resolve transmission system constraints (Exhibit B!9, BCUC 3.117.4.1).

In addition, BCTC stated that there was no guarantee that the customer would curtail the required load in the CVI area when load curtailment was requested, because the contract for 150 MW of curtailment covered more than one plant, and provided the customer with the latitude to determine which of its plant(s) would provide the requested load curtailment, and to what extent.

The extent of load curtailment at any one plant was at the sole discretion of the customer and could depend on the status of the plant itself or market conditions for the products produced by any specific plant, and that there was no requirement, and no certainty, that customers would curtail load in the CVI region.

BCTC stated that the Customer Capacity Curtailment Contracts do not avoid load shedding under N!1 conditions, and that they are not sufficient to ensure adequate capacity under an N!1 contingency condition for the remaining unshed load. In other words, load shedding at distribution substations will be required after customers with curtailment contracts have been curtailed (Exhibit B!9, IR 3.117.4.2).

Juan de Fuca Cable Project

In addition to potential "non!wires" solutions BCTC stated that it considered JdF, a proposed international transmission interconnection between Pike Lake Substation in the Victoria area, and Port Angeles, WA. JdF has reported that the first phase of this cable project using HVDC Light technology could be in!service in 2009 to provide up to 550 MW of capacity. BCTC states that neither JdF, nor any other bulk transmission supply source such as the Vancouver Island Transmission Reinforcement Project ("VITR"), will provide relief to the capacity constraints that exist on the CVI system, since the capacity constraints are the result of customer demand exceeding the capacity of the existing 138 kV transmission system in the CVI area, and that adding a new source of supply to the 230 kV transmission system up stream of VIT and DMR supply points does not help alleviate the constraints that result in overloading on the 138 kV transmission system (Exhibit B!1, pp. 42!43).

CALIFORNIA natural resources AGENCY

ARNOLD SCHWARZENEGGER, Governor
MIKE CHRISMAN, Secretary for Natural Resources

For Immediate Release: Aug. 3, 2009

Contact: Sandy Cooney
(916) 653-9402

California Climate Adaptation Strategy Released

Discussion Draft Announcement Triggers 45-Day Public Comment Period

Sacramento, Calif. — California's Natural Resources Agency today released a comprehensive plan to guide adaptation to climate change, becoming the first state to develop such a strategy. The 2009 California Climate Adaptation Strategy Discussion Draft summarizes the latest science on how climate change could impact the state, and provides recommendations on how to manage against those threats in seven sector areas. Today's release sets in motion a 45-day public comment period.

"In keeping with the Governor's effort to fight climate change head on, re-examining the way we work and making adjustments accordingly is in many ways the most important thing we can do," said Secretary for Natural Resources Mike Chrisman. "Of all the difficult challenges that we've faced on this planet, environmental or otherwise, the greatest positive influence has happened when people acknowledge the problem, recognize their role in solving that problem and alter their behavior so that the change lasts. Adapting to climate change is a fundamental example of this principle"

Adaptation is a relatively new concept in California climate policy. The term generally refers to response efforts that combat the impacts of climate change – adjustments in natural or human systems to actual or expected climate changes in order to minimize harm or take advantage of opportunities.

In addition to Natural Resources, the state agencies involved in developing the draft strategy include Environmental Protection, Business, Transportation and Housing, Health and Human Services and the Department of Agriculture. The discussion draft focuses on seven different sectors that include: Public Health; Biodiversity and Habitat; Ocean and Coastal Resources; Water Management; Agriculture; Forestry; and Transportation and Energy Infrastructure. The strategy is a direct response to Gov. Schwarzenegger's November 2008 Executive Order S-13-08 that specifically asks to the Natural Resources Agency to identify how state agencies can respond to rising temperatures, changing precipitation patterns, sea level rise, and extreme natural events. As data continues to be developed and collected, the state's adaptation strategy will be updated to reflect current findings.

Rather than address the detailed impacts, vulnerabilities, and adaptation needs of every sector, those determined to be at greatest risk are prioritized.

-more-

Preliminary recommendations include:

• Establish a Climate Adaptation Advisory Panel to further assess California's climate change risks.
• Consider project alternatives that avoid significant new development in areas prone to flooding, sea-level rise, temperature changes, and precipitation changes.

• To the extent possible, communities should amend general plans and local coastal plans to avoid potential climate impacts.

• Fire fighting agencies should begin immediately to include climate change impact information into fire program planning.

• Major development and infrastructure projects should consider climate change impacts in order to comply with California Environmental Quality Act guidelines.

• Alter water use patterns as climate change will likely shift existing supplies and flows including Delta water supply and water quality. Improve Delta ecosystem and stabilize water supplies as developed in the Bay Delta Conservation Plan.

• Implement strategies to achieve a statewide 20 percent reduction in per capita water use by 2020, expand available state water storage, and implement the Delta Vision Cabinet Group recommendations to improve Delta water supply, water quality, and ecosystem conditions. Support agricultural water use efficiency.

• Coordinate hazard mitigation plans and assessments for managing increasing fire risk, flood, heat induced mortalities, and other hazards due to climate change.

• The California Department of Public Health will develop guidance for use by local health departments and other agencies to assess mitigation and adaptation strategies, which include impacts on vulnerable populations and communities and assessment of cumulative health impacts.

• Manage public health, infrastructure or habitat, to the extent that these are subject to climate change impacts, from sea level rise, increased temperature, and changing precipitation. This includes assessments of land use, housing and transportation proposals that could impact health, greenhouse gas emissions, and community resilience for climate change in keeping with SB 375 that addresses creating sustainable communities.

• Identify key California land and aquatic habitats and species from existing research that could be extinct this century due to climate change and develop a plan for expanding existing protected areas or altering water management systems that allow for climate change impacts.

• Work to meet projected population growth and increased energy demand with greater energy conservation. Renewable energy supplies should be enhanced through the Desert Renewable Energy Conservation Plan to reach a goal of 33 percent of the state's energy supply from renewable sources by 2020 in ways that protect sensitive habitat.

-more-

• Climate change research can and should be used for state planning purposes, and new climate change impact research should be funded and expanded. By January 2010, a Web-based map and interactive Web site should be developed and regularly updated by the California Energy Commission so as to be useful for local decision-makers.

California's ability to manage its climate risks through adaptation is dependent upon a number of critical factors including; economic resources, technology, infrastructure, institutional support and effective governance, public awareness, access to the best available scientific information, sustainably-managed natural resources, and equity in access to these resources. As the 2009 California Climate Adaptation Strategy Discussion Draft illustrates, the state has the ability to strengthen its capacity in all of these areas.

Two public meetings will be held to discuss the 2009 California Climate Adaptation Strategy Discussion Draft.

Public Stakeholder Meeting Schedule:

Thursday, Aug. 13, 2009
California Department of Food and Agriculture Building
1220 N Street, Sacramento, CA 95814
9 a.m. to 1 p.m.

Call In Number: 1-877-536-5793
Participant Code: 344390

Second Meeting
Date and Time TBA
Los Angeles, CA

Comments may also be submitted in writing to:

Adaptation
Natural Resources Agency
1416 Ninth Street, Suite 1311
Sacramento, CA 95814

or by email adaptation@resources.ca.gov.

To view the 2009 California Climate Adaptation Strategy Discussion Draft in its entirety, visit http://www.climatechange.ca.gov/adaptation/.

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Executive Summary

2009 California Climate Adaptation Strategy

Discussion Draft

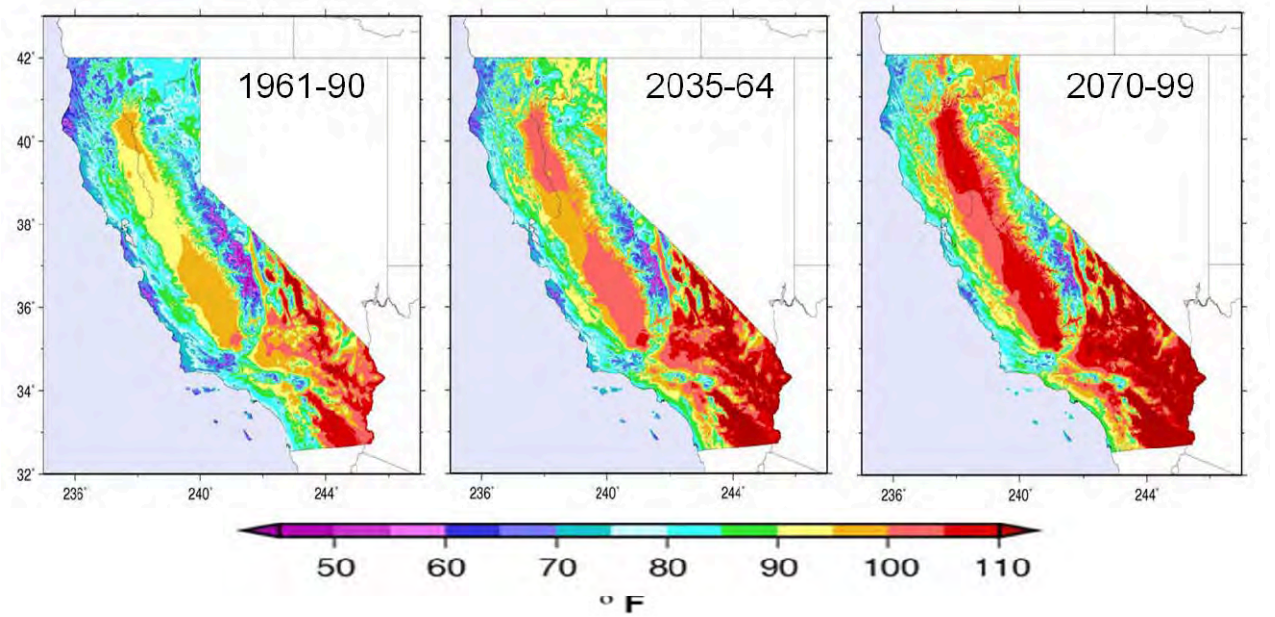
A Report to the Governor of the State of California in Response to Executive Order S-13-2008

Public Review Draft

California natural resources AGENCY

Appendix H

Figure 1. California Historical & Projected July Temperature Increase 1961-2099



Source: Dan Cayan et al. 2009.

Appendix H

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EXECUTIVE SUMMARY

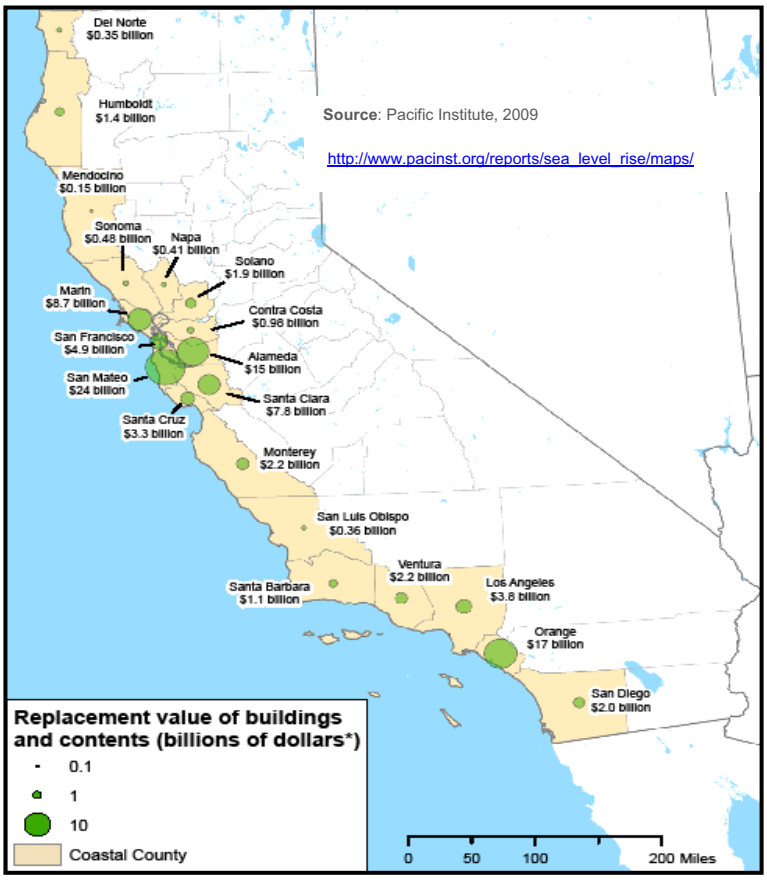
The Golden State at Risk

Climate change is already affecting California. Sea levels have risen by as much as seven inches along the California Coast over the last century, increasing erosion and pressure on the state's infrastructure, water supplies, and natural resources. The state has also seen increased average temperatures, more extreme hot days, fewer cold nights, a lengthening of the growing season, shifts in the water cycle with less winter precipitation falling as snow, and both snowmelt and rainwater running off sooner in the year.

These climate driven changes affect resources critical to the health and prosperity of California. For example, forest wildland fires are becoming more frequent and intense due to dry seasons that start earlier and end later. The state's water supply, already stressed under current demands and expected population growth, will shrink under even the most conservative climate change scenario. Almost half a million Californians, many without the means to adjust to expected impacts, will be at risk from sea level rise along bay and coastal areas. California's infrastructure is already stressed and will face additional burdens from climate risks. And as the Central Valley becomes more urbanized, more people will be at risk from intense heat waves.

If the state were to take no action to reduce or minimize expected impacts from future climate change, the costs could be severe. A 2008 report by the University of California, Berkeley and the non-profit organization Next 10 estimates that if no action is taken in California, damages across sectors would result in "tens of billions of dollars per year in direct costs" and "expose ***trillions*** of dollars of assets to collateral risk." More specifically, the report suggests that of the state's $4 trillion in real estate assets "$2.5 trillion is at risk from extreme weather events, sea level rise, and wildfires" with a projected annual price tag of up to $3.9 billion over this century depending on climate scenarios (www.next10.org/research/research_ccrr.html). The figure at right, from a study by the Pacific Institute, shows coastal property at risk from projected sea level rise by county with replacement values as high as $24 billion in San Mateo County.

Figure 2: *Replacement value of buildings and contents vulnerable to a 100 year coastal flood with 1.4 meters of sea level rise*



Source: Heberger et al. 2009.

California understands the importance of addressing climate impacts today. The state strengthened its commitment to managing the impacts from sea level rise, increased temperatures, shifting precipitation and extreme weather events when Governor Arnold Schwarzenegger signed Executive Order (EO) S-13-08 on November 14, 2008. The order called on state agencies to develop California's first strategy to identify and prepare for these expected climate impacts.

The *2009 California Climate Adaptation Strategy Discussion Draft* report summarizes the best known science on climate change impacts in the state to assess vulnerability and outline possible solutions that can be implemented within and across state agencies to promote resiliency. This is the first step in an ongoing, evolving process to reduce California's vulnerability to climate impacts.

The California Natural Resources Agency (CNRA) has taken the lead in developing this draft adaptation strategy, working through the Climate Action Team (CAT). Seven sector-specific working groups led by 12 state agencies, boards and commissions, and numerous stakeholders were convened for this effort. The strategy proposes a comprehensive set of recommendations designed to inform and guide California decision makers as they begin to develop policies that will protect the state, its residents and its resources from a range of climate change impacts. The CNRA will revise this draft adaptation strategy based on public input gathered over the next 45 days.

California's Climate Adaptation Strategy

As the climate changes, so must California. To effectively address the challenges that a changing climate will bring, climate adaptation and mitigation (i.e., reducing state greenhouse gas (GHG) emissions) policies must complement each other, and efforts within and across sectors must be coordinated. For years, the two approaches have been viewed as alternatives, rather than as complementary and equally necessary approaches.

Adaptation is a relatively new concept in California policy. The term generally refers to efforts to respond to the *impacts* of climate change – adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of beneficial opportunities.

California's ability to manage its climate risks through adaptation depends on a number of critical factors including its baseline and projected economic resources, technologies, infrastructure, institutional support and effective governance, public awareness, access to the best available scientific information, sustainably-managed natural resources, and equity in access to these resources.

As the *2009 California Climate Adaptation Strategy Discussion Draft* illustrates, the state has the ability to strengthen its capacity in all of these areas. In December 2008, the California Air Resources Board released the state's *Climate Change Scoping Plan*, which outlines a range of strategies necessary for the state to reduce its GHG emissions to 1990 levels by 2020. Many climate mitigation strategies, like promoting water and energy efficiency, are also climate adaptation strategies. By building an adaptation strategy on existing climate science and frameworks like the Scoping Plan, California has begun to effectively anticipate future challenges and change our actions that will ultimately reduce the vulnerability of residents, resources and industries to the consequences of a variable and changing climate.

To ensure a coordinated effort in adapting to the unavoidable impacts of climate change, the *2009 California Climate Adaptation Strategy Discussion Draft* was developed using a set of guiding principles:

- Use the best available science in identifying climate change risks and adaptation strategies.
- Understand that data continues to be collected and our knowledge about climate change is still evolving. As such, an effective adaptation strategy is "living" and will itself be adapted to account for new science.
- Involve all relevant stakeholders in identifying, reviewing, and refining the state's adaptation strategy.
- Establish and retain strong partnerships with federal, state, and local governments, tribes, private business and landowners, and non-governmental organizations to develop and implement adaptation strategy recommendations over time.
- Give priority to adaptation strategies that initiate, foster, and enhance existing efforts that improve economic and social well-being, public safety and security, public health, environmental justice, species and habitat protection, and ecological function.
- When possible, give priority to adaptation strategies that modify and enhance existing policies rather than solutions that require new funding and new staffing.
- Understand the need for adaptation policies that are effective and flexible enough for circumstances that may not yet be fully predictable.
- Ensure that climate change adaptation strategies are coordinated with the California Air Resources Board's AB 32 Scoping Plan process when appropriate, as well as with other local, state, national and international efforts to reduce GHG emissions.

The *2009 California Climate Adaptation Strategy Discussion Draft* takes into account the long-term, complex, and uncertain nature of climate change and establishes a proactive foundation for an ongoing adaptation process. Rather than address the detailed impacts, vulnerabilities, and adaptation needs of every sector, those determined to be at greatest risk are prioritized.

The development of the adaptation strategies presented within this report was spearheaded by the state's resource management agencies. CNRA staff worked with seven sector-based Climate Adaptation Working Groups (CAWGs) focused on the following areas: public health; ocean and coastal resources; water supply and flood protection; agriculture; forestry; biodiversity and habitat; and transportation and energy infrastructure.

Working group experts have an intimate knowledge of California's resources, environments, and communities, and also of the state's existing policy framework and management capabilities. This understanding informs the draft adaptation strategy and ensures a realistic assessment of adaptive capacities, current limitations, and future needs.

A Collaborative Approach

This draft adaptation strategy could not have been developed without the involvement of numerous stakeholders. Converging missions, common interests, inherent needs for cooperation, and the fact that climate change impacts cut across jurisdictional boundaries will require governments, businesses, non-governmental organizations, and individuals to minimize risks and take advantage of potential planning opportunities.

Throughout the development of this report, it became increasingly clear that overlapping missions and goals will require agencies and organizations at all levels to work together to develop close partnerships with regard to climate adaptation. This is the only means by which the far reaching effects of climate impacts can be addressed efficiently and effectively while avoiding potential conflicts. The Comprehensive State Adaptation Strategies chapter underscores the need for collaboration and identifies where cross-sector relationships are necessary.

To further enhance stakeholder participation, seven Climate Adaptation Working Groups (CAWGs) initiated a process that allowed for consultation with stakeholders through public workshops and review opportunities. This input has considerably shaped the content and refinement of this draft report. However, future updates of the draft adaptation strategy will require ongoing input through active stakeholder engagement and an even closer integration of state agency efforts. Public comment gathered during the next 45 days will be incorporated into recommendations and a final version of the report (see www.climatechange.ca.gov/adaptation).

In order to best analyze climate change risks, the *2009 California Climate Adaptation Strategy Discussion Draft* draws on years of state-specific science and impacts research, largely funded through the California Energy Commission's Public Interest Energy Research (PIER) Program and an engaged research community. The research provides for an understanding of the climate-related risks California will face and has significantly contributed to greater public awareness of climate change. As data continues to be developed and collected, the state's adaptation strategy will be updated to reflect current findings.

Preliminary Recommendations

The preliminary recommendations outlined in this draft adaptation strategy were developed by CNRA staff, CAWGs, the CAT, and from public comments. The public comment period will collect input from stakeholders about how these draft recommendations should be modified, if necessary. It is recognized the implementation of the following strategies will require significant collaboration among multiple stakeholders to ensure they are carried out in a rational, yet progressive manner over the long term. These strategies distinguish between near-term actions that will be completed by the end of 2010 and long-term actions to be developed over time, and are covered in more detail in the sector chapters in Part II of this report.[1]

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[1] Each of the twelve Executive Summary strategies is drawn from multiple strategies within the subsequent sector specific and cross-sector adaptation strategy chapters. The recommendations here may not reflect exact wording of individual sector recommendations but relate to their core message. Each Executive Summary recommendation here lists the sector and recommendation number using the following acronyms to identify the sector: Public Health (PH), Biodiversity

Key recommendations include:

1. A Climate Adaptation Advisory Panel (CAAP) will be appointed to assess the greatest risks to California from Climate Change and recommend strategies to reduce those risks building on California's Climate Adaptation Strategy. This Panel will be convened by the California Natural Resources Agency, in coordination with the Governor's Climate Action Team, to complete a report by December 2010. The CNRA will continue to act as the lead Climate Adaptation Office until subsequent guidance is provided by the CAAP.

2. California must change its water management and uses because climate change will likely create greater competition for limited water supplies needed by the environment, agriculture, and cities. As directed by the Governor, state agencies must implement strategies to achieve a statewide 20 percent reduction in per capita water use by 2020, expand surface and groundwater storage, implement the Delta Vision Cabinet Group recommendations to fix Delta water supply, quality, and ecosystem conditions, support agricultural water use efficiency, and improve state-wide water quality. Improve Delta ecosystem conditions and stabilize water supplies as developed in the Bay Delta Conservation Plan. (BH-2, W-3, 6, and 7; A-3; TEI-3).

3. Consider project alternatives that avoid significant new development in areas that cannot be adequately protected (planning, permitting, development, and building) from flooding due to climate change. The most risk-averse approach for minimizing the adverse effects of sea level rise and storm activities is to carefully consider new development within areas vulnerable to inundation. State agencies should generally not plan, develop, or build any new significant structure in a place where that structure will require significant protection from sea-level rise, storm surges, or coastal erosion during the expected life of the structure. However, vulnerable shoreline areas containing existing and proposed development that have regionally significant economic, cultural, or social value may have to be protected, and in-fill development in these areas should be accommodated. State agencies should incorporate this policy into their decisions, and other levels of government are also encouraged to do so. (CS-2; OCR-1 and 2; W-4; TEI -1).

4. All state agencies responsible for the management and regulation of public health, infrastructure or habitat subject to significant climate change should prepare as appropriate agency-specific adaptation plans, guidance, or criteria by September 2010. (PH-8; BH-1, 2, and 6; OCR-3; F-1 and 2; TEI-2 and 5).

5. All significant state projects, including infrastructure projects, must consider climate change impacts, as currently required under CEQA Guidelines Section 15126.2. (BH-2).

6. The California Emergency Management Agency (Cal EMA) will collaborate with CNRA and the seven sector-based Climate Adaptation Working Groups (CAWGs) to assess California's vulnerability to climate change, identify impacts to State assets, and promote climate adaptation/mitigation awareness through the Hazard Mitigation Web Portal and My Hazards website as well as other appropriate sites. The transportation sector CAWG, led by Caltrans,

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and Habitat (BH), Ocean and Coastal Resources (OCR), Water Management (W), Agriculture (A), Forestry (F), Transportation and Energy Infrastructure (TEI), and Cross-Sector (CS).

will specifically assess how transportation nodes are vulnerable and the type of information that will be necessary to assist response to district emergencies. Climate change impacts were recognized in the 2007 State Hazard Mitigation Plan (SHMP) as having an effect on primary hazards such as flooding and wildfires and secondary hazards such as levee failure and landslides. Special attention will be paid to the most vulnerable communities impacted by climate change. (CS-3 and 5; PH-4 and 5; OCR-5; W-4; F-2 and 3; TEI-5, 6 and 8).

7. The State should identify key California land and aquatic habitats from existing research that could change significantly this century due to climate change. Based on this identification the state should develop a plan for expanding existing protected areas or altering land and water management practices to minimize adverse effects from climate change induced phenomena. (BH-1; W-5; F-5).

8. The California Department of Public Health will develop guidance by September 2010 for use by local health departments and other agencies to assess mitigation and adaptation strategies, which include impacts on vulnerable populations and communities and assessment of cumulative health impacts. This includes assessments of land use, housing and transportation proposals that could impact health, GHG emissions, and community resilience for climate change, such as in the 2008 Senate Bill 375 regarding Sustainable Communities. The best long-term strategy to avoid increased health impacts from climate change is to ensure communities are healthy to build resilience to increased spread of disease and temperature increases. (PH-3).

9. Communities with General Plans and Local Coastal Plans should begin when possible to amend their Plans to assess climate change impacts, identify areas most vulnerable to these impacts, and to develop reasonable and rational risk reduction strategies using the Draft California Adaptation Strategy as guidance. Every effort will be made to provide tools to assist in these efforts. (BH-1; OCR– 2 and 4; CS-2).

10. State fire fighting agencies should begin immediately to include climate change impact information into fire program planning to inform future planning efforts. Enhanced wildfire risk from climate change will likely increase public health and safety risks, property damage, fire suppression and emergency response costs to government, watershed and water quality impacts, and vegetation conversions and habitat fragmentation. (PH-4 and 5; F-1; TEI-3).

11. State agencies should meet projected population growth and increased energy demand with greater energy conservation and increased use of renewable energy. Renewable energy supplies should be enhanced through the Desert Renewable Energy Conservation Plan that will protect sensitive habitat that will help reach the state goal of having 33 percent of the state's energy supply from renewable energy by 2020. (TEI-2).

12. Existing and planned climate change research can and should be used for state planning and public outreach purposes; new climate change impact research should be broadened and funded. By September 2010, a user friendly web-based map and interactive website will be developed and regularly updated by the California Energy Commission to synthesize existing California climate change scenario and climate impact research and to encourage its use in a way that is useful for local decision-makers. Every effort will be made to increase funding for climate change research. (CS-4 and 6; PH-7; BH-4; OCR-6; W-8, 9, and 10; A – 8; F-4 and 5; TEI-3 and 9).

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Natural Resources Canada > Earth Sciences Sector > Priorities > Climate Change Impacts and Adaptation

Climate Change Impacts and Adaptation

From Impacts to Adaptation: Canada in a Changing Climate 2007

From Impacts to Adaptation: Canada in a Changing Climate 2007 reflects the advances made in understanding Canada's vulnerability to climate change during the past decade. Through a primarily regional approach, this assessment discusses current and future risks and opportunities that climate change presents to Canada, with a focus on human and managed systems. It is based on a critical analysis of existing knowledge, drawn from the published scientific and technical literature and from expert knowledge. The current state of understanding is presented, and key knowledge gaps are identified. Advances in understanding adaptation, as well as examples of recent and ongoing adaptation initiatives, are highlighted throughout the report.

The assessment team involved experts from across the country, acting as advisory committee members, authors and editors. The completed report consists of eleven chapters.

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Appendix I

the full report, 448 pages.

For further information, please contact adaptation@NRCan.gc.ca.

Date Modified: 2008-11-27

http://adaptation.nrcan.gc.ca/assess/2007/index_e.php

Appendix I

Carbon Tax Rates

The proposed tax rates, effective July 1, 2008, are based on $10 per tonne of carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. CO_2e is the amount of carbon dioxide, methane and nitrous oxide released into the atmosphere, with the non-carbon dioxide emission levels adjusted to a carbon dioxide equivalent basis.

The proposed tax rates will increase over the next four years, based on the dollars per tonne of CO_2e emissions, as set out below:

- July 1, 2009 - $15 per tonne of CO_2e emissions
- July 1, 2010 - $20 per tonne of CO_2e emissions
- July 1, 2011 - $25 per tonne of CO_2e emissions
- July 1, 2012 - $30 per tonne of CO_2e emissions

The specific tax rates will vary for each type of fuel, depending on the amount of CO_2e released as a result of its combustion. For example, at $10 per tonne, the tax on gasoline would be 2.41 cents per litre and for diesel, 2.76 cents per litre.

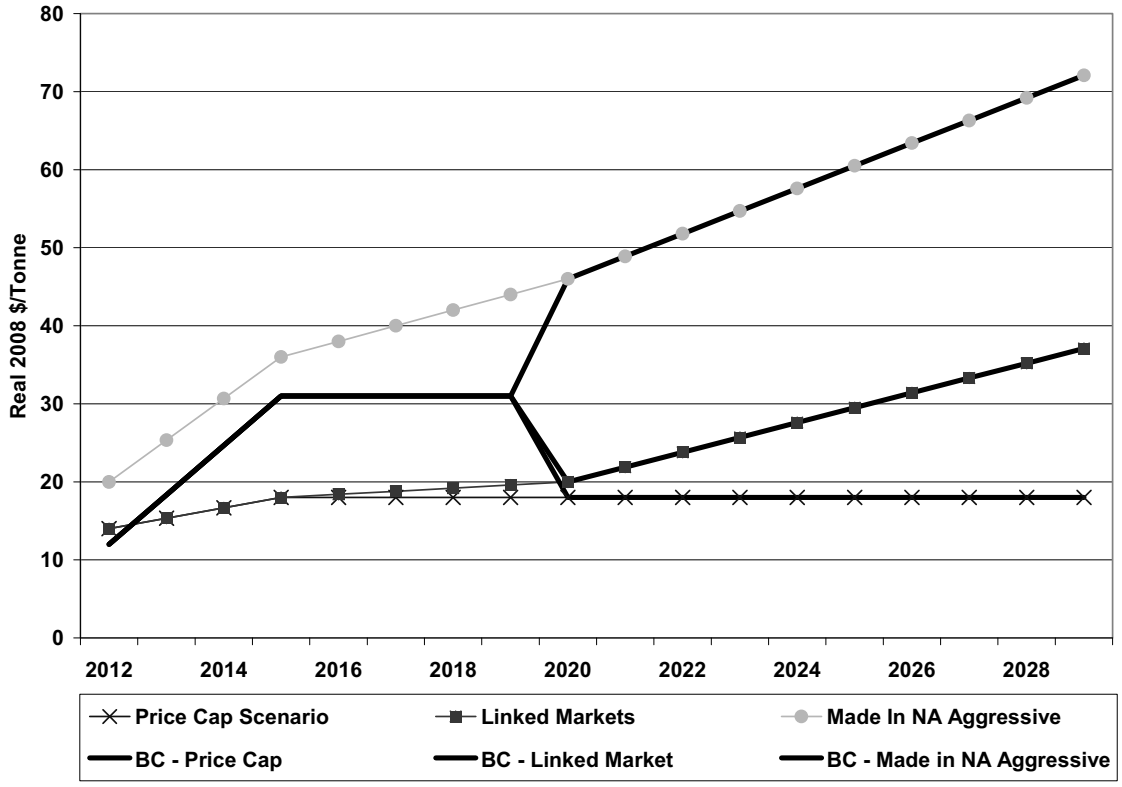
The following table lists the fossil fuels that are expected to be subject to the carbon tax and the proposed carbon tax rate for each type of fuel.

Carbon Tax Rates by Fuel Type

	Units for Tax Rates	July 1 2008	July 1 2009	July 1 2010	July 1 2011	July 1 2012
Liquid Fuels						
Gasoline	¢/Litre	2.41	3.62	4.82	6.03	7.24
Diesel	¢/Litre	2.76	4.14	5.52	6.89	8.27
Light Fuel Oil	¢/Litre	2.76	4.14	5.52	6.89	8.27
Heavy Fuel Oil	¢/Litre	3.11	4.67	6.22	7.78	9.33
Aviation Gasoline	¢/Litre	2.45	3.67	4.90	6.12	7.34
Jet Fuel	¢/Litre	2.62	3.93	5.25	6.56	7.87
Kerosene	¢/Litre	2.56	3.84	5.12	6.40	7.68
Gaseous Fuel						
Natural Gas	¢/GJ*	49.88	74.82	99.76	124.70	149.64
Propane	¢/Litre	1.53	2.30	3.06	3.83	4.60
Butane	¢/Litre	1.76	2.65	3.53	4.41	5.29
Ethane	¢/Litre	0.98	1.46	1.95	2.44	2.93
Pentane	¢/Litre	1.76	2.65	3.53	4.41	5.29
Coke Oven Gas	¢/GJ*	42.31	63.47	84.62	105.78	126.93

Figure presents both the broader planning scenarios as well as the scenarios that would relate to B.C. until the GHG offset markets link. The methodology of how the GHG price forecast is incorporated is described in Chapter 5.

Figure 4-1 GHG Offset Cost Scenarios in Portfolio Analysis



4.2.4.2 Accounting for Indirect Impacts of GHG Regulations

In addition to the direct impacts identified above, there is an indirect impact of GHG regulations for utilities' resource planning environment through the scenario forecasts of natural gas and electricity market prices. This impact is described in the following sections on natural gas and electricity markets that follow.

Table 3 – Price Estimates for Three Planning Scenarios

Price Estimates for Planning Scenarios[91] (CDN $2008)								
Year		2010	2012	2015	2020	2030	2040	2050
Price Cap Scenario		$14	$14	$18	$18	$18	$18	$18
Linked Markets Scenario	Price Range	n.a.	Canada: $14 U.S.: $12-18	Canada: $18 U.S.: $11-17 [92]	$15-25	$24-54	$39-59	$63-97
	Mid Point		Canada: $14 U.S.: $15	Canada: $18 U.S.: $14	$20	$39	$49	$80
Made in North America Aggressive Targets Scenario	Price Range	n.a.	$16-24	$24-47	$35-57	$65-84	$112-124	$166-187
	Mid Point		$20	$36	$46	$75	$118	$177

1. Price Cap Scenario

- In this scenario, Canada and U.S. remain outside of an international agreement and implement less ambitious but what appear to be politically feasible policies (regional and state/provincial initiatives except California's are superseded by federal regulations);
- Prices presented in Table 3 are prices in Canada based on the price cap under the current proposed Federal Regulatory Framework. No economic models were used to estimate prices for this scenario.
- The program proposed by the Government of Canada specifies price cap values through 2017.[93] For purposes of this Price Cap scenario, we assume the price cap continues through 2050 (it increases based on the rate of nominal GDP growth

[91] In 2012, only one pricing estimate was available in each of the Linked Markets and the Made in North America Climate Champions scenarios. In each case when only a single numerical result from a model is available, the range is calculated based on +/-20% of the model pricing estimate.

[92] The price range in 2015 ($11-17) is lower than the price range in 2012 ($12-18). This result is counter-intuitive, and can be explained as follows. There is only one price estimate available for 2012 ($15). To provide a range, we adjusted that estimate by +/-20% resulting in $12-18 in 2012. In contrast, there were several model estimates available in 2015, ranging from $11 to $17, which we did not adjust by a factor of +/-20%. (Note that the study providing the $11 estimate in 2015 did not provide an estimate for 2012.)

[93] The price cap in the Regulatory Framework for Canada is derived from the allowable contributions by industrial emitters to a Technology Development Fund. There are two components to the fund – a technology deployment component that ramps down to near zero in 2017 and a technology research fund for which there is no specified sunset. In the Price Cap scenario, we assume that there is sufficient pressure brought to bear on the federal government to agree on an indefinite continuation of both components of the Fund through to 2050 or alternatively the creation of another price cap vehicle.

Table 7: Summary of GHG Cost Adders[117]

Entity	Process	GHG Adder Range[118] (CDN$2008/tonne of CO_2e)	Timeframe of Analysis for GHG Adders
PacifiCorp	IRP (2007)[119]	$0 - $69.60	2007-2026
Northwestern Energy	RPP (2005)[120]	$6.50 - $36.93	2010-2025
Puget Sound Energy	IRP (2007)[121]	$7.19 - $48.97	2012-2027
Idaho Power Company	IRP (2006)[122]	$0 - $60.06	2006-2025
Avista Utilities	IRP (2007)[123]	$0 - $41.57	2015-2027
Portland General Electric	IRP (2007)[124]	$8.36 - $69.19	2010-2027
Seattle City Light	IRP (2006)[125]	$6.01 - $101.16	2006-2026
Tri-State	IRP (2007)[126]	$11.71 - $43.65	2007-2026
Colorado Springs	IRP (2007, Draft)[127]	$0-$108.26	2010-2027
Southern California Edison	LTPP (2006)[128]	$10.22	2007-2016

[117] Original prices were converted to January 1, 2008 CDN dollars per metric ton (tonne) of CO_2e as follows. Prices per short ton were converted into prices per tonne based on 1 short ton = 0.9072 metric tons. Next, prices were converted to US $2007 based on Consumer Price Index (CPI) data from the Bureau of Labor Statistics (BLS) of the U.S. Department of Labor. Specifically, prices expressed in terms of future year dollars (2008 and beyond) were converted into $2007 using a discount factor equal to the average inflation rate over the past 10 years, approximately 2.66% (http://data.bls.gov/cgi-bin/cpicalc.pl). Prices expressed in past year dollars (prior to 2007) were converted into US $2007 using historical annual inflation rates based on "CPI -All Urban Consumers 1982-84=100 - CUUR0000SA0" data series (http://www.bls.gov/cpi/home.htm). Subsequently, adder prices were converted into $CDN using an exchange rate of US $1 = CDN $1.05 obtained from www.xe.com on July 20, 2007. Lastly, prices were converted to 2008 CDN dollars based on the Bank of Canada's CPI projections for the 3rd and 4th quarter of 2007 (http://www.bankofcanada.ca/en/mpr/pdf/update120707.pdf).

[118] These ranges include all GHG values assumed over time in each IRP/LTTP. As the table illustrates, the specific timeframe of analysis considered in each IRP/LTTP differs (see discussion in subsection A of this section for additional detail on this and other assumptions).

[119] PacifiCorp 2007 Integrated Resource Plan, http://www.pacificorp.com/File/File74765.pdf

[120] NorthWestern Energy's 2005 Electric Default Resource Procurement Plan, http://www.montanaenergyforum.com/plan.html

[121] Puget Sound Energy 2007 Integrated Resource Plan, http://www.pse.com/energyEnvironment/pse2007irpView.aspx

[122] Idaho Power Company's 2006 IRP, http://www.idahopower.com/pdfs/energycenter/irp/2006/2006_IRP.pdf

[123] Avista's 2007 Electric Integrated Resource Plan, http://www.avistautilities.com/resources/plans/electric.asp

[124] Portland General Electric 2007 Integrated Resource Plan, http://www.portlandgeneral.com/about_pge/current_issues/energy_strategy/pge_irp_2007.pdf

[125] Seattle City Light 2006 Integrated Resource Plan, http://www.seattle.gov/light/news/issues/irp/docs/SCLIRP2006.pdf

[126] Tri-State Generation 2007 Integrated Resource Plan, http://www.tristategt.org/NewsCenter/NewsItems/Tri-State%20IRP%2002-15-2007.pdf

[127] Colorado Springs 2007 Electric Integrated Resources Plan Presentation, April 20, 2007 http://www.csu.org/about/projects/eirp/participation/13744.pdf

Canadian Federal program and the U.S. in 2012-15. To reiterate, the Linked Markets scenario assumes that the current Canadian Federal GHG program, including the price cap, continues through 2015, and a U.S. federal program with targets consistent with a 550 ppmv global concentration target (e.g. S. 280) begins in 2012.

Starting in 2020, estimated prices in all jurisdictions are those associated with the Linked Markets scenario. This scenario appears to be the most likely scenario among those considered in this analysis starting in 2020, subject to the caveats and conditions discussed in Sections III and IV and other significant uncertainties. By 2020, it appears that BC would harmonize its approach with the Canadian Federal Government, and WCI/WECC states would adopt the U.S. Federal Government's GHG targets. Different requirements at the state and Federal level will be difficult to maintain over time, given the added cost burden and compliance complexity that this would impose on the private sector and the likely opposition of companies that own and operate assets in states with more stringent targets and GHG policies or that have differing targets and GHG policies.

Table 8: GHG Price Estimates for Policy Scenarios Assessed to be Most Likely in 2012-15 and 2020-50

Year	2012	2015	2020	2030	2040	2050
Most Likely Policy Scenario	WCI/WECC Compliance Instruments Only		Linked Markets Scenario			
BC Price Ranges (all prices CDN$2008/tonne CO_2e)	$9-14	$16-46	$15-25	$24-54	$39-59	$63-97
BC Mid-Point	$12	$31	$20	$39	$49	$80
Canadian Federal Program (intensity target and price cap through 2015) Price Ranges	$14	$18	$15-25	$24-54	$39-59	$63-97
Canadian Mid-Point	$14	$18	$20	$39	$49	$80

U.S. Federal Program (McCain-Lieberman or similar in 2012) Price Ranges	$12-18	$11-17[191]	$15-25	$24-54	$39-59	$63-97
U.S. Mid-Point	$15	$14	$20	$39	$49	$80

[191] The price range in 2015 ($11-17) is lower than the price range in 2012 ($12-18). This result is counter-intuitive, and can be explained as follows. There is only one price estimate available for 2012 ($15). To provide a range, we adjusted that estimate by +/-20% resulting in $12-18 in 2012. In contrast, there were several model estimates available in 2015, ranging from $11 to $17, which we did not adjust by a factor of +/-20%. (Note that the study providing the $11 estimate in 2015 did not provide an estimate for 2012.)

BC HYDRO LONG -TERM ACQUISITION PLAN JUNE 2008

TESTIMONY OF DR. MARK JACCARD

ON BEHALF OF THE
INDEPENDENT POWER PRODUCERS ASSOCIATION OF B.C.

Among other things, I am a member of the National Round Table on the Environment and the Economy. In my view if the Government of Canada is to reach its goal of long-term (2050) national emission reduction targets for greenhouse gas (GHG) the required emission prices for CO2e are likely to be in the range suggested by the table below:

Table ES 1: Greenhouse gas price simulated in this report ($2005 / tonne CO_2e)

	2011-2015	*2016-2020*	*2021-2025*	*2026-2030*	*2031-2035*	*2036-2040*	*2041-2045*	*2046-2050*
Greenhouse Gas Price	$15	$115	$215	$300	$300	$300	$300	$300

My view is based on the attached report entitled "Draft Report Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy; A Sectoral and Regional Analysis" dated July 1, 2008 which was prepared by J&C Nyboer for the National Round Table on the Environment and the Economy.

HIGHER CARBON PRICES WITH FRAGMENTED POLICY ACROSS JURISDICTIONS

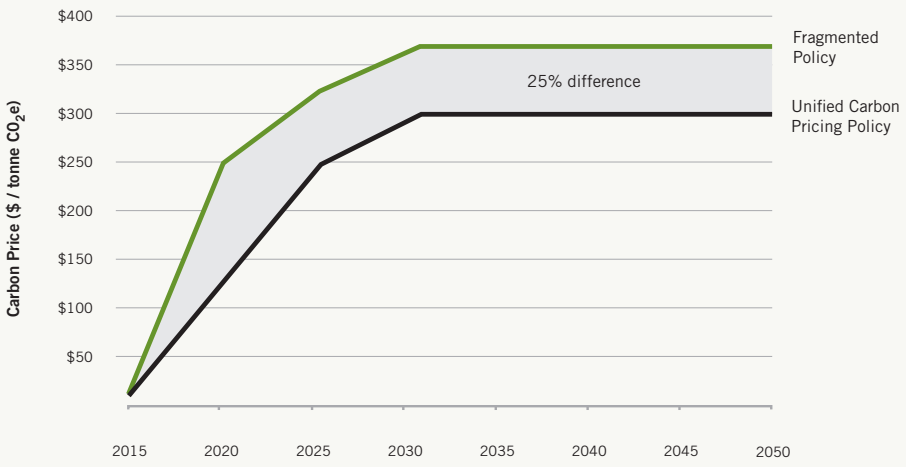


FIGURE 5

Unify carbon prices through a single national cap-and-trade system

The central design question for carbon pricing policy is the choice of a pricing policy instrument. At the outset, the NRTEE determined that in designing an effective carbon pricing policy we would not simply choose between the two principal instruments: carbon taxes and cap-and-trade systems. Each offers a benefit that carbon pricing policy seeks: price certainty through carbon taxes, emissions reduction certainty through cap-and-trade. Put another way, one offers *price-setting* certainty, the other offers *quantity-setting* certainty. In reality, price-setting approaches (taxes) can be blended with quantity-setting approaches (cap-and-trade) as we manage the trade-offs between the two. Figure 6 is a notional illustration of how existing and proposed carbon pricing instruments in Canada are neither a "pure" carbon tax nor a "pure" cap-and-trade system; rather, they blend aspects of one another to deliver on goals of price and emissions quantity certainty.

THE RAPIDLY RISING DOMESTIC COSTS OF ABATEMENT

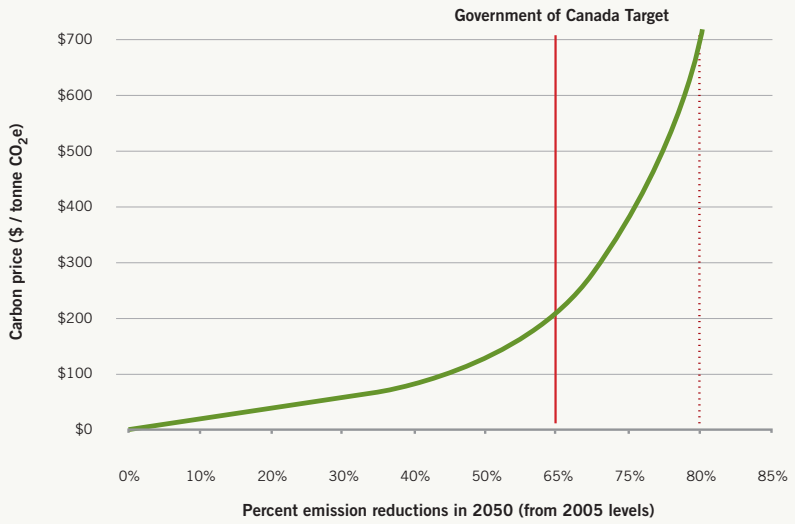


FIGURE 7

COST-EFFECTIVENESS COMPARISON BETWEEN DOMESTIC-ALONE VS. INTERNATIONAL TRADING AND PURCHASES

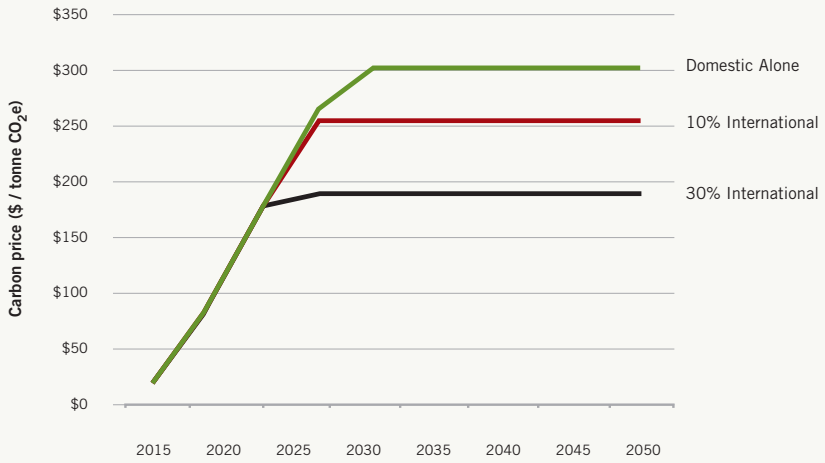
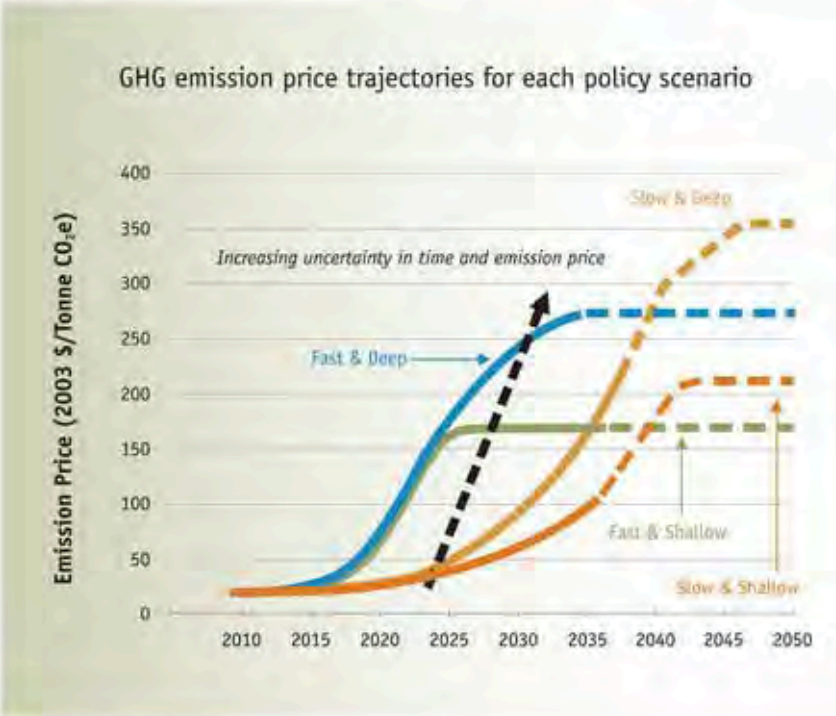


FIGURE 8

influenced by international emission prices and market conditions. Hence the prices are depicted as dotted lines in Figure 3 at higher levels and further into the future.

Figure 3: GHG emission price trajectories for each policy scenario



Note: See Section 5.5 for the key scenario assumptions in CIMS, including starting energy prices for natural gas, electricity, coal, gasoline, oil and other refined petroleum products.

Pathway Trade-offs

The NRTEE research demonstrates that the choice of pathway to a low-GHG emission future involves trade-offs between environmental objectives and economic outcomes, as is illustrated in Figures 2 and 3. Clearly there is a potential for greater economic cost (in terms of $/tonne CO_2e) associated with deeper (65%) GHG emission reductions. In considering these trade-offs, the NRTEE found that any delay in abatement action sooner rather than later could lead to three specific risks:

- not attaining deep emission reduction targets;
- higher economic costs; and,
- higher cumulative GHG emissions.

and increased to \$200/t CO_2e by 2020 would still result in emissions that are slightly higher than target currently promoted by ENGOs.

Throughout the rest of this report, emission prices refer to the values in 2020. The trajectory of prices leading up to 2020 is assumed in the general equilibrium modelling but not referred to directly.

Due to modelling limitations and time constraints, the carbon price path to 2020 outlined in this report does not take into account any complementary measures or the purchase of international carbon credits. This exclusion means that the carbon prices reported here are higher than might be required in practice, if accompanied by other measures.

TABLE 2
Optimal Price Path to Achieve GHG Targets in 2020 – Path that Minimizes GDP Loss (some industrial fugitive emissions only)

CARBON PRICE PATH TO 2020 (2003\$/T CO_2e)			EMISSION REDUCTION IN 2020 RELATIVE TO:		
2010	2015	2020	1990	2006	2020 BAU
\$25	\$45	**\$75**	+10%	-12%	**-21%**
\$40	\$65	**\$100**	+1%	-19%	**-27%**
\$55	\$90	**\$150**	-12%	-30%	**-35%**
\$75	\$130	**\$200**	-19%	-35%	**-40%**

Source: Reduced form model of CIMS (minimize GDP loss to achieve target reduction)

ASSESSMENT OF REVENUE USE OPTIONS

This report investigates how alternative mechanisms for carbon price revenue utilization might change the economic impact of carbon pricing. Some of the revenue utilization schemes analyzed here are revenue neutral, while others are not. In this report, we use the term revenue neutrality in reference to revenue from a specific source, rather than overall government revenue. For example, if the revenue raised from carbon pricing were used to lower the personal income tax rate, revenue neutrality (as defined in this report) implies that the revenue from the carbon price would exactly make up for the shortfall in revenue caused by reduction in the income tax rate. Because of other feedbacks in the economy however, government collection of other taxes may change, leaving overall government revenue changed.

Six alternative tax shifting and revenue recycling options are examined:[30]

- **Lump-sum recycling to households** (**LUMPSUM**). In this scenario, all emission price revenue is collected by government and then totally disbursed as rebates to households. In this scenario, both government revenue and expenditures (transfers) increase relative to business as usual. This scheme therefore, is net revenue neutral, after accounting for government transfers to households. In this report, the LUMPSUM scenario is treated as a comparison benchmark for all other scenarios.
- **Recycling to industrial emitters based on output** (**production**) (**OUTPUT**). In this scenario, all emission price revenue is returned to firms proportionately to their economic output.[31] This recycling scheme provides an incentive for firms to increase output if they can do so without substantially increasing emissions. As a result, it should provide a stimulus to economic growth. Like the previous scenario, this one sees both government revenue and expenditures (transfers) increase relative to the business as usual case. Again, we consider the scheme net revenue neutral, since it involves transfers by government to firms but no increase in government expenditures;

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for the Approval of a Net Metering Rate Schedule 95

BEFORE: P.E. Vivian, Commissioner
A.A. Rhodes, Commissioner July 29, 2009

O R D E R

WHEREAS:

A. On April 17, 2009, FortisBC Inc. ("FortisBC") submitted an application (the "Application") to the British Columbia Utilities Commission (the "Commission") for approval of a Net Metering Rate Schedule 95 and resulting revisions to the FortisBC Electric Tariff Index and Rate Schedule 80; and

B. FortisBC proposed the Net Metering Rate Schedule in response to the Provincial Energy Plan, the *Utilities Commission Act* section 64.01, Commission Order G!117!05 and stakeholder requests; and

C. On April 28, 2009, the Commission issued Order G!43!09 establishing a written hearing process to review the Application; and

D. In accordance with Order G!43!09, a written regulatory process was conducted from May 22, 2009 to July 6, 2009. Commission and Intervenor Information Requests were received on May 27, 2009. FortisBC responded to Information Requests by June 10, 2009; and

E. FortisBC made its Final Submission on June 17, 2009, Intervenor Final Submissions were received on June 19, 2009, and FortisBC's Reply Submission was received on July 6, 2009; and

F. The Commission has reviewed the Application, the responses to Information Requests and the Submissions of FortisBC and the participating Intervenors.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the FortisBC Net Metering program as proposed in the Application with the modifications described in the Reasons for Decision accompanying this Order.

2. The Net Metering program may commence subsequent to approval by the Commission of a revised FortisBC Net Metering Tariff ! Rate Schedule 95 which incorporates the directives described in the Reasons for Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of July 2009.

BY ORDER

Original signed by:

P.E. Vivian
Commissioner

Attachment

FortisBC Inc.
Net Metering Program

REASONS FOR DECISION

GENERAL APPROVAL

The Commission Panel generally approves the FortisBC Net Metering Tariff Application as filed. Prior to implementation, the Commission Panel directs FortisBC to incorporate the directives and determinations, as discussed in these Reasons, into the program.

Net Metering!Monitoring and Evaluation Report	Required
Existing Electro!Mechanical Meters	Acceptable
Rate Schedule 95 (Net Metering)	Modifications
Site Inspections Provisions	Modified
Reconciliation Costs	Modified

NET METERING-MONITORING AND EVALUATION REPORT

The Commission Panel directs FortisBC to file a Net Metering!Monitoring and Evaluation Report (the "Report"). The Report should contain information similar in nature to that required for the BC Hydro Net Metering program (Commission Order G!26!04, Appendix A, Section 2.6). FortisBC should file the Report with the Commission within 60 days of the anniversary date of program commencement.

The Commission Panel agrees with the Okanagan Environmental Industry Alliance (the "Alliance") and the B.C. Sustainable Energy Association and the Sierra Club of British Columbia ("BCSEA") that having FortisBC produce and file a report similar to BC Hydro's will provide a more complete picture of the progress of net metering in the province. The collected reports will contribute to future net metering policy development.

The BC Hydro report must contain information on net metering activities in other jurisdictions. For the FortisBC Report, that effort need not be replicated. Instead, the Report should be limited to descriptions and data on FortisBC program penetration, costs and recommended future changes. As FortisBC offers Time!of!Use pricing, the Report should address net metering program results for customers on regular rates as compared to those under Time!of!Use rates. FortisBC should also make recommendations for amendments to the Net Metering program that it deems necessary. The Commission will provide FortisBC with additional guidance on specific content closer to the due date, if requested.

ELECTRO-MECHANICAL METERS

The Application does not allow for the use of standard electro!mechanical meters, spinning in both directions, to measure energy exchange. (Exhibit B!1, p. 11) Instead, FortisBC proposes that a customer!generator be connected through a single meter, with separate registers for each flow direction. The Commission Panel considers that the evidence does not support ruling out the use of existing, electro!mechanical meters.

As part of a response to an information request, FortisBC supplied Measurement Canada Information Bulletin 2007!04!20. The Bulletin describes Measurement Canada's policy on the use of electro!mechanical meters in net metering applications. Among other details, the Bulletin states that electro!mechanical meters may be inaccurate in favour of the utility:

> "MC has performed a study on the effect of operating electro!mechanical meters in the reverse direction. This study indicated that at low currents, the accuracy trend of electro! mechanical meters taken from a small sample of meters tested shows the errors to be in favour of the contractor. The report included results showing that some errors at low currents may be as high as 8% slow." (Exhibit B!2, BCUC Appendix 8.1, p. 3)

Bulletin 2007!04!20 specifies that electro!mechanical meters may be used for net metering until the earlier of either the replacement of the existing meter or December 31, 2013. Measurement Canada allows electro! mechanical meters in net metering applications. (Exhibit B!2, BCUC Appendix 8.1, Section 7)

FortisBC gave no indication in either the Application or responses to information requests that there is a safety reason why electro!mechanical meters cannot be used.

The Commission Panel anticipates that, further to the Advanced Metering Decision and Order G!168!08, FortisBC will be bringing forward a plan to generally replace existing meters with advanced meters in the relatively near future. In order to decrease the likelihood of making two meter replacements, existing, electro!mechanical meters should not be precluded from use in Net Metering.

The Commission Panel considers that electro!mechanical meter inaccuracy should be balanced against the cost to the customer of replacing existing meters. Allowing customers the option of using existing, electro! mechanical meters should improve the economics of the program.

The Commission Panel therefore directs FortisBC to provide customers with the option of using existing electro! mechanical meters for Net Metering, subject to the requirements of Measurement Canada Information Bulletin 2007!04!20, Section 7.2.

RATE SCHEDULE 95 – AMENDMENTS

The proposed Net Metering Rate Schedule 95 does not sufficiently describe two matters that the Commission Panel considers should be clarified for the benefit of potential customer!generators.

First, the terms "facility" and "Generating Facility" are used in proposed Rate Schedule 95. The Commission Panel considers that clear definitions of these terms are required. The proposed Rate Schedule 95 instead defines "Net Metered System." The BC Hydro Net Metering Service Rate Schedule (RS1289) (copy attached as Appendix 1) may be used as a guide for the definitions. Therefore, the Commission Panel directs FortisBC to submit a revised Rate Schedule 95 that includes definitions for "facility" and "Generating Facility" as applicable to the Net Metering program.

Second, the proposed Rate Schedule 95 does not clearly describe General Liability provisions. The Net Metering program poses potential negligence issues that are beyond what would commonly confront a residential customer. Therefore, the Commission Panel directs FortisBC to include in Rate Schedule 95, a more explicit description of the proposed general liability provisions as they relate to the utility and the Net Metering customer!generators. The description should include specific information regarding the exposure of each of the utility and the customer!generator to negligence and consequential damages.

PROPOSED INSPECTION PROVISIONS AND THE SAFETY STANDARDS ACT

The Application indicates that a site inspection may be required prior to interconnection. As proposed, site inspections could apply to cases where FortisBC has concerns over the nature of the installation, either for safety reasons or for adherence to interconnection standards.

The Commission Panel agrees that a customer!generator must follow FortisBC interconnection requirements. However, the Commission Panel considers that, while FortisBC may elect to conduct a site safety inspection, as it is not inherently a utility function, a fee should not be charged to the customer.

The *Safety Standards Act* establishes installation, inspection, and operating requirements applicable to facilities downstream of the utility meter. If a customer can demonstrate to FortisBC that its facility has been properly certified under the *Safety Standards Act*, the Commission Panel is not persuaded that a FortisBC inspection is required. Production of required certifications issued under the *Safety Standards Act* should obviate the need for further inspection costs which only serve to adversely affect the economics of net metering.

The Commission Panel notes and agrees with the comments of Intervenor Resolution Electric: "Considering an electrical permit from the BC Safety Authority would be required to perform the installation work at a cost of approximately $670 for a 2.5kW Photo Voltaic system it could be questioned what value there is in performing the inspection by two different inspection bodies, with a potential cost of $1160." (Resolution Electric, Final Submission, p. 1)

The Commission Panel determines that a FortisBC inspection may be appropriate where Fortis BC is not satisfied with the customer!generator's documentation or certificate or is otherwise concerned that the customer! generator's facility poses safety or system problems. However, such inspection, if considered necessary by FortisBC, shall be for the account of FortisBC. In the event that any FortisBC inspection discovers a safety deficiency, FortisBC is to follow good utility practice and may decline to proceed with the net metering connection.

RECONCILIATION COSTS

The Application presents $160 as the expected, annual cost of reconciling customer!generator accounts. The Commission Panel considers that FortisBC should use actual, incremental net metering program reconciliation costs in any financial report, rather than applying the proposed rate of $160.

The Commission asked FortisBC to comment whether a customer!generator recording a credit balance would create a $160 reconciliation cost. In response, FortisBC stated that "The reconciliation cost is lower if the credit balance is carried over since a cheque does not have to be issued to the customer. The $160 is an estimated average cost for reconciling both customers that request a refund and those that carry their credit balances over. The cost differential is approximately $50." (Exhibit B!2, BCUC 1.10.1) The Commission Panel expects the

reconciliations associated with the program to not require expenses beyond those commonly needed for a non!net metering account. There is no evidence that the proposed metering creates a complicated calculation justifying an incremental cost of $160.

Intervenors also noted the expected reconciliation cost. In a letter to FortisBC dated March 30, 2009, Resolution Electric noted and questioned the magnitude of the expected reconciliation costs. (Exhibit B!1, p. 20)

The Commission Panel directs FortisBC to record any incremental costs incurred for net metering account reconciliation during the first 12 months of the program. FortisBC is to include a summary of the costs as a section in its Net Metering–Monitoring and Evaluation Report.

INTERVENOR ARGUMENTS

The Commission Panel is not persuaded by the Alliance arguments that the payback period should be lessened by incentive pricing. The Province has yet to give direction to the Commission requiring net metering programs to contain incentive pricing. Consistent with the recent Commission decision on the BC Hydro net metering program, an incentive price component is not required as a condition of approval at this time:

> The Province has not yet issued a directive to the Commission with respect to incentive pricing and the specific role of the Net Metering program in achieving conservation objectives. Until the time that such a directive is issued, the Commission cannot presume the details of potential Government policy. The Commission is therefore not persuaded that it should order BC Hydro to include an incentive component into the Net Metering price at this time. (Commission Order G!4!09)

The Alliance proposes that Government or Commission policy should be released requiring an incentive component to net metering programs. The Commission, as per the BC Hydro Decision excerpt above, does not establish such policy.

The Alliance proposes that FortisBC should include a report of world!wide programs that offer incentive premiums as part of net metering. (Alliance Final Submission, Section 3) The Commission Panel considers that, as BC Hydro has been directed to update external net metering programs as part of its reporting requirements, there is no need for FortisBC to duplicate that effort. Nonetheless, the Commission Panel expects FortisBC to keep abreast of external net metering program attributes that could be beneficially applied to its service area in the future.

The existing FortisBC Tariff includes a Time!of!Use pricing option. A Commission information request asked whether, in FortisBC's view, the combination of the proposed Net Metering program and the Time!of!Use rate class constituted a price incentive.

> "The existence of Time!of!Use rates does constitute an incentive for participation in the Net Metering program, compared to BC Hydro's program. On!peak rates for residential Time!of!Use are 15.9 cents per kWh in summer and 16.522 cents per kWh in winter, compared to 7.46 cents for non Time!of!Use residential rates. Although FortisBC's summer peak is growing more rapidly than its winter peak, the Company does not consider that further incentives for participation are required, particularly given the expected size of installations under the Net Metering program." (Exhibit B!2, BCUC 1.19.1)

The Commission Panel accepts FortisBC's response that the combination of net metering and Time!of!Use pricing forms an acceptable incentive to participate in the net metering program. A customer on the Time!of!Use pricing would have a shorter payback period, and therefore a greater incentive to participate in net metering.

The Final Submissions of the other registered Intervenors indicated support for the proposed Net Metering program without condition.

FINAL APPROVAL

The Commission Panel expects to grant final approval for the FortisBC Net Metering program subsequent to FortisBC filing the appropriate Tariff pages containing the revisions necessary to comply with the above determinations and directives, and a finding by the Commission Panel that the requirements described in these Reasons are satisfied.

APPENDIX 1

BC HYDRO – RATE SCHEDULE 1289 NET METERING SERVICE

SCHEDULE 1289 - NET METERING SERVICE

Definitions

"Generating Facility" for purposes of this Rate Schedule means a generating facility that:

(a) Utilizes water, wind, solar, fuel cell, geothermal, biogas, biomass, municipal solid waste, cogeneration or other energy resources or technologies meeting the requirements of the Province of British Columbia's definition of "BC Clean Electricity" to generate electricity;

(b) Has a nameplate rating of not more than fifty (50) kilowatts; and

(c) Is owned by the Customer and is located on the same parcel of land as the Customer's Premises for which service .is being provided under any of the Rate Schedules listed above, or on an adjacent parcel of land owned or leased by the Customer, and is connected to the same Point of Delivery as the Customer's Premises being served under any of the Rate Schedules listed above;

and includes all wiring, protection!isolation devices, disconnect switches, and other equipment and facilities on the Customer's side of the Point of Delivery.

Metering

1. Inflows of electricity from the BC Hydro system to the Customer, and outflows of electricity from the Customer's Generating Facility to the BC Hydro system, will normally be determined by means of a single meter capable of measuring flows of electricity in both directions.

2. Alternatively, if BC Hydro determines that flows of electricity in both directions cannot be reliably determined by a single meter, or that dual metering will be more cost!effective, BC Hydro may require that separate meters be installed to measure inflows and outflows of electricity.

3. The Customer shall install, at its cost, the meter base and any wiring, protection!isolation devices, disconnect switches, and other equipment and facilities on the Customer's side of the Point of Delivery as required under BC Hydro's "Net Metering Interconnection Requirements, 50 kW and Below". BC Hydro will supply and install the meter or meters and make the final connections.

4. Any meters or meters required for purposes of this Rate Schedule shall be in addition to any demand meters (if applicable) required under the Rate Schedule under which the Customer is receiving service from BC Hydro.

Special Conditions

6. If BC Hydro in its discretion deems it necessary to require the Customer to interrupt or disconnect its Generating Facility from BC Hydro's system, or for BC Hydro to itself effect the interruption or disconnection of the Generating Facility from its system, as provided in the Net Metering Interconnection Agreement, or as a result of the suspension or termination of service to the Customer in accordance with Special Condition 3 above, then except to the extent caused by the wilful misconduct or gross negligence of BC Hydro, its servants or agents, BC Hydro and its servants or agents shall not be liable to the Customer for any loss or damage whatsoever resulting from such interruption or disconnection.

December 6, 2008
By Paul Gipe

Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments

What Are Feed-in Tariffs?

Feed-in tariffs are payments, or tariffs, for renewably-generated electricity. They are paid to the producer for every kilowatt-hour of electricity they generate.

Why Are They important?

Feed-in tariffs are a powerful policy mechanism that has produced rapid growth of renewable energy in Europe, especially in Germany, France, and Spain. Equally as important, feed-in tariffs are more egalitarian than other policy mechanism and have allowed people from all walks of life to participate in the renewable energy revolution—for profit.

Why Should We Use Feed-in Tariffs?

Systems of feed-in tariffs have been highly successful at developing large amounts of geographically dispersed renewable sources of generation quickly, at low cost and with minimal administration. And because feed-in tariffs are not dependent upon the tax status of the owner, they are available to everyone who wants to use them.

What are Advanced Renewable Tariffs?

Advanced Renewable Tariffs are a comprehensive system of feed-in tariffs that are differentiated by technology, project size, application, and in the case of wind energy by resource intensity. Advanced Renewable Tariffs are the modern version of the simpler feed-in tariffs that were used previously in Denmark and Germany.

Where Have Feed-in Tariffs Been Used Successfully?

Feed-in tariffs are widely used in continental Europe. Advanced Renewable Tariffs are prominently used in Germany, France, Spain, and Switzerland. Germany and Spain have become worldwide leaders in renewable energy because of their sophisticated systems of Advanced Renewable Tariffs.

Where are Feed-in Tariffs Being Used Now in North America?

Ontario, Canada, and California have implemented simplified systems of feed-in tariffs. Both jurisdictions are in the process (2009) of greatly expanding their programs.

Why are there So Many Different Names for Feed-in Tariffs?

Feed-in tariffs have been most successfully used in continental Europe and there is no single best English translation of the terms used in Germany, France, or Spain. The term “feed-in tariff” is a literal translation from Germany’s 1991 *Stromeinspeisungsgesetz* (StrEG), the law on feeding electricity into the grid.

North Americans have attempted several adaptations using “payments” instead of using the term “tariffs” as tariffs sometimes has a negative connotation in North American English. These coinages have resulted in Renewable Energy Payments and Renewable Energy Producer Payments.

The term “feed-in tariff” itself doesn’t capture the sophistication of the system of feed-in tariffs used in Europe. For this reason, renewable energy advocates in Ontario, Canada coined the expression Advanced Renewable Tariffs to convey the modern system of feed-in tariffs that are differentiated by technology, size, application, and resource intensity.

Sometimes feed-in tariffs and Advanced Renewable Tariffs are shortened to simply “renewable tariffs.”

Occasionally feed-in tariffs are incorrectly referred to as Standard Offer Contracts. This is especially true in North America. Systems of Advanced Renewable Tariffs rely on “Standard Contracts” but specifically do not use “Standard Offers.” In systems of Advanced Renewable Tariffs, the “offers” differ by technology, size, application, and resource intensity and are thus are not “standard.”

In Ontario, Canada, the program of feed-in tariffs is formally called the Standard Offer Contract Program. However, the Minister of Energy had directed staff to produce a program of standard contracts, not standard offers. The ruling party had previously endorsed the expression Advanced Renewable Tariffs.

Are Feed-in Tariffs the Same as Tax Credits?

No. Feed-in tariffs are simply payments for generation. They have nothing to do with taxes or subsidies. Thus, feed-in tariffs are more egalitarian because they allow everyone to be paid for their electricity even those who do not pay a lot in taxes.

Are Feed-in Tariffs Just Another Subsidy?

Feed-in tariffs are not subsidies. They do not subsidize the cost of the equipment used to produce renewably-generated electricity, like solar panels or wind turbines, nor do the payments come from taxpayers. Instead, feed-in tariffs are simply payment for the generation of electricity. Society decides whether it wants a certain form of renewable energy, then it decides what it costs to pay for it. That's all there is to it. Some technologies, such as solar photovoltaics, cost more than other technologies and, thus, they must be paid more for their electricity than, say, the electricity from wind turbines.

Are Tariffs Taxes?

Tariffs are the rate paid for commodities like electricity. Electricity tariffs are the price paid per kilowatt-hour of electricity consumed, or in this case, generated. The term is commonly used in North America's electric utility industry. The term is also commonly used in Europe. Tariffs are not taxes nor in this context customs duties on goods crossing international borders.

Who Pays for Feed-in Tariffs?

Consumers of electricity pay for feed-in tariffs through charges on their electric bills just like they do now for electricity from conventional power plants. This is more equitable than paying through taxes because consumers who use a lot of electricity will pay more for renewable generation than those who use less. There are also programs in most states and provinces that protect low-income consumers from paying high prices for their electricity, especially during the winter months.

How Much Do Feed-in Tariffs Cost Consumers?

Very little at first because it takes several years for renewable sources of generation to become a significant part of electricity supply. Even in places such as Germany and Spain the additional cost of renewable energy is modest because the costs are spread fairly across all consumers. In Germany in 2007, the average household paid outright less than $50 per year for the world's largest concentration of wind turbines, solar panels, and biomass plants, and the 250,000 new jobs these industries have created. The German government estimates that the actual cost is near zero, because the benefits in reducing carbon emissions and other air pollutants, as well as offsetting the cost of expensive fossil-fired generation offsets the cost of the renewable energy.

Do Feed-in Tariffs Allow You to Sell Back to the Grid?

No. Feed-in tariffs allow you to "sell" to the grid, not "sell back" to the grid. There's an important difference. Selling "back" to the grid implies that you are already buying from the grid, that is, you are a customer and already have a

kilowatt-hour meter. In such cases as net metering, the potential of the program is limited by the amount “consumed” by the utility customer. Feed-in tariffs allow you to generate electricity and sell it to the grid even if you are not presently a customer. Feed-in tariffs allow the development of green-field sites, such as the installation of wind turbines in a field that are owned by groups of neighborhood investors, cooperative, or traditional business.

How Do We Know That Feed-in Tariffs Will Work?

Like any policy mechanism, feed-in tariffs can be misapplied. The most common problem is setting the prices, the tariffs, too low and not attracting the desired amount of development. Another common problem is setting a limit on project size, or a limit that is far too low, or setting a limit on program size that is too low to allow ample industrial capacity to develop. These problems have been encountered in programs that were timidly implemented because proponents were not serious about dramatically increasing the supply of renewable generation. However, where there was serious political commitment for the programs to succeed they have done so as seen especially in Germany, France, and Spain.

How Do Feed-in Tariffs Differ from Net Metering?

Net metering is a policy that allows you to produce some of your own electricity when you can, store excess on the grid when you produce more than you need—effectively running your kilowatt-hour meter backwards--and taking the electricity you “stored” on the grid when you need it. With net metering, you can never produce more electricity than you consume

In contrast, feed-in tariffs pay for the delivery of electricity to the grid. To use feed-in tariffs, you need a kilowatt-hour meter that measures the delivery of electricity for sale to the grid. The electricity is not “stored” on the grid, rather it is “sold” to the grid for a profit. Thus, you are not selling “back” to the grid, you are “selling to” the grid.

In Australia, some forms of net metering are incorrectly called feed-in tariffs. Thus, in Australia, true feed-in tariffs are called “gross” feed-in tariffs because all the electricity is sold to the grid.

Will Feed-in Tariffs Allow “Double Dipping” into State Rebate or Subsidy Programs?

Feed-in tariffs are designed to provide sufficient financial incentive to develop renewable energy without capital grants, rebates, or other capital subsidies. Thus, in most states or provinces where they have been proposed, those who opt for feed-in tariffs can not also use capital grants or rebates.

However, in the United States the federal Investment Tax Credit for solar systems and small wind turbines has been extended for eight years. As a consequence, most feed-in tariff programs proposed in the USA will include provisions for using the federal ITC alongside the feed-in tariff.

Can Feed-in Tariffs Work in Parallel with Existing Programs?

Yes, the feed-in tariff programs proposed in North America have all been designed to work alongside and in parallel to existing policies, such as net metering and renewable energy standards.

How Do Feed-in Tariffs Enable Distributed Generation?

The tariffs or prices in systems of Advanced Renewable Tariffs are designed to encourage development of renewable projects of all sizes, from residential rooftop to farms of large wind turbines, and in all locations, from sunny and windy sites to those sites less well endowed with wind and solar resources. When well designed, these differentiated tariffs result in the geographical distribution of renewable development and in the distribution of technologies in numerous different applications. While feed-in tariffs are also used to develop centralized renewable sources of generation, they are best known for increasing the role of distributed renewable resources.

What Renewable Energy Sources Are Included?

In systems of Advanced Renewable Tariffs, where the tariffs are differentiated by technology, programs can be designed to include all renewable sources of generation or only those that society wants in a particular jurisdiction. Some jurisdictions may want to use feed-in tariffs only for solar, or only for wind. Others, such as Germany, France, and Spain have tariffs for a host of different technologies, including onshore and offshore wind energy, rooftop and ground-mounted solar systems, hydro, various forms of biomass and biogas, geothermal electricity generation, and concentrating solar power.

How Are the Tariffs Calculated?

The tariffs are determined through a transparent political process based in input from industry, independent consultants, and users among others. In systems of Advanced Renewable Tariffs, prices are based on the cost of generating electricity with a specific renewable technology under specific conditions, plus a reasonable profit. In the successful programs, for example in Germany, France, and Spain, the tariffs are not determined by the cost of the conventional generation the renewable sources offset. In this way, the tariffs are not only high enough to spur development, but not so high that they create excessive profits.

Do Feed-in Tariffs Eliminate Environmental Review?

No. Projects using feed-in tariffs must comply with the same laws and environment requirements as any other projects. Feed-in tariffs typically only apply to the mechanism for getting access to the grid, for selling electricity to the grid, and the price that is paid for the electricity.

What Are the Key Elements of Advanced Renewable Tariffs.

Successful programs of Advanced Renewable Tariffs must

- Be simple, comprehensible, and transparent,
- Provide simplified interconnection,
- Provide sufficient price per kilowatt-hour to drive development,
- Provide contract length sufficient to reward investment, and
- Provide tariffs differentiated by technology, size, and resource intensity.

Does PURPA Prohibit Feed-in Tariffs in the US?

No. PURPA, the Federal Public Utility Regulatory Policies Act (1978), regulates only qualified facilities, or QFs. States retain jurisdiction to regulate electricity rates and special programs for developing renewable energy. For example, Renewable Energy Credit (RECs) trading programs created as part of a state Renewable Portfolio Standard (RPS) are permitted by the Federal Energy Regulatory Commission under PURPA. So to would be any special program that paid tariffs above the “wholesale” price specified under PURPA. Independent power producers would have no need to register as “qualified facilities” under PURPA if there was a program of Advanced Renewable Tariffs that guaranteed access to the grid and paid higher prices than those under PURPA contracts.

Currently, several states have feed-in tariffs and two states, Washington and Wisconsin, have tariffs that pay more than the PURPA defined “wholesale” rate. Washington has a special net-metering program that pays up to $0.54/kWh for five years for generation from solar photovoltaics (PV) components that were assembled in the state. This tariff is well above the wholesale cost in the Pacific Northwest. Several utilities in Wisconsin also pay special incentive rates for small solar, wind, and biomass generators that are above the wholesale cost of generation.

What are Degression Rates?

In some systems of Advanced Renewable Tariffs, the tariff offered for new projects declines annually from one year to the next at a fixed rate. Degression differs from the regular, scheduled review of tariffs that occurs in all programs. Degression rates, in percent, are based on the expectation that the cost of generation will decrease as the technology advances "down the learning curve." As such, degression assumes that the cost of the technology declines from one year to the next or it is intended to force development along this path. Unfortunately, the cost of generation from a particular technology doesn't always decline. Sometimes, as in the case of wind energy during the period 2006 to 2008, the cost of generation actually increased from one year to the next. For more on this topic, see Degression of Renewable Tariffs.

Are Feed-in Tariffs Adjusted for Inflation?

Yes. In many programs there are adjustments in the tariff or payment with respect to an index of inflation. This varies from program to program. There is no inflation protection in the German program, but there is in the French and Spanish programs. For more on this topic, see Inflation Adjustment of Renewable Tariffs.

Is Legislation Required to Implement Feed-in Tariffs?

In some states, provinces, and municipalities, feed-in tariffs can be implemented administratively. Most municipalities with their own municipal utilities have the authority to implement feed-in tariffs directly. In others legislation maybe required.

What Can I Do to Put Feed-in Tariffs on the Policy Agenda in North America?

During 2008, the grassroots movement for feed-in tariffs in North America has blossomed from a few committed individuals to groups active across Canada and the United States. If you would like to help, contact the Alliance for Renewable Energy and ask if there is a group active in your area. Contact your local, regional, and federal elected representatives and ask them to support introduction of legislation implementing systems of Advanced Renewable Tariffs.

Where Can I Find More Information on Feed-in Tariffs?

There are several web sites that feature news and articles about feed-in tariffs. The most comprehensive site can be found at http://www.wind-works.org/articles/feed_laws.html. On this page there are links to more detailed information on the following subjects.

- Renewable Tariffs by Country
- Renewable Tariffs in Ontario, Canada

Appendix L

- Renewable Tariff Design
- Model Advanced Renewable Tariff Legislation
- Renewable Tariff Pricing
- Renewable Tariffs Overview
- Tables of Feed-In Tariffs Worldwide
- The Economic Case
- Reviews of Books on Feed-in Tariffs
- Links to More on Feed-in Tariffs

Books on Feed-in Tariffs

There several books with detailed information on feed-in tariffs and renewable tariff policy. You can find information about these books at the links below.

- Feed-in Tariffs by Miguel Mendonca--a Review
- Energy Switch: Proven Solutions for a Renewable Future
- Switching to Renewable Power by Volkmar Lauber

Web Sites on Feed-in Tariffs

There are several web sites that feature articles on feed-in tariffs, renewable tariff design, and news updates on the movement for feed-in tariffs in North America.

- German Experience with its Renewable Energy Sources Act
- European Feed-in Cooperation
- International Feed-in Tariff News Group
- Californians for Feed-in Tariffs News Group
- World Future Council's Feed-in Tariff Pages
- WFC's Feed-in Tariff Design Guide
- The Feed-In Tariff Channel--Audio and video interviews with policy leaders by Marc Strassman (Note: a video player will install on your browser)
- Green Thoughts: Sustainability, Renewable Energy and Marketing by Micheal Hoexter
- Green Energy War: Former California Energy Commisioner John Geesman blogs on global climate and energy politics

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- the Alliance for Renewable Energy: An alliance of policymakers, renewable energy experts, citizens, research institutions, and large and small businesses promoting the use of feed-in tariffs (Renewable Energy Payments) in North America.
- Florida Alliance for Renewable Energy
- Wind-works.org: One of the world's most extensive collection of articles and reports on feed-in tariffs.

-End-

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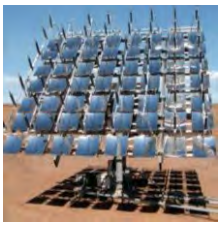
Appendix L

HEINRICH BÖLL STIFTUNG
The Green Political Foundation

THE NEW RULES PROJECT



Feed-in Tariffs in America

Driving the Economy with Renewable Energy Policy that Works

By John Farrell
New Rules Project

April 2009

Appendix M

This project has been made possible by funding from the European Commission.
The European Commission is not responsible for the content of the project.

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http://www.ilsr.org/index.html www.newrules.org

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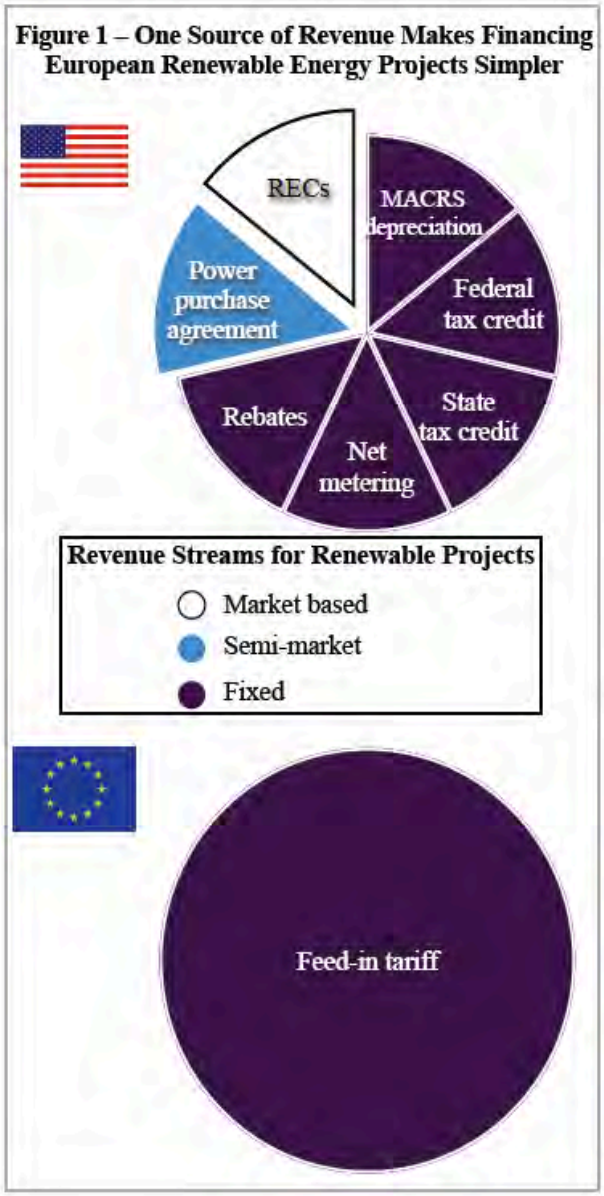
Appendix M

Executive Summary

American renewable energy policy consists of a byzantine mix of tax incentives, rebates, state mandates, and utility programs. The complexity of the system results in more difficult and costly renewable electricity generation, and hampers the ability of states and communities to maximize the benefits of their renewable energy resources.



Evidence from Europe suggests that a simpler, more comprehensive policy achieves greater renewable energy development, but at a lower cost and with greater economic and social benefits like local ownership. It is called a feed-in tariff, a price for renewable energy high enough to attract investors without being so high it generates windfall profits. The tariff can be varied to spur new emerging technologies or to achieve social ends.

Denmark and Germany both used a feed-in tariff to drive renewable electricity generators to more than 15 percent market share. This policy also resulted in large-scale local ownership, with near half of German wind turbines and over 80 percent of Danish ones owned by the residents of the region.

In 2009, one Canadian province (Ontario) and one US municipal utility (Gainesville, FL) have enacted a feed-in tariff. As many as 11 U.S. state legislatures are seriously considering adopting the system as a complement to their renewable electricity mandates. State and federal policy makers should strongly consider turning to a feed-in tariff as the key mechanism for encouraging renewable energy development. It's fairness, simplicity, and stability can help the United States maximize the benefits of the renewable energy revolution.

Feed-in Tariff Success, by the numbers:

- Germany: 15% renewable electricity, 280,000 jobs in the renewable industry, a net benefit of 6 billion Euros per year.
- Denmark: 28% renewable electricity, 21,000 jobs in the wind industry

The Power of Feed-in Tariffs

In the United States, renewable energy policy consists of an uncoordinated and often haphazard combination of state and federal incentives and mandates. A company or person wanting to install a wind turbine or solar electric system must negotiate a bewildering array of incentives (**Figure 1**). Each of the incentives has an overhead cost. Rebates, for example, might require a cumbersome paperwork process. Tax incentives require one to put together a group of profitable corporations with sufficient tax liability to make use of the incentives, and in the process the tax equity investors divert some of that incentive away from the actual project. Having gained sufficient financing, the developer must then engage in lengthy and costly negotiations with the local utility to develop a contract with a price and with often onerous and costly interconnection requirements.

This process impedes the growth of renewable energy, may well raise its cost, and certainly discriminates against small and locally owned projects. It may also undermine states' renewable energy efforts.

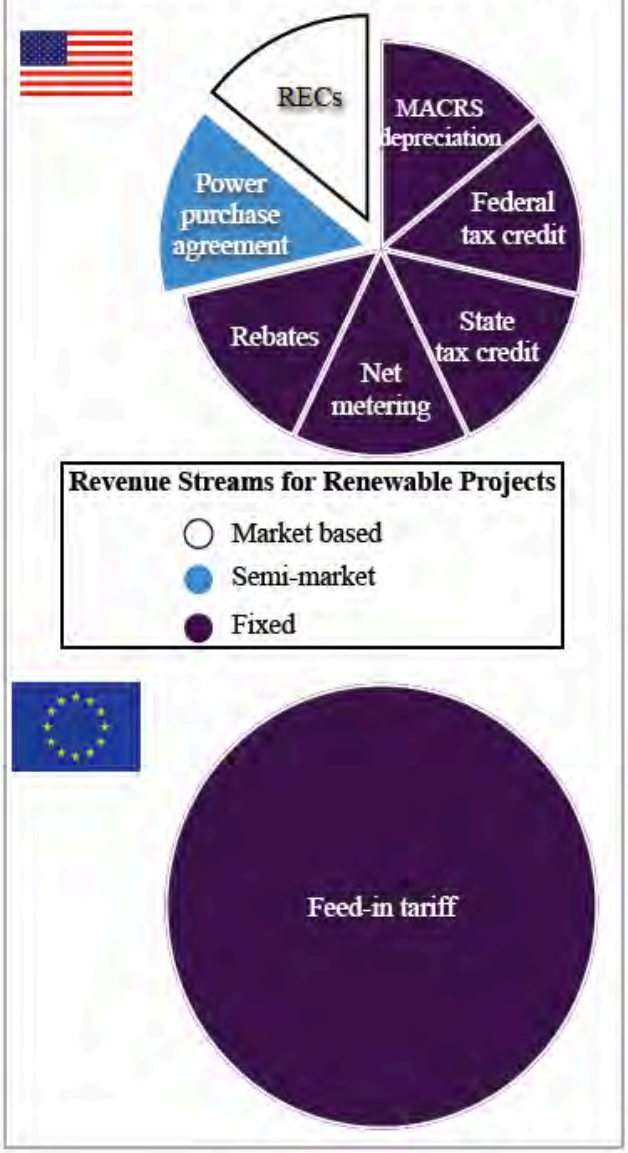
In the last few years, 38 states adopted renewable electricity mandates. These mandate a specific quantity of renewable electricity based on the overall electricity consumption and leave the price up to the "market," a market, as noted, that largely consists of financial incentives. A number of states may be falling behind their interim benchmarks.

Europe has taken a different approach. It has mandated a specific price for renewable electricity and leaves the quantity achieved up to the "market."

In the 1980s and early 1990s, European nations imitated U.S. renewable energy policies (i.e. incentives) and found them ineffective. First Denmark and then Germany, France and Spain adopted a new, simpler policy. They set a price (tariff) sufficient to attract investors.

This policy has several attractive impacts. By establishing a price, it does away with the need for multiple incentives and the financing of projects largely based on their value in reducing tax liabilities. By reviewing the

Figure 1 – One Source of Revenue Makes Financing European Renewable Energy Projects Simpler



price every few years, European states can lower the price if they find that it results in windfall profits and attracts too many renewable energy proposals and raise it if they find it insufficiently attractive. Prices can be varied by technology and scale of production, thereby providing an incentive to emerging technologies and to renewable energy projects that have attractive social or economic impacts (e.g. on site generation, local ownership).

European nations further require utilities to interconnect renewable energy projects on demand. The utilities bear the cost of connecting to higher voltage transmission lines and the utilities must offer a short, uniform contract that includes interconnection requirements.

Empirical studies of the European system have found that it spurs more renewable energy at a lower price than do incentive programs or stand-alone renewable mandates.

> A **Feed-In Tariff** (FIT) provides three key provisions to renewable electricity generators: **a guaranteed grid connection**, a **long term contract**, and a **fixed price** sufficient for a reasonable return on investment.

In Europe this new policy is called a Feed In Tariff. A tariff is the traditional term that describes a utility price structure. Feed-in means that this is a price paid to producers that feed their electricity into the grid system. European nations require that those who accept a feed in tariff must "export" all of their electricity into the grid, unlike many U.S. states that offer **net metering** arrangements whereby the output of a rooftop solar array, for example, would first be used inside the building and spin the meter backwards, with any excess sent into the grid. **Figure 2** illustrates the difference between net metering and a European feed-in tariff for a household with a solar panel, with data in kilowatt-hours (kWh).

Figure 2 (a) – Under <u>net metering</u>, the homeowner uses power to offset domestic use and gets paid at the wholesale rate for excess power

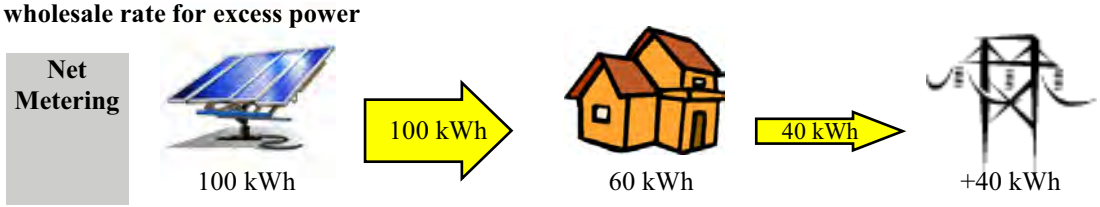
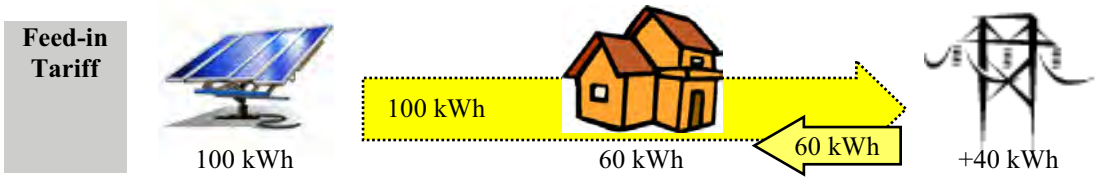


Figure 2 (b) – Under a <u>feed-in tariff</u>, the homeowner sells all their power to the grid for a premium price, but buys all their power from the grid at retail rates



The two policies are really just accounting measures, because the electrons from the solar panel will serve the home first in either case. However, they have a very different impact on the building owner's decision about the size of the renewable energy facility that will be installed. Under net metering, the owner will probably size the unit to the building's internal use, because excess power

is purchased at low (wholesale) rates. Under a feed-in tariff, the producer is paid a premium for every kilowatt-hour generated and there is often no limit on the size of the facility that will earn that payment. The project is an investment – the system will be sized to maximize the rate of return. This could have a significant impact on the economics of rooftop arrays. In the United States a typical photovoltaic (PV) system might cover a third of a roof. Later as PV panel costs decline, the system could be expanded, but because installation is a significant percentage of the overall cost, the second install may offset the lower priced panels. A feed-in tariff that encourages the maximum sized facility to be installed in the first place may lower long term costs.

Outside Europe, feed-in tariffs go by many names: advanced renewable tariffs, renewable energy payments, or feed laws. We prefer to use the name feed-in tariffs (since it's the name used in Europe), although renewable energy payments (REPs) are somewhat more intuitive to the typical American.

This paper presents the case for an American feed-in tariff, based on the European history, the elegance of the policy and the preponderance of evidence that feed-in tariffs generate greater social and economic benefits than alternative policies for the same level of renewable energy deployment.

The European Experience

Two countries in particular provide an illustration of the success of the feed-in tariff: Denmark and Germany.

Denmark: The Rise and Fall of Feed-In Tariffs

Denmark's history of renewable energy policy is one of early commitment, rapid success under a feed-in tariff, and then stagnation from a changed policy. In the 1980s, the Danes were among the first to encourage renewable energy development, a step ahead of many other national efforts to respond to the Arab oil crisis. Their head-start meant that the California wind farms – representing the early renewable energy efforts of the United States in the post oil crisis era – were largely powered by Danish turbines. However, while the U.S. abandoned many of its initiatives as the price of oil fell during the 1980s, the Danes remained committed to their energy independence goals, including the development of renewable energy. A strong anti-nuclear movement also increased the Danish commitment to wind power.[1]

The following timeline illustrates the history of Danish renewable energy policy.

1980s

1979-1992: Fostering a wind industry

In 1979, the Danish legislature (Folketing) introduced the first incentives for wind power, a subsidy for 30 percent of total project costs that decreased over time.[2] Wind power generation first exceeded 100 megawatts (MW) under this proposal, an impressive feat since most were turbines less than 100 kilowatts (kW) in size.

In 1988, the Danes took a step closer to a feed-in tariff, reducing the capital subsidy but requiring utilities to interconnect and purchase power from wind projects. Utilities were also required to provide a "fair price."[3] Wind power capacity increased to near 300 MW.

1990s

By 1992, the "fair price" for wind power was set at 85 percent of the retail electricity rate.[4] The Danes provided guaranteed interconnection and power purchase. The price was still set relative to retail rates and not relative to the cost of production for wind generators.

1993-2002: The FIT and the Surge in Production

In 1993, the Danes formally established a Feed-In Tariff, decoupling the power purchase price from electricity rates. The price paid for power from wind turbines was set at 85 percent of utility production and distribution costs.[5] Wind projects also received a refund of the Danish carbon tax and a partial refund on the energy tax. These refunds effectively doubled the payment to wind projects for the first five years of the project.

In 1998, the price language was changed slightly, though the support level remained largely the same. The new law required utilities to purchase the wind turbine's output at "85 percent of the consumer price of electricity plus ecotax

1990s

relief." These costs were largely borne by the utilities, who received a payment to offset their costs,[6] but turbine operators were responsible for the initial grid connection. "The costs of grid connection are paid by the wind mill owners exactly until the nearest 10 or 20 kV line."[7]

2000s

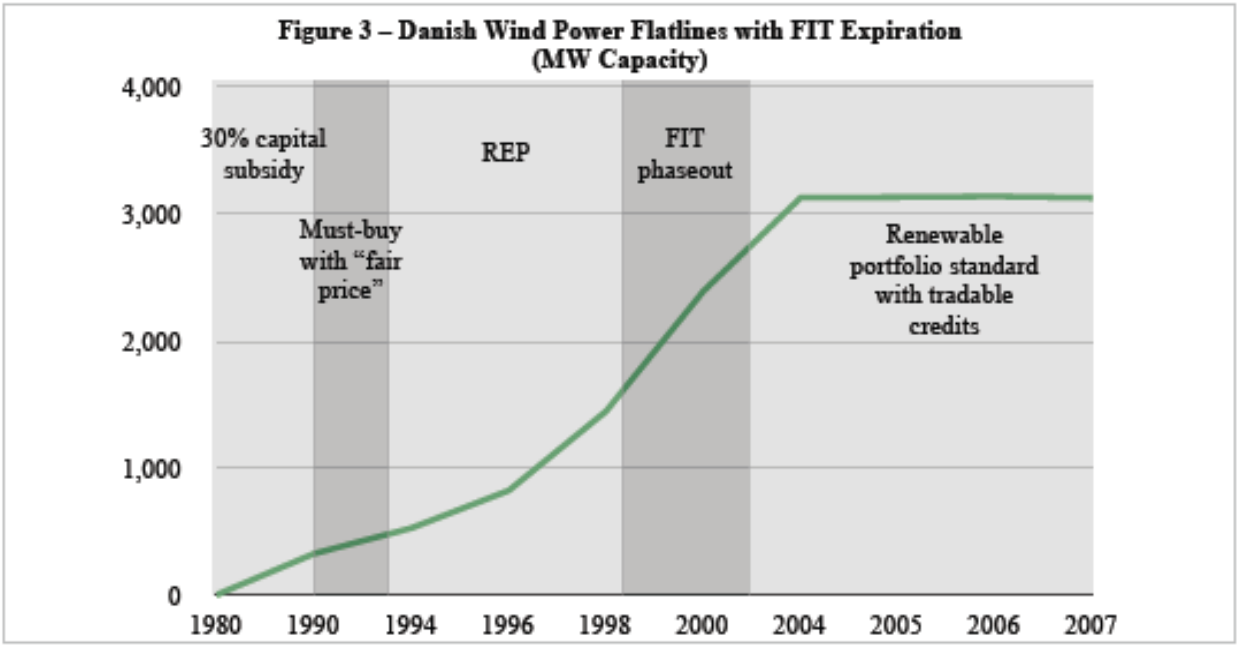
In 1999 the election of a center-right government ended the feed-in tariff in Denmark. Instead, the renewable energy program was changed to an American-style renewable portfolio standard with tradable credits.[8] The new program was phased in, so some producers who came online through 2002 were still able to get the prior tariff rate locked in for 10 years.[9]

2003-Present: U.S.-style quotas and stagnant development

By 2003, all wind generators connecting to the grid had to do so under the new renewable portfolio standard, earning the market price plus a premium. This premium was capped, setting a maximum price that wind producers could receive. The new scheme also no longer guaranteed interconnection. Additions to wind power capacity declined precipitously.[10]

From 1993 to 2004, Danish wind power grew from 500 MW to over 3,000 MW. Since the feed-in tariff was abandoned in 2004, development has stagnated at that level (**Figure 3**).

The new government also offered incentives and a higher payment cap for repowering, making replacement of old turbines more lucrative than adding new wind projects.[11] Developers would remove several small turbines and replace them with one, larger one. The repowering incentives were so lucrative that one wind cooperative sold its turbine for decommissioning in 2005 for the same price it paid in 1988.[12] In 2005, the government responded to stagnating wind development by removing the cap on wind payments, but the net increase in wind power capacity was less than 25 MW between 2004 and 2007.[13]



Danish Results: Energy and Industry

Despite the recent stagnation in wind energy growth, the feed-in tariff's legacy is striking:

- A domestic wind industry with over 20 billion DKK in turnover ($37 billion), employing 21,000 people.[14]
- Denmark gets more electricity from renewables than nearly every other country. In 2007, 28 percent of electricity came from renewable sources,[15] with 20 percent from wind power.[16]
- Over 150,000 families have invested in wind turbines individually or through cooperatives, owning over 80 percent of the country's turbines (with about 60 families per MW).[17]

Denmark: Locally owned wind power

In keeping with a tradition of cooperative ownership in their electricity generation system, the Danes strongly encouraged cooperative ownership of wind projects. The key policy was a tax exemption on revenue from cooperative wind enterprises, a provision that essentially doubled the income from a wind project because of a marginal tax rate close to 50 percent.[18] This exemption dates back to at least 1985 and is a significant reason that cooperatives own over 80 percent of Danish turbines and distribute the revenues to over 150,000 families.

Germany: The Rise and Rise of Feed-In Tariffs

In Germany the motivation for a renewable energy plan was somewhat different than Denmark. Concerns about climate change and environmental degradation motivated the initial commitment to renewable power in the late 1980s, as did an interest in developing a native industry. Later, Green Party participation in the government added an anti-nuclear component to renewable energy policy.

The following timeline illustrates Germany's road to feed-in tariffs.

1990s

1987-1990: A small start

Individual German states offered wind power incentives as early as 1987, when Niedersachsen provided a 50 percent capital subsidy that was phased out by 1995.[19] The federal renewable energy program was started in 1989 with a market stimulation program. It provided a fixed price payment for wind power (with a total budget sufficient for up to 250 MW) and investment incentives for private operators (e.g. farmers) to invest in renewable energy. The program did not yet guarantee interconnection for small producers.[20]

1991-1999: Feed-In Tariff accelerates wind, some solar

In 1991, the Germans adopted feed-in tariffs when they enacted their Electricity Feed-In law. Utilities were required to purchase renewable energy generation and to pay 80 percent of the historical average retail price to producers of qualified renewables.[21] The program was capped at 5 percent of a utility's generation.[22]

In 1999, Germany introduced a parallel incentive for solar PV, known as the 100,000 Roofs Program. It provided zero interest loans and a grant worth 12.5 percent of the system cost. The program ended in 2003 with 346 MW installed across the country.[23]

2000s

2000-Present: Revised FIT broadens German renewable development

In 2000, major revisions were made in the form of the Renewable Energy Act (EEG). This landmark law decoupled feed-in tariff prices from retail rates and instead based prices on the cost of production. There was a guaranteed payment for 20 years and the cap on renewables was removed. The EEG was scheduled for review every two years starting in 2007.[24]

The law also introduced more sophisticated elements to feed-in tariffs, including tariff degression to account for improving technology, stepped tariffs based on the size of a energy producer and the quality of the renewable resource, and set rates separately for wind, solar, and other technologies.[25] The EEG also created the cost-sharing program where the incremental costs of renewable generation are spread among all high-voltage grid operators and end customers.[26]

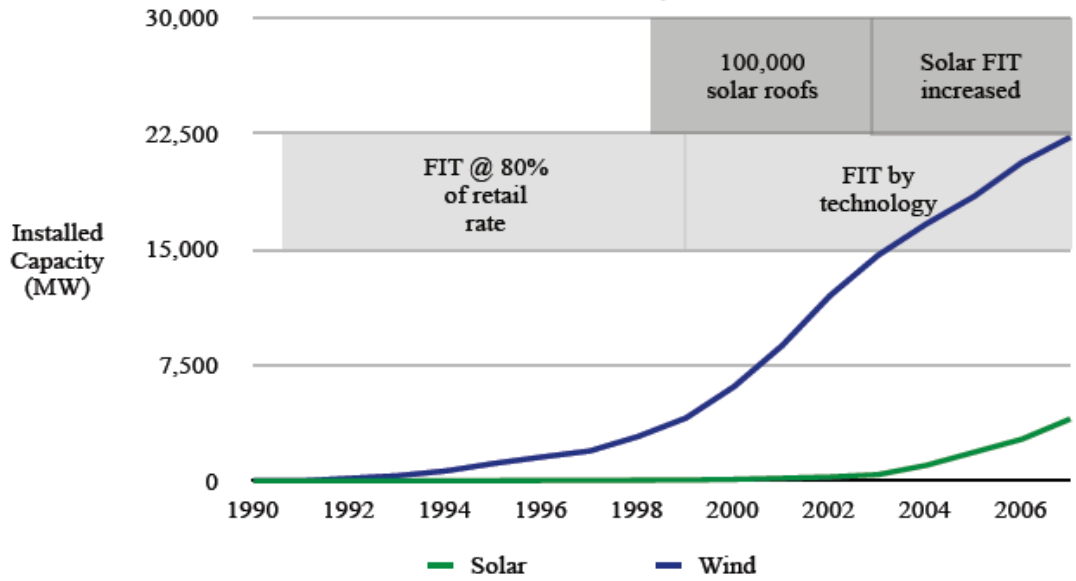
> **Tariff degression** – an annual decrease in the new contract price for a feed-in tariff.
>
> *Example: 5% solar tariff degression*
> - A 2008-installed solar panel gets 60 cents per kWh for 20 years
> - A 2009-installed solar panel gets 57 cents per kWh for 20 years

2000s

In August 2004, the EEG was revised (with support from conservatives), adding firm targets for renewable energy generation and revising tariff prices. Solar PV received a price increase, as did several other technologies, and onshore wind generators saw their tariff decrease.[27] The law also enforced the guaranteed connection and priority access for renewable energy systems.

The result of the German commitment to renewable energy has been a staggering increase in renewable energy production as well as jobs and industry. **Figure 4** illustrates the fruits of Germany's commitment to the feed-in tariff – substantial increases in wind and solar power capacity.[28]

Figure 4 – Feed-In Tariff Turbocharges German Wind and Solar Development



German Results: Energy and Industry

- From 1995 to 2005, Germans increased the share of renewables in their electricity mix from 1 percent to 12 percent.[29] By 2007, Germany received 14 percent of its electricity from renewable sources.[30]
- German renewable energy industries had sales of nearly 11 billion Euro to worldwide customers in 2007 ($15 billion), 44 percent from solar, 21 percent from wind.[31] Germany has 249,000 jobs in renewable energy industries.[32]

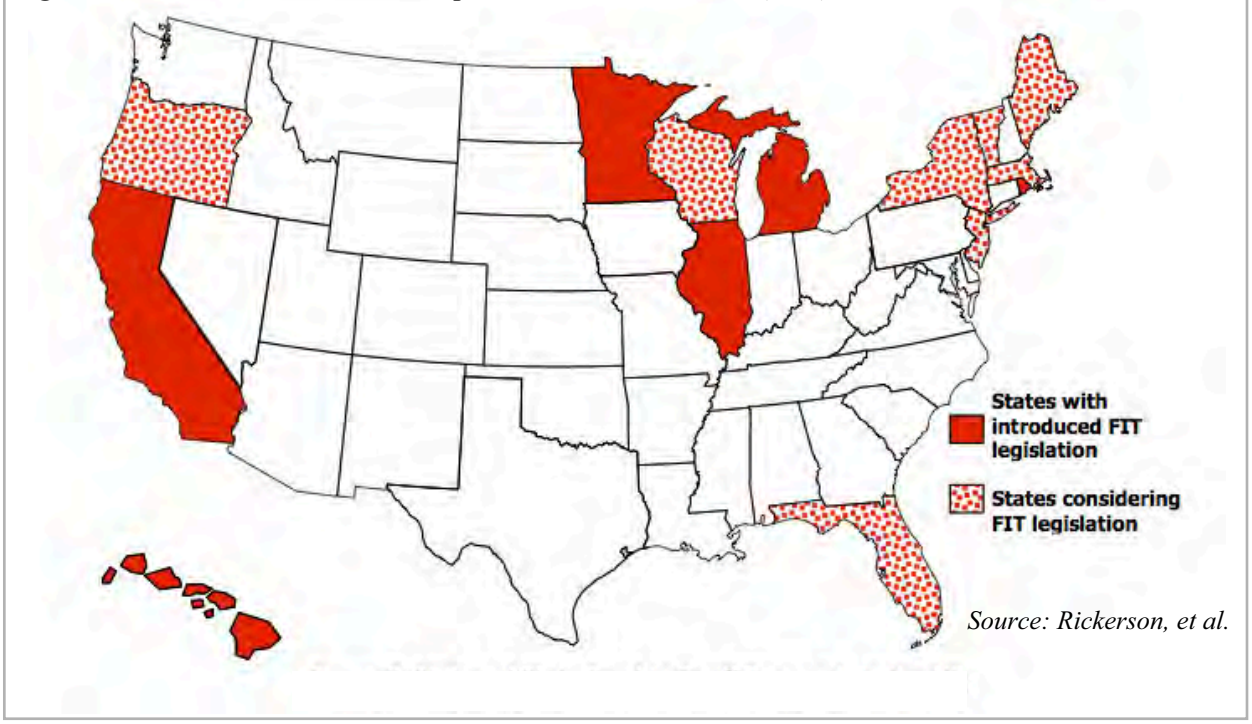
Germany: Locally owned renewable energy

In Germany, high population density and a deep environmental sensitivity encouraged dispersed generation from wind projects and helped enable local ownership. The other factor was the interest of farmers, who helped develop the financing for early wind projects by providing their land as collateral.[33] One-third of Germany's wind power is owned by over 200,000 local landowners and residents.[34]

Feed-In Tariffs in the United States

The stunning success of European policy has encouraged American policy makers to consider feed-in tariffs at the federal, state, and local level. Bills have been introduced in at least eight states to establish feed-in tariffs. Two municipal utilities have proceeded without legislation.[35] Rep. Jay Inslee (D-WA) introduced a bill to encourage nationwide feed-in tariffs in the U.S. House during the summer of 2008.[36] **Figure 5** illustrates the breadth of the feed-in tariff fervor.[37] Since the map was drawn, at least two other states (Iowa and Indiana) have been added to the list.

Figure 5 – Status of Feed-in Tariff Proposals in the United States (2008)



Thirty years ago, the United States briefly flirted with feed-in tariffs after the federal Public Utility Regulatory Policies Act (PURPA)[38] policy ended the utility monopoly on electricity generation, requiring them to buy electricity from independent producers at a price based on their avoided costs. In the early 1980s California required utilities to offer a standard 10 year contract with a high fixed price for wind energy that was in essence a feed-in tariff. The standard offer contracts were abandoned in the early 1990s as California opted to pursue retail electricity deregulation.

> We need to get something on the table that allows community projects to get financed, move ahead, and not get bogged down in all the B.S. that's involved in large power generation.
>
> *–Dan Juhl, community wind developer, Minnesota*

The contrast between the U.S. and Europe is stark. In the U.S. a producer must juggle periodically expiring incentives, 50 independent renewable energy markets, hard-to-use tax credits, and complex and protracted negotiations with utilities over contracts nearly a hundred pages long.

Wind developer Dan Juhl described the U.S. situation at a recent conference on feed-in tariffs in Minnesota, pointing out the many challenges for community-based wind projects.[39] Getting a project on the grid begins with a utility's request for proposal, and a community-based developer bases their project preparation – price quotes for turbines and installation, and other parts of the wind project – on the utility's timeline. The utility usually advertises a particular date for the selection of the winning bid. But once the developer wins the bid process, they begin the power purchase agreement negotiation. Dan noted,

> "It takes a year...[there are] land mines in the power contract...You have to negotiate them out or you will not get financing."

By the time the power purchase contract is negotiated, the community-based developer may be required to renegotiate purchase agreements with suppliers since so much time has elapsed. The entire project is jeopardized. Dan sees a need for legislation to simplify the process:

> "We need to get something on the table that allows community projects to get financed, move ahead, and not get bogged down in all the BS that's involved in large power generation."

Power purchase contracts in the U.S. can be very complex and lengthy. In Germany, a producer gets a 20-year, all-in-one contract that ensures a reasonable profit. The contract is five pages long.[40]

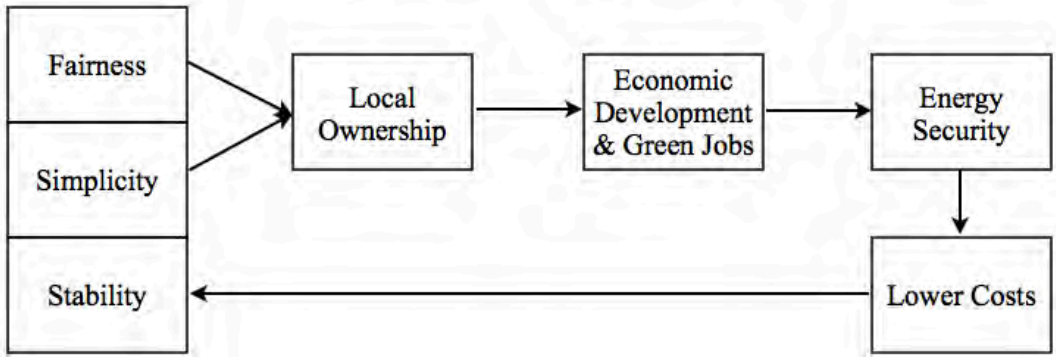
European renewable energy leaders were driven by more than environmentalism – they wanted to capture the economic benefits and green jobs from their renewable energy development. FITs created a vast, competitive market for renewable energy production by creating a truly level playing field for development. With prices set for reasonable cost recovery and profit, a producer need not rely on attracting the relatively few individuals or corporations with large amounts of tax liability (like in the U.S.). The opportunities for ownership were dramatically broadened.

The result of this market democratization was significant. In Germany, 45 percent of wind projects are locally owned. In Denmark, 83 percent of wind projects are owned by individuals or local cooperatives.[41] And for each of these locally owned projects, more of the investment dollar stays in the community and country, creating a cycle of more investment and jobs.

Why Feed-In Tariffs Work

A feed-in tariff incorporates three basic principles for increasing renewable energy generation: fairness, simplicity, and stability (**Figure 6**). Policies based on these principles tend to achieve three goals: a) much broader and dispersed ownership of renewable energy; b) economic development and c) energy security. Evidence from countries with FITs shows that it often achieves these benefits at a lower cost than alternative renewable energy incentives.[42]

Figure 6 - Basic principles of a Feed-in Tariff



Simplicity

A feed-in tariff makes generating renewable energy simple. If you build a renewable electricity generator, you'll get paid one specific price for every kilowatt-hour you produce. Prices are set to guarantee a reasonable rate of return, encouraging further development and more potential owners.

> **Consider the Paper Trail**
> A typical American power purchase agreement between a producer and the utility is 85 pages. In Germany, the contract is 2-4 pages.

Figure 7 (page 17) illustrates how someone interested in renewable energy is compensated under a feed-in tariff, and how this contrasts with the status quo in the United States.

In contrast to existing incentives like the federal production tax credit, with a FIT there's no negotiating with utilities, partnering with tax-credit-hungry investors, or uncertainties about Congress.

Stability

A feed-in tariff makes the market stable. Utilities must connect renewable generators and buy their electricity at the incentive rates for 20 years.

Contrast the FIT with the existing system, where federal incentives can expire, creating boom-and-bust cycles in the market. This stability is a significant reason that Denmark and Germany generate more than 15 percent of their electricity from renewable energy, while the U.S. achieved only 3 percent in 2007.[43]

Fairness

A feed-in tariff makes the market fairer because it removes the barriers to participation from a number of players. A FIT allows people with little tax liability or non-taxable entities – cities, counties, states, non-profits – to pursue renewable energy projects.

Most current U.S. incentives are in the form of tax credits, which are only valuable to individuals or businesses with a lot of tax liability. This unfair system reduces the pool of potential renewable energy investors and dollars, to everyone's detriment.

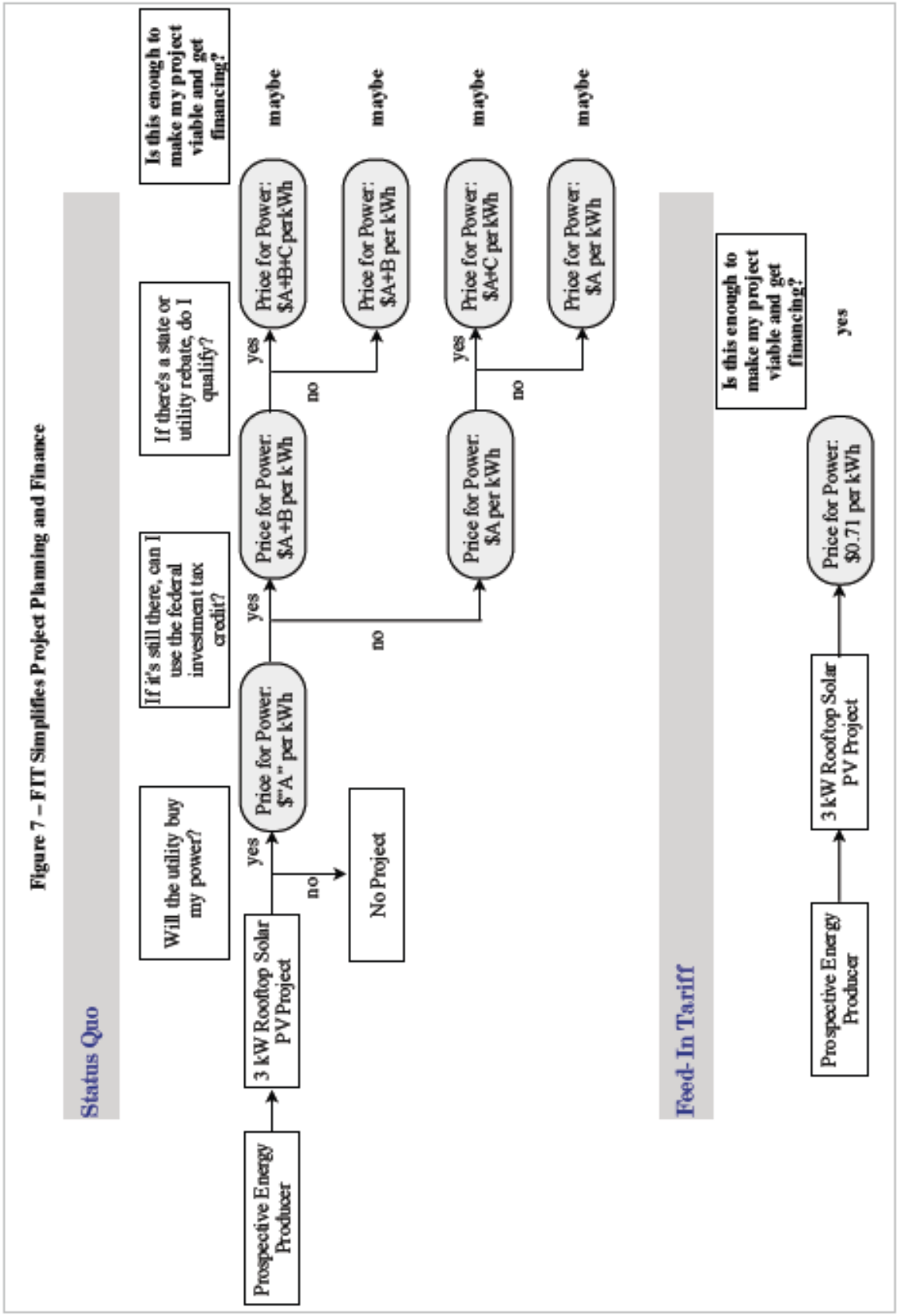


Figure 7 – FIT Simplifies Project Planning and Finance

Appendix M

Designing a Feed-In Tariff

There is no one-size-fits-all feed-in tariff policy. There are many variations as policymakers adapt the core design to their local context and needs.

Setting FIT Rates

Figure 9 (page 20) illustrates the price setting process for a feed-in tariff that supports solar PV, biomass, and wind electricity generation. The following step-by-step process corresponds to the steps on the chart.

1. Offer a reasonable return

Utility investments in regulated states typically receive a guaranteed 10-12 percent return on investment. Feed-In Tariffs are often set to provide a 8-10 percent internal rate of return. This strategy is used in Germany and in a proposed national FIT for the United States (Renewable Energy Jobs and Security Act of 2008).[44] Spain and a few other countries also set a FIT as a premium over retail electricity rates.

2. Configure by technology

Feed-In Tariffs encourage multi-technology investment in order to accelerate the technological learning curve and achieve manufacturing economies of scale. Since costs to generate electricity differ for solar, wind and biomass, payments are adjusted accordingly to encourage a diversity of renewable energy technologies and industries.

3. Award innovation

Some feed-in tariff plans are designed to foster innovation and to achieve social goals. For example, solar on rooftops instead of fields preserves open space and turns shelter into power generation. Placing solar panels on building facades helps increase a building's self-sufficiency. FIT rates can increase for these technologies to encourage their development.

4. Accommodate various sizes

In order to encourage a diversity of dispersed renewable generators, FIT rates are often slightly higher for smaller projects. For example, this may encourage development of wind power projects in areas with lower wind speeds, but greater available transmission capacity.

Adjusting FIT Rates

5. Adjust for experience

FIT prices for new projects often decrease each year to reflect improving technology.

6. Adjust for inflation

Though technological investment reduces costs, even wind and solar are subject to the prices of basic commodities like steel, concrete or silicon. FIT prices can be adjusted to help cover inflation.

7. Provide a long-term contract

A feed-in tariff guarantees a long-term purchase contract for electricity to help investors recover their investment. Renewable energy projects like wind and solar have no fuel costs, so their entire investment is up front. Long term contracts, generally 20 years, ensure that energy producers recover their costs and help them secure financing.

8. Share the Cost

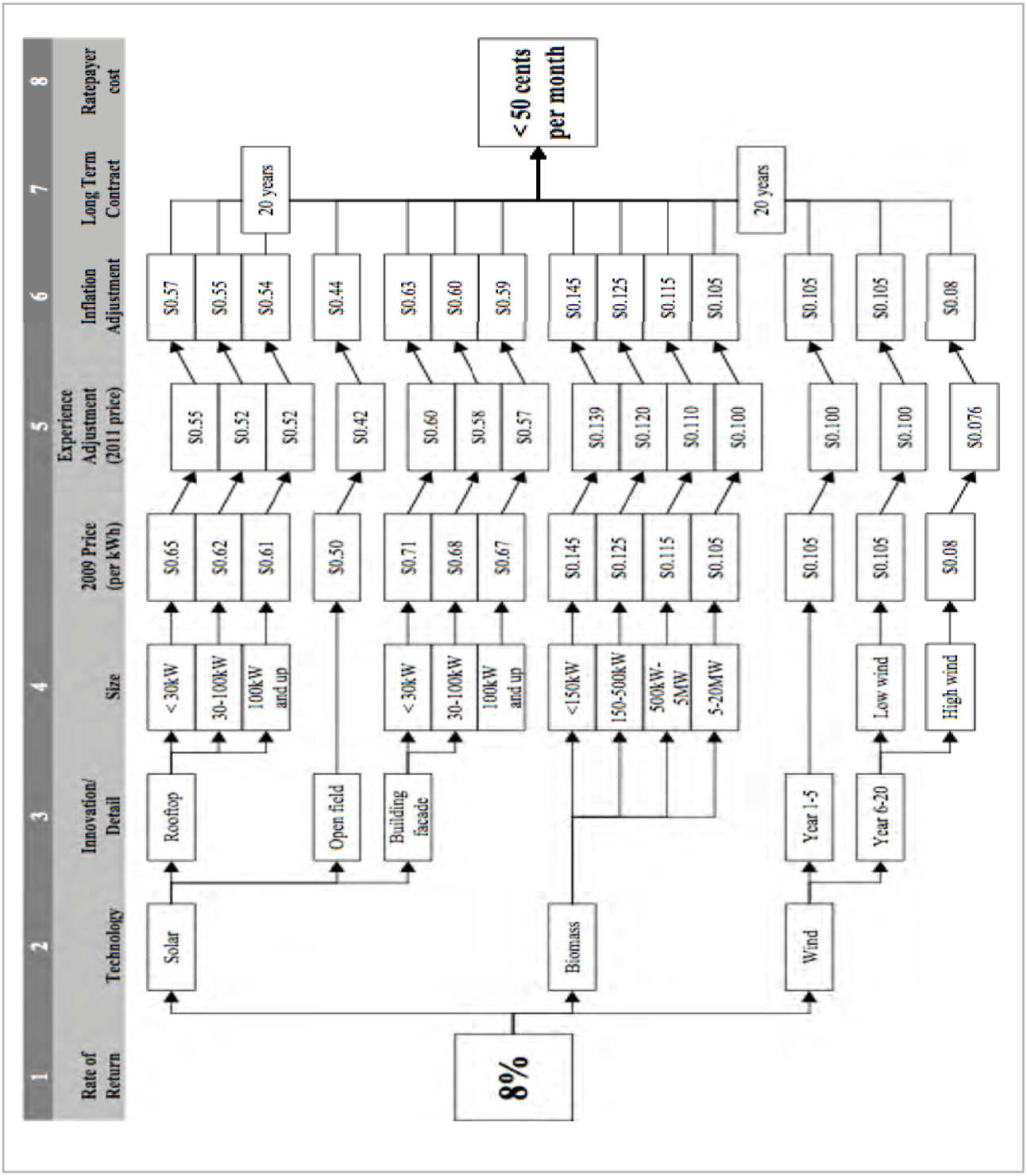
A feed-in tariff promotes simple cost-sharing of the benefits of renewable energy. Any incremental increase in the cost of electricity from projects using the FIT is spread across the entire set of electricity consumers. In European countries, this cost-sharing is national, with partial exemptions for electricity-intensive industries. In the U.S. it may be on a state or on a utility basis.

Example for Setting FIT Rates:

Figure 8 – Size Scaling of Germany's Biomass Tariff

Figure 8 illustrates how Germany scales its biomass tariff to encourage projects at small and large scale.

Figure 9 – A Nuanced Price System Helps Create a Vibrant Renewable Energy Market at Low Cost



Appendix M

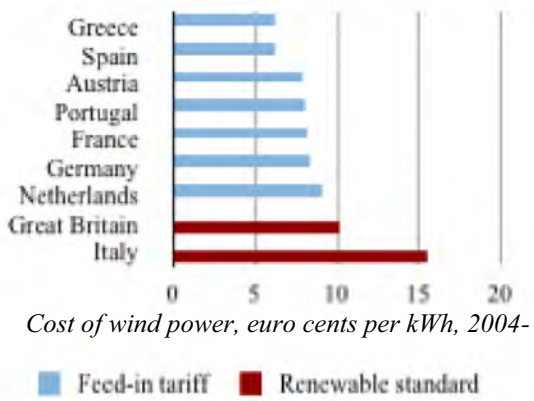
The Economics of a Feed-in Tariff

The motivation for simple renewable energy policy like a FIT is the potential to secure more of the economic and social benefits of a transition to renewable energy than using a patchwork policy approach. Evidence from European countries with feed-in tariffs suggests that this is exactly what happens. This section outlines several ways that feed-in tariffs have improved economic development in the countries that use them.

Cheaper Renewable Power

Studies of the European electricity markets find that electricity from wind turbines is less expensive in countries with feed-in tariffs than those with quantity-based renewable energy policies like renewable portfolio standards (**Figure 10**).[45] Great Britain, for example, requires wind producers to obtain much of their economic value from selling renewable energy credits (RECs) – a certificate of renewable energy produced that utilities must buy – and the uncertainty of REC prices increases financing costs and, ultimately, the cost of wind power for ratepayers.

Figure 10 – Wind Power is Cheaper with a Feed-in Tariff



Cheaper Electricity

If renewable electricity is prioritized – e.g. utilities must buy and feed-in that power to the grid first – then renewable energy displaces other generators. This "merit order" reduces the use of expensive peaking plants and can drive down the overall cost of electricity supply (**Figure 11**).[46] This has been the case in Germany.

Figure 11(a) – Merit Order: Total Cost of Electricity before Renewables

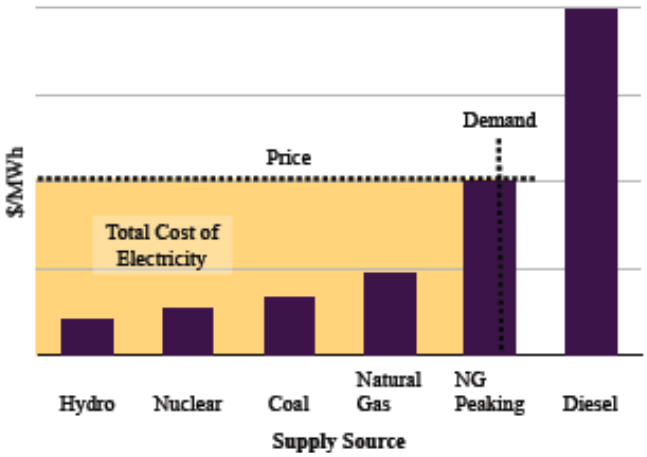


Figure 11(a) illustrates the total price of electricity without renewables. The vertical dotted line represents the peak demand and the horizontal line is the price paid for that peak electricity.

Peak demand requires the use of natural gas peaking plants, which have a high price. This increases the total cost of electricity to consumers, represented by the shaded area.

Figure 11(b) – Merit Order: Renewables Lower Electricity Cost

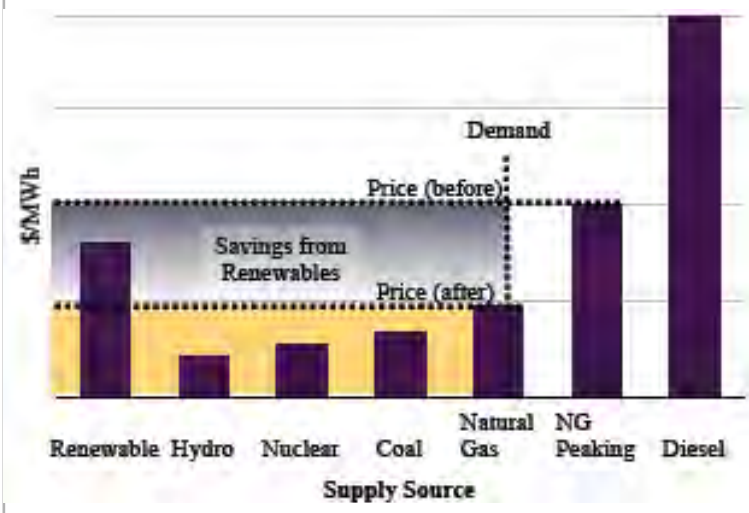


Figure 11(b) illustrates the total price of electricity *with* renewables.

The vertical dotted line (Demand) shows that prioritizing renewable generators reduces the use of natural gas peaking plants. The lower horizontal dotted line (Price - after) shows how this lowers the total cost of electricity. The gradient area shows how the lower wholesale price generates savings that offset and sometimes may eliminate the additional cost to the utility of buying renewables at a premium price (represented by the bar for renewables).

In Germany, the merit order savings from renewables exceeds the premium price paid under the feed-in tariff. In Denmark and Spain, the savings recoup over 80 percent of the higher feed-in tariff costs.

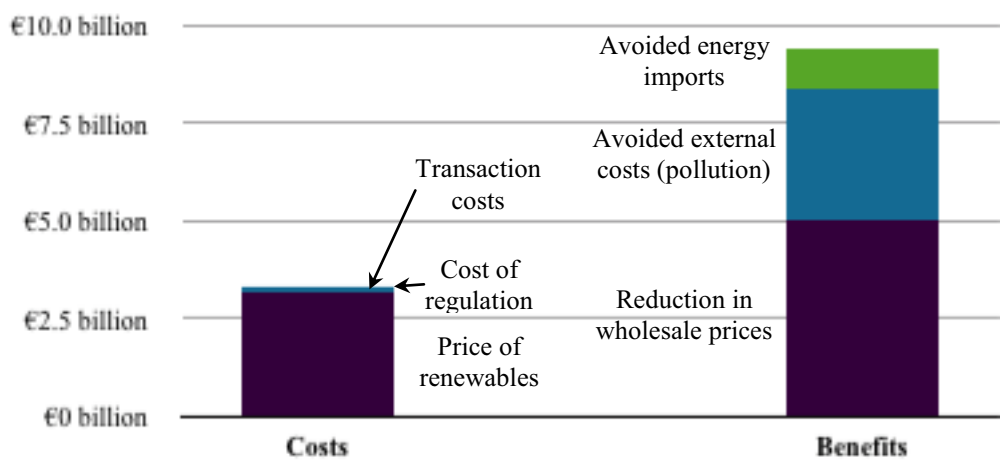
Substantial Job Growth

Both Germany and Denmark were early adopters of feed-in tariffs, and the investment in renewable power has paid back several-fold to their economies. =In Germany, almost 280,000 jobs have been created in the renewable energy industry. In Denmark, there are over 21,000 jobs in the wind industry.

Total Benefits Far Outweigh the Costs

Overall, the benefits of a feed in tariff can outweigh the costs of the premium paid to renewables even without taking into account the economic development impacts. The German ministry overseeing their feed-in tariff estimates that the total benefits of the legislation have exceeded the costs by a factor of three (**Figure 12**).[47]

Figure 12 – Benefits of German Feed-in Tariff far outweigh costs



Local Ownership

A feed-in tariff levels the playing field for local ownership because the all-in-one price drastically simplifies the development process for community-based or individually-owned projects. Rather than having to cobble together an unwieldy structure of local investors and tax equity investors as is the case in the United States, in European countries with feed-in tariffs the profits come from utility revenues, thus avoiding the need to find investors with tax liability. This is important since the economic benefits from encouraging this type of ownership are substantial.

Take a particular wind project, for example, with ten 2 MW turbines located on a farmer's land. **Figure 13** shows that the cash flow for owning the turbines is significantly higher than if the farmer simply leases their land and wind rights to an absentee developer.[48]

This drastic difference also accounts for the much higher economic benefits to a region when wind projects are locally owned rather than absentee owned. **Figures 14 and 15** show both the economic impact and employment impact advantages of local ownership.[49]

Figure 13 – Total Landowner Payments for a 20 MW Wind Project Based on Ownership of Project

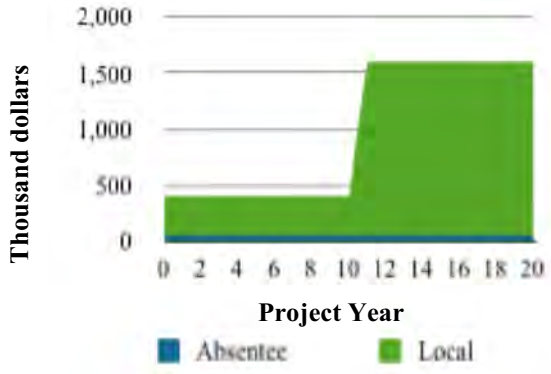


Figure 14 – Local Ownership Means Significantly Higher Economic Impact

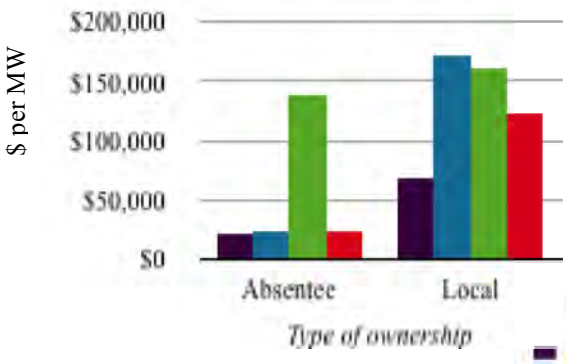
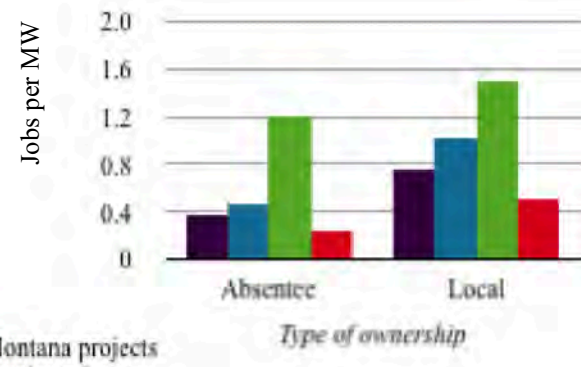
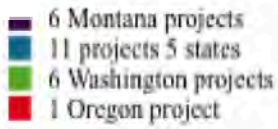


Figure 15 – Local Ownership Means Significantly more Jobs





Minnesota: A Case Study

Minnesota first considered a feed-in tariff in 2008 and the bill introduced in the 2009 session reflects an effort to adapt successful European policies to Minnesota's unique needs. Minnesota already has a nascent wind industry, with over 1,200 MW of wind projects in the ground and many hundreds more planned.

Additionally, the state has shown a strong commitment to encouraging locally owned, community-based renewable energy projects. Like Germany and Denmark, the state has a significantly higher rate of local ownership than other regions of the U.S (approximately 20 percent of wind projects). And yet, development of community-based projects has lagged as incentives continue to favor absentee ownership and larger scale projects and discriminate against locally owned and smaller projects.

Thus, the feed-in tariff proposal for Minnesota has a few key features:

- Local ownership – only locally owned projects can use the feed-in tariff incentive (as defined by the Community-Based Energy Development law)[50].
- Smaller wind projects –the revised FIT bill will only support wind projects under 20 MW in size.
- Program cap: the Minnesota legislation includes a capacity cap, set at 20 percent of the 25 percent Renewable Energy Standard by 2025 (approximately 5 percent of retail sales).

Costs and Benefits of a Minnesota Feed-in Tariff

What might be the costs and benefits of a Minnesota FIT as currently designed?

For illustration purposes, the following analysis assumes that the feed-in tariff in Minnesota would be enacted in 2010 and that up to 20 percent of the state's renewable energy goal could be covered by projects in the FIT program. This would be close to 5 percent of each utility's load. It is assumed that wind will be 95 percent of projects and solar 5 percent, equivalent to 1042 MW of wind power and 151 MW of solar PV by 2025.

Costs to Ratepayers and Taxpayers

The cost to Minnesota ratepayers of the amount of renewable energy generated in this example is very small, approximately 41 cents per household per month at its peak. Because the prices step down over time, however, the feed-in tariff will eventually lower electricity bills by more than this, saving households around 8 cents per month in 2025.

The ratepayer cost of Minnesota's feed-in tariff is small, peaking at 41 cents per household per month.

The primary reason for lower costs is stability. Unlike expiring state and federal incentives or tax credits, a tariff is a long-term, fixed price for electricity that is available to everyone regardless of tax liability. This is particularly important to small producers, who can't depend on multiple, diverse projects to support them if an income stream dries up. Such stability is not only less expensive, it's more effective at reaching renewable electricity generation goals.[51] Mandate systems have volatile prices because the producers may rely on the sale of their renewable certificates to supplement the power purchase price. Because selling these credits on the market is more unpredictable than a long-term, fixed-price contract, feed-in tariffs create more investor confidence and lower the cost of capital.[52]

> "I live out on the Buffalo Ridge...I look out my window and I see hundreds of wind turbines. When I look at those turbines I'm happy and I'm sad... Most of those turbines are owned by our friends, the foreign multinationals. Out of two counties in Minnesota we export about 80 million dollars a year to france, florida, italy, portugal, spain.
>
> All of our energy future is going out the door when we could be turning that into something real for us."
>
> *–Dan Juhl, community wind developer, Minnesota*

Benefits to the State

The renewable energy projects supported by a feed-in tariff will provide a premium in economic development, in jobs and financial impact on the local economy because of their broad ownership structure.

Several studies have documented the significantly higher impact of local ownership of renewable energy projects on employment and economic benefits. The research typically shows nearly two-thirds again as many jobs in a locally owned project compared to an absentee owned one, and anywhere from two to five times the economic impact.[53] **Figure 16** illustrates the potential impact of a feed-in tariff on Minnesota's economy, given the research findings.

Figure 16(a) – 1042 MW of Minnesota Wind Produces More Jobs if Locally Owned

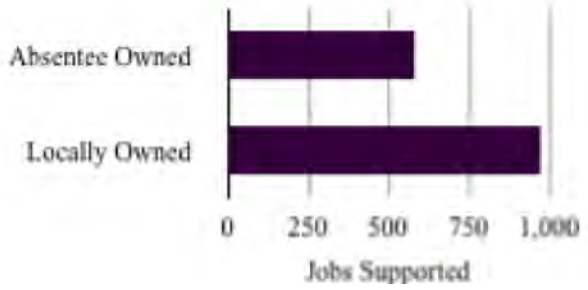
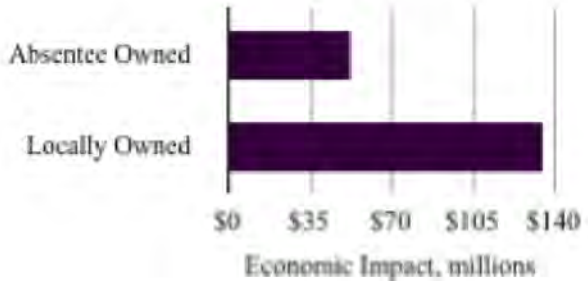


Figure 16(b) – 1042 MW of Minnesota Wind Produces More Economic Impact if Locally Owned



Questions about Feed-In Tariffs

With a history of favoring market interventions based on quantity rather than price, many U.S. utility and regulatory representatives raise concerns about feed-in tariffs. Here are some answers to common questions or criticisms.

Won't a Feed-In Tariff be Expensive?

No. In fact, studies suggest that a feed-in tariff may be a less expensive route than other policies to expanding renewable energy production, while generating greater domestic or local economic benefits.

Because it sets all-in-one prices, a feed-in tariff tariff often looks a lot bigger than the prices utilities are used to paying or governments are used to providing. The difference is an accounting one. Wind and solar producers will get a price under a FIT as they do in the current market with its byzantine array of incentives, rebates, and tax advantages. But a guaranteed, long term contract reduces the risk premium for financing renewable energy projects, often reducing the cost of capital and, thus, the cost of getting more renewable energy.

The cost difference is highlighted in **Figure 17,** which shows that European countries with feed-in tariffs have substantially lower acquisition costs for wind power than those with quantity-based policies.

Studies have also found that the additional cost of feed-in tariffs is offset, sometimes almost completely, by reducing the wholesale cost of electricity. In most countries with feed-in tariffs, renewable energy is the highest priority electricity source, so it supplants other generators such as nuclear, coal and natural gas. This "merit order" actually reduces the overall cost of electricity (**Figure 18**).

Figure 17 – Wind Power is Cheaper with a Feed-in Tariff

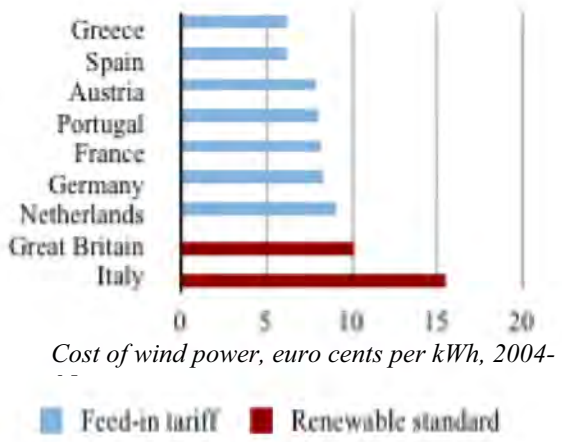


Figure 18(a) – Merit Order: Total Cost of Electricity before Renewables

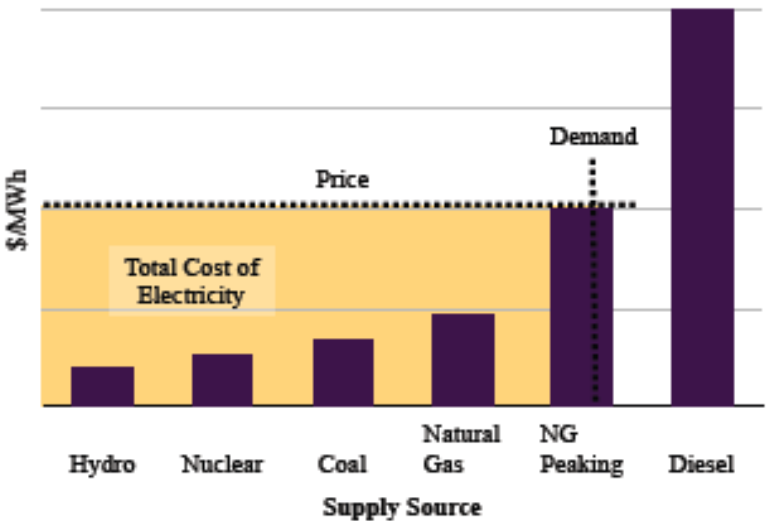


Figure 11(a) illustrates the total price of electricity without renewables. The vertical dotted line represents the peak demand and the horizontal line is the price paid for that peak electricity.

Peak demand requires the use of natural gas peaking plants, which have a high price. This increases the total cost of electricity to consumers, represented by the shaded area.

Figure 18(b) – Merit Order: Renewables Lower Electricity Cost

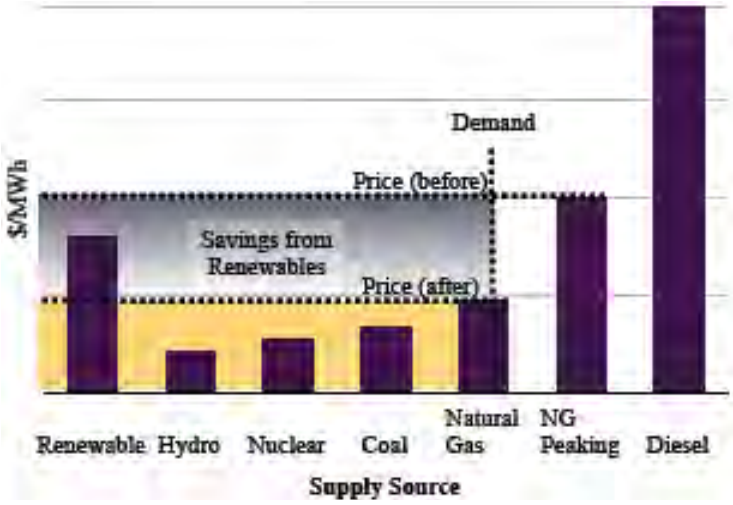


Figure 11(b) illustrates the total price of electricity *with* renewables.

The vertical dotted line (Demand) shows that prioritizing renewable generators reduces the use of natural gas peaking plants. The lower horizontal dotted line (Price - after) shows how this lowers the total cost of electricity. The gradient area shows how the lower wholesale price generates savings that offset and sometimes my eliminate the additional cost to the utility of buying renewables at a premium price (represented by the bar for renewables).

If we have an RPS, do we need a Feed-in Tariff?

Yes. An RPS provides a timeline to the utilities, but does not push projects forward. A FIT sends a signal to investors; it makes projects happen. Moreover, a FIT can be designed to not only accelerate renewable energy but to do so in a way that achieves economic development or other important social goals, such as allowing more energy consumers to become energy producers.

By supporting local ownership and dispersed generation, a feed-in tariff can increase the economic benefits and reduce the cost of acquiring more renewable energy. Both policies can increase the level of renewable electricity generation, but the feed-in tariff is a more comprehensive strategy.

Isn't an RPS more market-oriented?

No. An RPS sets a quantity (and is often supplemented and driven by tax incentives, rebates, and other price interventions). A feed-in tariff focuses on price. Neither is a fully market-based policy. Nor is the abundant use of tax incentives and rebates a market-based policy.

The advantage of a feed-in tariff is that it shifts competition in the market. Instead of a free-for-all where wind fights solar fights biomass and large fights small for the lowest bid, the competition is among developers and manufacturers to reduce prices to maximize their welfare. And the data shows that this kind of market competition achieves less expensive renewable energy (**Figure 17**, previous page).

Conclusion

The United States would benefit from a change in renewable energy policy to a feed-in tariff. The lesson from Europe is clear: Americans can continue to debate "market-based" ideas and tax credits or they can jump to the solutions that work.

> "We decided we will reduce CO_2 until 2020, 40 percent, [and by] 2050 with 80 percent. And then we debated the instruments.
>
> I hear arguments [at this Conference] we discussed in Germany 10 or 15 years ago. It's the same debate....In Germany, we had a decision, we made a law...the Renewable Energy Resources Act. And it worked. You can see the results."
>
> *–Willi Voigt, former minister in the German state of Schleswig-Holstein*

In addition to turbocharging renewable energy development, a feed-in tariff unlocks the potential of dispersed generation and community ownership. Compared to the byzantine array of incentives and rules facing renewable energy producers, a feed-in tariff decreases the economic and legal costs of doing business and increases the social and economic benefits.

About the Author

John Farrell is a research associate on the New Rules Project at the Institute for Local Self-Reliance, where he examines the benefits of local ownership and dispersed generation of renewable energy. His latest paper is Rural Power: Community-Scaled Renewable Energy and Rural Economic Development. You can find more of his work and more information on the New Rules Project at www.newrules.org. He can be reached at: jfarrell@ilsr.org or 612-379-3815 x210.

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Wind-Works.org

by Paul Gipe

Britain to Launch Innovative Feed-in Tariff Program in 2010

Proposes World's Highest Tariffs for Small Wind Turbines

July 23, 2009

By Paul Gipe

They said it couldn't be done, but Britain has risen to the challenge. Britain's Secretary of State for Energy and Climate Change Ed Miliband has released long-awaited details on the Labour Government's feed-in tariff policy.

Miliband, an up-and-coming politician in the cabinet of besieged Prime Minister Gordon Brown, has done what was once unthinkable, put a British stamp of approval on feed-in tariffs as a policy mechanism for developing renewable energy.

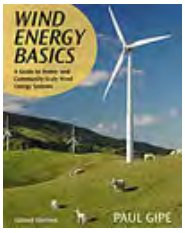
The move has potentially far reaching ramifications in the English speaking world where there has been reluctance to use full-fledged systems of feed-in tariffs, sometimes on ideological grounds. Now that Britain, Ontario, and South Africa, two of Britain's former colonies, have definitively moved toward implementing sophisticated feed-in tariff programs, there may be less reticence to do so elsewhere in the Anglophone world.

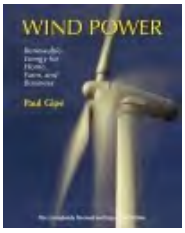
Of course, like politicians everywhere, Miliband had to rebrand feed-in tariffs to something more to his liking. His "clean energy cash back" creates yet another term for what everyone else calls, sometimes grudgingly, feed-in tariffs.

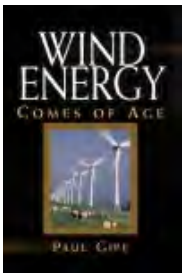
Nevertheless, the program's designers took their task seriously and didn't opt for a system of faux or false feed-in tariffs, what North American campaigners have begun derisively calling FITINOs, feed-in tariffs in name only.

The British proposal has also contributed several innovative new twists on feed-in tariff design that will mark the program as "made in the United Kingdom".

One new feature is the inclusion of tariffs for Combined Heat &

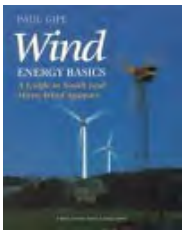






Appendix N

Power (CHP). While not a first, it is one of the few programs to do so. Another feature of the proposed program is a distinct tariff for small solar PV systems on new homes, and a separate tariff for existing homes.



Most significantly, program designers have included a mechanism to encourage homeowners and small businesses to reduce their electricity consumption. For example, a solar PV generator will be paid for all their generation. However, they will receive a bonus, currently at £0.05/kWh ($0.08 USD/kWh, $0.09 CAD/kWh), for electricity delivered to the grid over and above their domestic consumption. Thus, if a homeowner is able to cut their domestic consumption, and sell more electricity to the grid as a result, they are paid the bonus on top of the posted feed-in tariff.

The proposed program, like the successful programs it was modeled after, was designed to "set tariffs at a level to encourage investment in small scale low carbon generation." This is in contrast to faux feed-in tariffs that set the tariffs on the "value" of renewable energy to the system as in the California Public Utility Commission's largely ineffective program.

British designers were instructed to calculate tariffs not on ideology or economic theory but on the tariffs needed so "that a reasonable return can be expected for appropriately sited technologies" to meet the country's renewable energy and carbon mitigation targets.

Unfortunately, the program's targets are timid at best, two percent of Britain's electricity consumption by 2020, and the tariffs are limited by law to projects less than 5 MW to protect the country's stumbling Renewable Obligation, the preferred mechanism for developing larger projects.

The two percent target requires the generation of only 8 billion kWh (TWh) per year. For comparison, Germany generated 40 TWh in 2008 from wind energy and more than 4 TWh from solar PV. France, Britain's longtime cross-channel rival, generated nearly 6 TWh from wind energy in 2008 from its system of feed-in tariffs.

Some of the proposed tariffs are not competitive with those on the continent, or those in Ontario. "For community-scale or larger on-site projects," says David Timms, a senior campaigner with Friends of the Earth (UK), "the rates [tariffs] are inadequate."

The tariff proposed for large wind turbines is low by international standards. Britain has some of the best winds in Europe. Nevertheless, many of the smaller projects that may be built under the feed-in tariff program may not be as advantageously sited as commercial projects under the Renewable Obligation. Consequently, the proposed tariff for wind projects from 500 kW to 5 MW may be insufficient to drive development.

Timms also adds that the "degression for solar PV is quite aggressive" at 7 percent per year and that the bonus payment of £0.05/kWh for export to the grid may not be bankable. Because the bonus payment will fluctuate with the "market price" it won't

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necessarily have a fixed value and, consequently, it will be discounted by banks providing debt for projects financed under the feed-in tariff.

If implemented as proposed, though, the British program will offer some of the highest tariffs for small wind energy in the world. The tariffs will rival those in Italy, Israel, Switzerland, and Vermont, possibly reflecting the British government's belief that it can encourage development of a domestic small wind turbine industry. For example, the tariff proposed for small wind turbines from 1.5 kW to 15 kW is £0.23/kWh ($0.38 USD/kWh, $0.42 CAD/kWh) about that paid in Italy and Israel.

The proposed program also includes a number of anti-gaming provisions to avoid breaking up bigger projects into several small ones to fit within the 5 MW project size cap. These will prevent companies from moving big wind projects from the Renewable Obligation to the feed-in tariff program.

Britain's feed-in tariff program is expected to begin in early April, 2010 after an extensive consultation. Below is a summary of the program's key elements.

- Program Cap: 2% of Supply, 8 TWh in 2020
- Project Cap: 5 MW
- Generator can be green field (doesn't have to be a metered customer)
- Contract Term: 20 years, solar PV 25 years
- Program Review: 2013
- Costs for the program will be borne by all British ratepayers proportionally

While limited in scope, Britain's proposed feed-in tariff program is as sophisticated, if not more so, as any proposed in the United States, and will put the country on the world map of innovative renewable energy policy.

Consultation on Renewable Electricity Financial Incentives 2009: Program Details

Consultation on Renewable Electricity Financial Incentives: Background Documents & Reports

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Renewable Tariffs in Great Britain (Proposed)						
07/23/09						
		Tariff				
			1.1564	1.57323	1.41779	
	Years	£/kWh	€/kWh	CAD/kWh	USD/kWh	Degression
Wind Energy	20					
<1.5 kW		0.305	0.353	0.555	0.500	0
>1.5 kW<15 kW		0.230	0.266	0.418	0.377	0
>15 kW<50 kW		0.205	0.237	0.373	0.336	0
>50 kW<250 kW		0.180	0.208	0.327	0.295	0
>250 kW<500 kW		0.160	0.185	0.291	0.262	0
>500 kW<5 MW		0.045	0.052	0.082	0.074	0
Solar PV	25					
<4 kW		0.310	0.358	0.564	0.508	-7%
<4 kW Retrofit		0.365	0.422	0.664	0.598	-7%
>4 kW<10 kW		0.310	0.358	0.564	0.508	-7%
>10 kW<100 kW		0.280	0.324	0.509	0.459	-7%
>100 kW<5 MW		0.260	0.301	0.473	0.426	-7%
Stand Alone System		0.260	0.301	0.473	0.426	-7%
Hydro	20					
<10 kW		0.170	0.197	0.309	0.279	0
>10 kW<100 kW		0.120	0.139	0.218	0.197	0
>100 kW<1 MW		0.085	0.098	0.155	0.139	0
>1 MW<5 MW		0.045	0.052	0.082	0.074	0
Anaerobic Digestion	20					
Electricity Only		0.090	0.104	0.164	0.148	0
CHP		0.115	0.133	0.209	0.189	0
Biomass	20					
<50 kW		0.090	0.104	0.164	0.148	0
<50 kW<5 MW		0.045	0.052	0.082	0.074	0
CHP		0.090	0.104	0.164	0.148	0
Bonus for Export	20	0.050	0.058	0.091	0.082	0
Existing microgenerators transferred from RO.	20	0.090	0.104	0.164	0.148	
Begins April 10, 2010 though systems installed up to that time can qualify.						
Solar PV term is 25 years.						

-End-

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Ontario Unveils North America's First Feed-In Tariff

Price Guarantees for Large and Small Renewable Energy Projects will Create Jobs

March 12, 2009

Ontario is poised to introduce new electricity pricing to encourage the development of renewable energy from a diverse range of producers including homeowners, community-based groups and larger scale commercial generators.

As North America's first guaranteed pricing structure – called a feed-in tariff (FIT) – for various forms of electricity production, it would offer a stable, competitive price combined with a long term contract. A FIT would establish prices for energy generated from renewable sources, including on-shore and off-shore wind, hydroelectric, solar, biogas, biomass and landfill gas. Proposed prices and program guidelines announced today will form the basis of an eight-week consultation process with renewable energy stakeholders and several general information sessions for the interested public.

"The proposed feed-in tariff program would help spark new investment in renewable energy generation and create a new generation of green jobs," said George Smitherman, Deputy Premier and Minister of Energy and Infrastructure. "It would give communities and homeowners the power and tools they need to participate in the energy business in the new green economy."

"Ontario has made great progress in procuring renewables, becoming Canada's leading province for wind power," added Colin Andersen, CEO of the Ontario Power Authority. "This proposed FIT program would build on our success and ensure that more contracts turn into projects sooner."

The proposed Green Energy Act (GEA), if passed, would establish Ontario as North America's leader in renewable energy, drive green investment in the province and create 50,000 jobs in the first three years. Additional changes proposed under the GEA would also make it easier and faster for projects to get connected to the grid. Other countries – particularly Germany, Spain and Denmark – have successfully used FITs to encourage the development of renewable energy projects.

The proposed FIT prices were developed based on experience here in Ontario and in other jurisdictions. Prices differ based on project size and type of renewable energy technology. They cover capital, operating and maintenance costs and allow for a reasonable rate of return on investment over an approximate 20-year period. They also provide special categories for community-based projects.

Appendix O

Ontario's Energy Supply Mix

SUPPLY TYPE	FUEL TYPE	LOCATION	CURRENT/PROPOSED PRICE (kWh)
Peaking fuel for reliability*	8% natural gas	various plants	8.5¢ - 14¢
Renewable Opportunities**	TBD% – new renewables portfolio	wind solar biomass biogas landfill gas new hydro	8¢ - 44.3¢
	1-2% rooftop solar***		53.9¢ - 80.2¢
Baseload 76%*	53% nuclear	Pickering Darlington Bruce	6¢ - 7¢
	23% hydroelectric	Niagara Falls St. Lawrence River Northern rivers	5.7¢ - 6.2¢

* Existing supply
** Emerging supply
*** 1% = approximately 100,000 residential rooftops

Solar micro-generation, 10 kilowatts and under, will enjoy the highest tariff in order to incent Ontarians to participate. If the proposed FIT program leads to 100,000 residential solar rooftop installations, it will amount to one percent of Ontario's supply mix.

The OPA will begin consulting with renewable energy stakeholders on the proposed design of a FIT program, including eligibility criteria and proposed pricing next week. Weekly sessions run from March 17 to May 5, 2009.

Quick Facts

- In 2008, 25% of Ontario's electricity generation came from renewable energy sources.
- Nearly 1,200 megawatts of wind capacity will be online by end of 2009, enough to power almost 325,000 homes.
- Investments in new renewable energy projects already in place or under construction in Ontario total about $4 billion.
- Rooftop solar prices should drive installations in urban centres, matching areas with high summer air conditioning demand.
- Methane capture at landfill sites will provide significant greenhouse gas emission reductions.
- Many waterpower projects and partnerships with First Nations and Métis involvement are anticipated, especially in the North.
- In some cases, like farm-based biogas and hydroelectric production, an on-peak producing incentive will be offered.

Appendix O

Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario

Technology	Proposed size tranches	Proposed ¢/kWh
Biomass*		
	Any size	12.2
Biogas*		
	≤ 5 MW	14.7
	> 5 MW	10.4
Waterpower*		
	≤ 50 MW	12.9
Community Based	≤ 2 MW	13.4
Landfill gas*		
	≤ 5MW	11.1
	> 5 MW	10.3
Solar PV		
Rooftop	≤ 10 kW	80.2
	10 – 100 kW	71.3
	100 – 500 kW	63.5
	> 500 kW	53.9
Ground Mounted	≤ 10 MW	44.3
Wind		
Onshore	Any size	13.5
Offshore	Any size	19.0

Appendix O

Community Based	≤ 10 MW	14.4

*on/off peak pricing applies (see Backgrounder for details)

Print

Appendix O

Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario Base Date: July 8, 2009			
Renewable Fuel	**Proposed size tranches**	**Proposed Contract Price ¢/kWh**	**Escalation Percentage****
Biomass*^			
	≤ 10 MW	13.8	20%
	> 10 MW	13.0	20%
Biogas*^			
On-Farm	≤ 100 kW	19.5	20%
On-Farm	> 100 kW ≤ 250 kW	18.5	20%
	≤ 500 kW	16.0	20%
	>500 kW ≤ 10 MW	14.7	20%
	> 10 MW	10.4	20%
Waterpower*^			
	≤ 10 MW	13.1	20%
	> 10 MW	12.2	20%
Landfill gas*^			
	≤ 10MW	11.1	20%
	> 10 MW	10.3	20%
Solar PV			
Any type	≤10 kW	80.2	0%
Rooftop	> 10 ≤ 250 kW	71.3	0%
Rooftop	> 250 ≤ 500 kW	63.5	0%
Rooftop	> 500 kW	53.9	0%
Ground Mounted^	≤ 10 MW	44.3	0%
Wind^			
Onshore	Any size	13.5	20%
Offshore	Any size	19.0	20%

*Peak Performance Factor applies.

^Aboriginal Price Adder and Community Price Adder eligible as outlined in Appendix A below.

**Escalation Percentage will be applied to eligible Renewable Fuels as calculated in Exhibit B of draft FIT Contract.

Draft

Appendix A: Maximum Aboriginal Price Adder and Maximum Community Price Adder*:

Renewable Fuel	Wind	PV (Ground Mounted)	Water	Biogas	Biomass	Landfill Gas
Maximum Aboriginal Price Adder (¢/kWh)	1.5	1.5	0.9	0.6	0.6	0.6
Maximum Community Price Adder (¢/kWh)	1.0	1.0	0.6	0.4	0.4	0.4

* The percentage of the Maximum Aboriginal Price Adder or Maximum Community Price Adder added to the Contract Price is based on the Aboriginal or Community Participation Level as defined in the FIT Rules.

News

General Motors Corporation

GM Communications
Detroit, Mich., USA
media.gm.com

For Release: 8:00 AM EDT
August 11, 2009

Chevrolet Volt Expects 230 mpg in City Driving

First mass-produced vehicle to claim more than 100 mpg composite fuel economy

Tentative EPA methodology results show 25 kilowatt hours/100 miles electrical efficiency in city cycle

- Plugging in daily is key to high-mileage performance

WARREN, Mich. – The Chevrolet Volt extended-range electric vehicle is expected to achieve city fuel economy of at least 230 miles per gallon, based on development testing using a draft EPA federal fuel economy methodology for labeling for plug-in electric vehicles.

The Volt, which is scheduled to start production in late 2010 as a 2011 model, is expected to travel up to 40 miles on electricity from a single battery charge and be able to extend its overall range to more than 300 miles with its flex fuel-powered engine-generator.

"From the data we've seen, many Chevy Volt drivers may be able to be in pure electric mode on a daily basis without having to use any gas," said GM Chief Executive Officer Fritz Henderson. "EPA labels are a yardstick for customers to compare the fuel efficiency of vehicles. So, a vehicle like the Volt that achieves a composite triple-digit fuel economy is a game-changer."

According to U.S. Department of Transportation data, nearly eight of 10 Americans commute fewer than 40 miles a day **http://tinyurl.com/U-S-DOTStudy**.

"The key to high-mileage performance is for a Volt driver to plug into the electric grid at least once each day," Henderson said.

Volt drivers' actual gas-free mileage will vary depending on how far they travel and other factors, such as how much cargo or how many passengers they carry and how much the air conditioner or other accessories are used. Based on the results of unofficial development testing of pre-production prototypes, the Volt has achieved 40 miles of electric-only, petroleum-free driving in both EPA city and highway test cycles.

Under the new methodology being developed, EPA weights plug-in electric vehicles as traveling more city miles than highway miles on only electricity. The EPA methodology uses kilowatt hours per 100 miles traveled to define the electrical efficiency of plug-ins. Applying EPA's methodology, GM expects the Volt to consume as little as 25 kilowatt hours per 100 miles in city driving. At the U.S. average cost of electricity (approximately 11 cents per kWh), a typical Volt driver would pay about $2.75 for electricity to travel 100 miles, or less than 3 cents per mile.

The Chevrolet Volt uses grid electricity as its primary source of energy to propel the car. There are two modes of operation: Electric and Extended-Range. In electric mode, the Volt will not use gasoline or produce tailpipe emissions when driving. During this primary mode of operation, the Volt is powered by electrical energy stored in its 16 kWh lithium-ion battery pack.

When the battery reaches a minimum state of charge, the Volt automatically switches to Extended-Range mode. In this secondary mode of operation, an engine-generator produces electricity to power the vehicle. The energy stored in the battery supplements the engine-generator when additional power is needed during heavy accelerations or on steep inclines.

“The 230 city mpg number is a great indication of the capabilities of the Volt’s electric propulsion system and its ability to displace gasoline,” said Frank Weber, global vehicle line executive for the Volt. “Actual testing with production vehicles will occur next year closer to vehicle launch. However, we are very encouraged by this development, and we also think that it is important to continue to share our findings in real time, as we have with other aspects of the Volt’s development.”

About Chevrolet

Chevrolet is one of America's best-known and best-selling automotive brands, and one of the fastest growing brands in the world. With fuel solutions that go from "gas-friendly to gas-free," Chevy has nine models that get 30 miles per gallon or more on the highway, and offers three hybrid models. More than 2.5 million Chevrolets that run on E85 biofuel have been sold. Chevy delivers expressive design, spirited performance and provides the best value in every segment in which it competes. More information on Chevrolet can be found at www.chevrolet.com. For more information on the Volt, visit media.gm.com/volt.

General Motors Company, one of the world's largest automakers, traces its roots back to 1908. With its global headquarters in Detroit, GM employs 235,000 people in every major region of the world and does business in some 140 countries. GM and its strategic partners produce cars and trucks in 34 countries, and sell and service these vehicles through the following brands: Buick, Cadillac, Chevrolet, GMC, GM Daewoo, Holden, Opel, Vauxhall and Wuling. More information on the new General Motors Company can be found at www.gm.com.

# # #

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Appendix Q

EXPLORING VANCOUVER ISLAND'S ENERGY FUTURE

A Workshop with BC Hydro & Rocky Mountain Institute

July 14, 2003

Final Report

September 29, 2003

Prepared by:
Rocky Mountain Institute

Project Manager:
Joel N. Swisher, PhD, PE

Appendix R

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EXPLORING VANCOUVER ISLAND'S ENERGY FUTURE

A Workshop with BC Hydro & Rocky Mountain Institute
July 14, 2003

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

Appendix R

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)

[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.

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- 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%

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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

[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

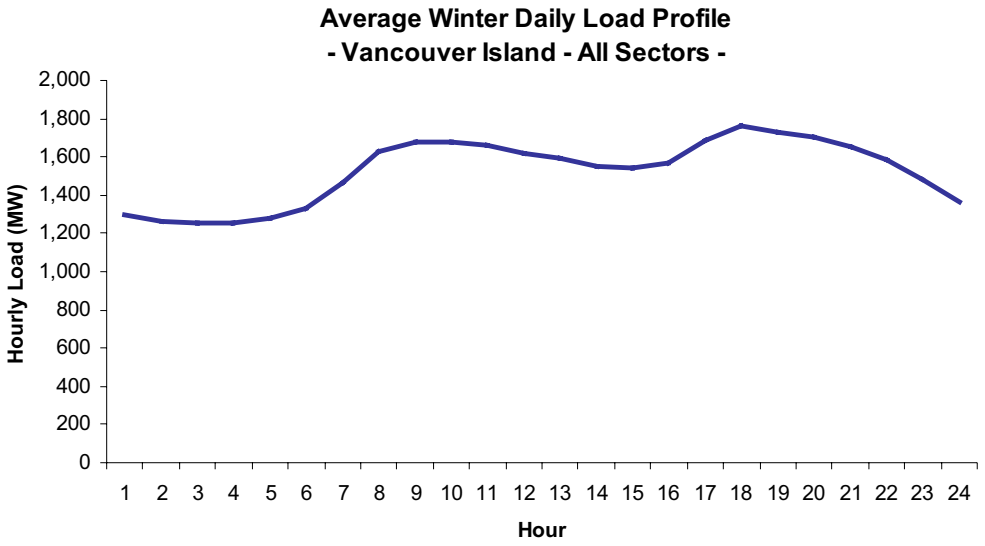
Peak Load Management

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

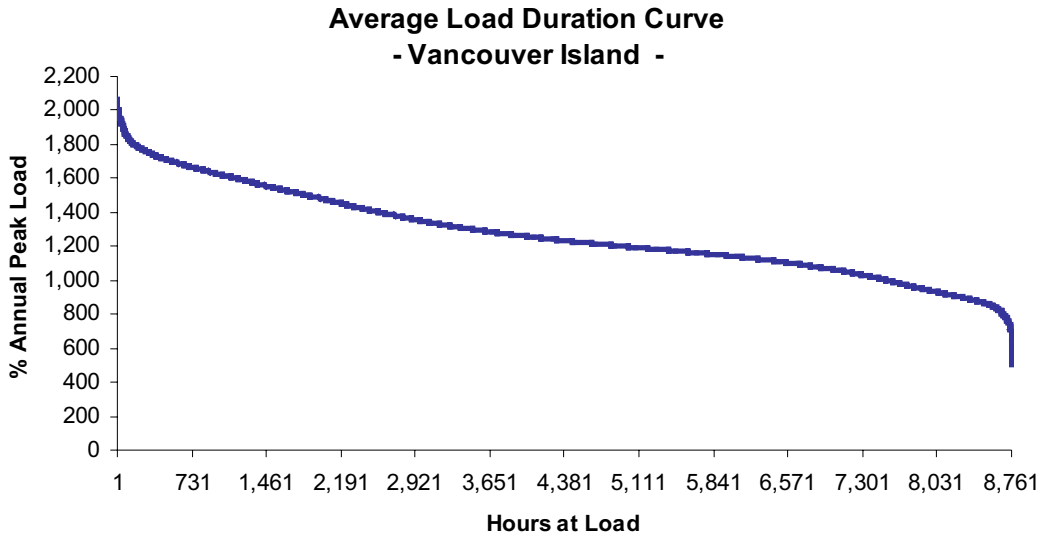
system. However, because of capacity constraints on VI, its system is limited by its capacity to meet peak demand, rather than strictly energy. In the future, the BC Hydro system as a whole will also become more capacity-limited. In a capacity-limited system such as on VI, savings in peak demand (MW) 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

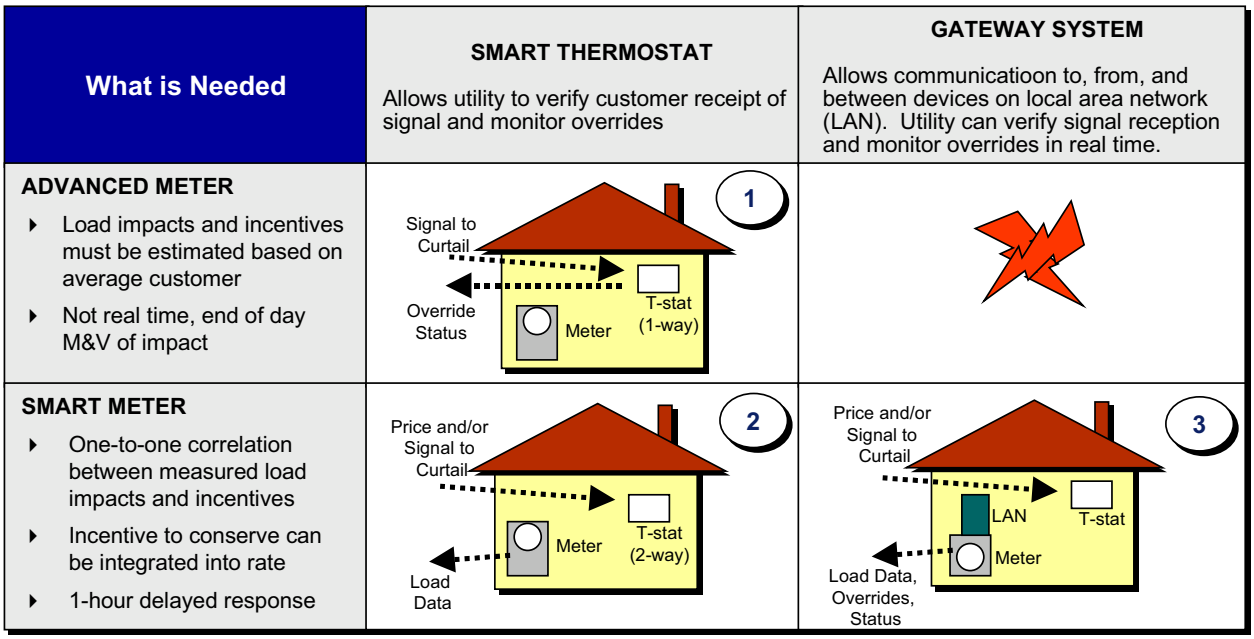
Residential load management has been used effectively to control air conditioning, heating, and hot water loads by several US and Canadian utilities. The prior generation of residential load control was primarily based on under-frequency relays to cut off power to the end use device.

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.



Lessons Learned in Industrial Load Management

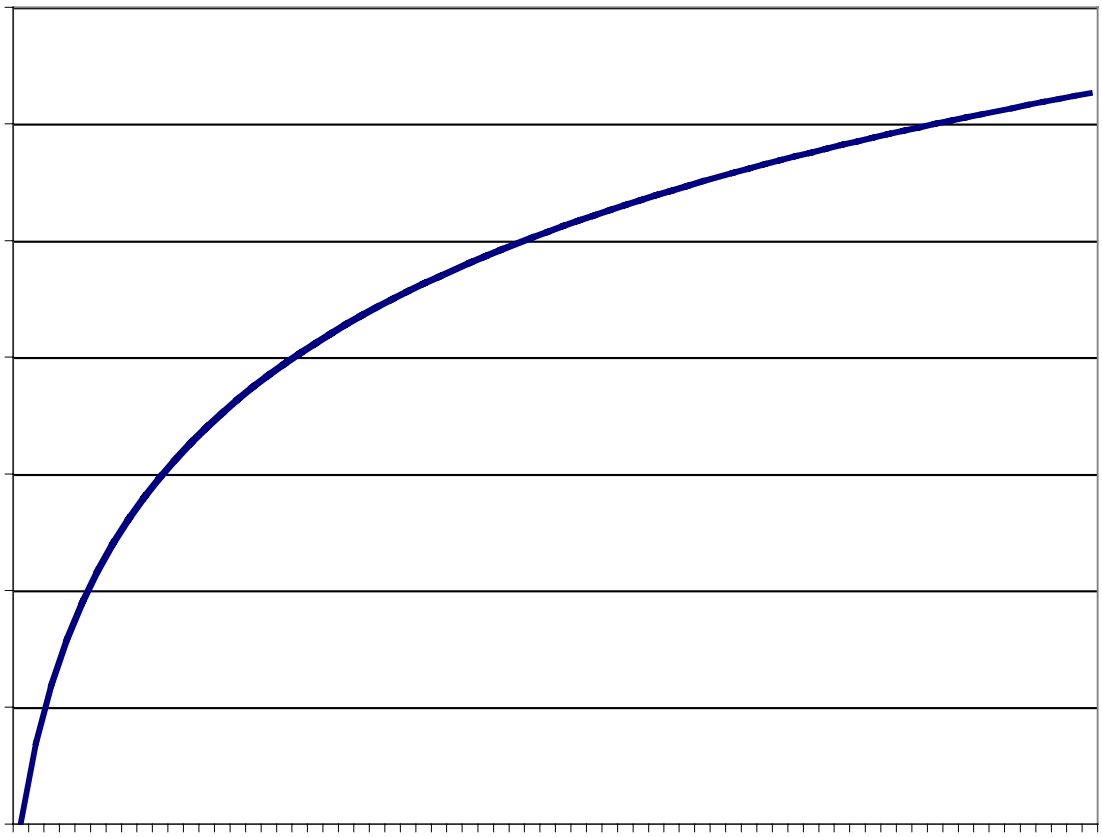
The recent power crises in the United States have provided important intelligence about how industrial consumers respond to load management initiatives. First, industrial consumers have greater price elasticity and manufacturing flexibility than most utilities recognized. What has been lacking was the 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

[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.

Appendix R

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.

Appendix R