BC hydro

Integrated Resource Plan

Appendix 7K

Technical Advisory Committee – Written Submissions on Consultation Topics 2013

INTEGRATED RESOURCE PLAN

TECHNICAL ADVISORY COMMITTEE
Written Submissions October 2013

About the IRP Technical Advisory Committee

An IRP Technical Advisory Committee (TAC) was established by BC Hydro in December 2010 to provide detailed technical input and feedback to assist BC Hydro in creating a thorough and well-considered Integrated Resource Plan (IRP). This advisory input is in addition to input provided by First Nations, stakeholders, and members of the public and through the province-wide, IRP consultation process.

The Committee membership consists of knowledgeable participants with a significant stake, interest and experience in BC Hydro's resource planning process. A Terms of Reference document details the purpose, mandate, roles and responsibilities and process management of the Committee's work. The Committee met periodically throughout the development of the IRP to review the technical inputs to the analysis, the results of the analysis, and ultimately the draft IRP in May 2012 and the August 2013 IRP. The Terms of Reference, meeting agendas, presentations and supporting materials can be found at www.bchydro.com/irp under Document Centre.

Written Submissions on the August 2013 IRP

The August 2013 IRP was submitted to the provincial government on August 2, 2013. In a letter dated August 23, 2013, the Minister of Energy and Mines instructed BC Hydro to provide public notice it had submitted the IRP to Government, to provide public access to the IRP and to conduct a final round of consultation related to the IRP by October 18, before re-submitting the IRP to government by November 15, 2013. From September 3 to October 18, BC Hydro invited written feedback from the public, stakeholders and First Nations.

As stated in the IRP TAC's Terms of Reference, "At key junctures during the process, committee members will be asked to provide attributed comments to BC Hydro on core planning topics of the IRP to form part of the consultation record."

At TAC Meeting #7 held September 23, 2013, TAC members were provided with an opportunity to ask questions and seek clarification on the plan. At that meeting, TAC members were requested to submit individual, written comments on the August 2013 IRP and were advised that feedback would be considered along with feedback collected from First Nations and public and stakeholders, as BC Hydro finalized its plan for submission to government by November 15, 2013.

Submissions received are attached in the following order:

- BC First Nations Energy and Mining Council
- BC Pensioners' and Seniors' Organization
- BC Sustainable Energy Association
- Clean Energy Association of BC
- Commercial Energy Consumers Association of BC
- Fortis BC

- The Pembina Institute
- Association of Major Power Customers of BC
- Attachment to the Association of Major Power Customers of BC's submission

WRITTEN SUBMISSION FROM:

FIRST NATIONS ENERGY AND MINING COUNCIL

TECHNICAL ADVISORY COMMITTEE MEMBER

COMMENTS ON BC HYDRO'S

AUGUST 2013 INTEGRATED RESOURCE PLAN

Prepared on behalf of the First Nations Energy and Mining Council

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October 2013

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1.0 INTRODUCTION

This document summarizes comments of the First Nations Energy and Mining Council (FNEMC) as prepared by InterGroup Consultants Ltd. on BC Hydro's August 2013 Integrated Resource Plan (IRP). InterGroup participated as members of the Technical Advisory Committee for BC Hydro's IRP on behalf of the FNEMC. Comments reflect the review of the August 2013 IRP and information presented to TAC members.

The IRP is BC Hydro's plan for obtaining the resources necessary to meet provincial electricity requirements for the next 20 years. Specific objectives for the IRP are set out in the *Clean Energy Act*. The Act requires BC Hydro to complete its IRP and submit it to the provincial government within 38 months of Part 6 of the Act coming into force[1]. The IRP review process was delayed from its original schedule due to a provincial government review of BC Hydro rates that was announced in April 2011 and other provincial policy reasons.

BC Hydro submitted the IRP to the provincial government on August 2, 2013. On August 23, 2013 the Minister of Energy and Mines wrote to BC Hydro stating that prior to any Lieutenant Governor in Council decision concerning the IRP, BC Hydro would be required to:

1. Give public notice that it has submitted the IRP and provide public access to the IRP on its website and other means.
2. Conduct a final round of consultations related to its IRP with First Nations, key stakeholders and the public. Consultation must be carried out by October 18, 2013. While the consultations should cover the IRP in its entirety, of particular interest is feedback on the changes to the IRP since BC Hydro undertook consultations in the spring and summer of 2012, on uncertainty over the 20-year period and the contingency plans BC Hydro is proposing to deal with that uncertainty.
3. By November 15, 2013, BC Hydro is to re-submit its IRP for consideration by the LGIC[2].

The IRP includes several components:

- A load forecast, which estimates how much electricity British Columbia will require over the next 20 years.
- Conservation initiatives that BC Hydro could pursue with its customers in order to reduce the amount of electricity that must be supplied.
- An evaluation of generation and transmission resources that could be acquired in order to meet the gap between existing resources and those required to serve future load growth.

[1] The Act received royal assent on June 3, 2010.
[2] Summarized from the Minister's letter dated August 23, 2013. Available: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/ministers-letter-irp.pdf. Accessed: October 9, 2013.

BC Hydro examines each of these components under different potential future market scenarios, for example high or low future economic growth. Potential generation and transmission resources are evaluated across different indicators (or attributes) including cost, environmental impacts and economic benefits. The IRP concludes with several recommendations and actions for BC Hydro to pursue.

As part of the IRP process, BC Hydro established a Technical Advisory Committee (TAC). The purpose of the TAC was to provide ongoing feedback and expert advice to BC Hydro during the development of the IRP. BC Hydro has committed to considering input and advice from TAC members in developing the IRP. However, the IRP is BC Hydro's document and BC Hydro is not bound by recommendations or advice it receives from TAC members.

BC Hydro requested that the FNEMC participate as a member of the TAC. The FNEMC retained InterGroup Consultants Ltd. to participate on the FNEMC's behalf and to provide the FNEMC with a summary of comments and analysis following each TAC meeting. TAC meetings were held on December 14, 2010; January 27-28, 2011; February 14, 2011; April 5-6, 2011; February 28-29 2012; June 18 2012 and September 23, 2013.

BC Hydro has requested that TAC participants provide public comments on the August 2013 IRP. BC Hydro's draft IRP contains seventeen recommendations: nine recommendations on the Base Resource Plan; four recommendations on the LNG Base Resource Plan and four recommendations on the Contingency Resource Plan. This document summarizes the comments of InterGroup Consultants on the seventeen recommendations in the August 2013 IRP. FNEMC previously provided comments on the May 2012 draft IRP. Many of the FNEMC's comments on the 2012 draft apply equally to the August 2013 IRP. Comments in this document therefore focus on key changes to the IRP since the May 2012 draft. The FNEMC is also providing comments on First Nation policy and process considerations under separate cover.

2.0 SUMMARY OF IRP CHANGES SINCE MAY 2012 DRAFT IRP

There have been a series of changes incorporated into the August 2013 IRP when compared to the May 2012 draft IRP. Many of these changes have been driven, at least in part, by changes to provincial government policies. BC Hydro provided TAC members with a table summarizing key changes to the energy load-resource balance. The key changes include:

1. In the May 2012 Draft IRP, BC Hydro noted that until February 3, 2012, the Electricity Self-Sufficiency Regulation required BC Hydro to plan for self-sufficiency based on what BC Hydro's Heritage resources are capable of producing in the lowest water flows on record, known as "critical water conditions". In 2012, this planning requirement was changed to "average water conditions", which had the effect of reducing the need for firm energy by about 4,100 GW.h per year[3].

2. As part of the 2013 IRP, BC Hydro made certain changes to assumptions about IPP volumes, timing and attrition. This resulted in some changes to the load resource balance.

3. The 2013 IRP includes updates to the load forecast (using the 2012 load forecast as opposed to the 2011 load forecast used as the basis for the May 2012 IRP). This results in a lower overall supply requirement.

4. BC Hydro's 2013 IRP recommends adopting a number of actions to manage energy supply in the short- to mid-term including reducing spending on energy purchase agreements (EPAs) by deferring, downsizing or terminating pre-delivery EPAs, re-evaluating spending on EPA renewals and minimizing acquisition of new EPAs; delaying ramp-ups in spending on DSM activities and scaling back on voltage and var optimization project implementation. These measures have the effect of reducing the forecast energy supply in the short to medium term.

5. BC Hydro has also adjusted the forecasts that include LNG loads. This reduces the forecast demand in the LNG scenarios by between 2,300 to 3,800 GW.h annually.

Table 1 summarizes these changes with and without LNG loads. Key implications of these changes include:

- BC Hydro's 2013 IRP shows an energy surplus (without LNG) of 5,041 GW.h in F2017, 2,180 GW.h in F2021 and 284 GW.h in F2026. This contrasts with the 2012 Draft IRP where the near-term energy surplus (without LNG) was 3,039 GW.h in F2017, 346 GW.h in F2021 and an energy deficit of 2,087 in F2026.

- BC Hydro's 2013 IRP shows an energy surplus (with LNG) of 5,041 GW.h in F2017, 180 GW.h in F2021 and a deficit of 2,715 GW.h in F2026. This contrasts with the 2012 Draft IRP where the near-term energy deficits (with LNG) were 761 GW.h in F2017, 4,935 GW.h in F2021 and 7,367 in F2026.

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[3] Page 1-13. May 2012 Draft IRP.

Table 1:
System Annual Energy Load Resource Balance After DSM
2012 Draft IRP Compared to 2013 IRP (GW.h)[4]

	F2017	F2021	F2026	F2031
Energy Surplus/Deficit Without LNG				
2012 Draft IRP with Critical Water	**-1,061**	**-3,754**	**-6,187**	**-11,297**
add: Change to Average Water Planning Criterion	4,100	4,100	4,100	4,100
2012 Draft IRP with Average Water	*3,039*	*346*	*-2,087*	*-7,197*
add: Updates to IPP Volume, Timing, Attrition	403	614	978	447
less: Reductions from 2011 Load Forecast to 2012 Load Forecast	-3,471	-1,446	-1,032	-2,679
add: Energy Supply Management Actions	-1,872	-226	361	764
2013 IRP Energy Surplus/Deficit	**5,041**	**2,180**	**284**	**-3,307**
Energy Surplus/Deficit With LNG				
2012 Draft IRP with Critical Water	**-4,861**	**-9,035**	**-11,467**	**-16,578**
add: Change to Average Water Planning Criterion	4,100	4,100	4,100	4,100
2012 Draft IRP with Average Water	*-761*	*-4,935*	*-7,367*	*-12,478*
add: Updates to IPP Volume, Timing, Attrition	403	614	978	447
less: Reduction from Initial LNG to Expected LNG	-3,800	-3,281	-2,281	-2,281
less: Reductions from 2011 Load Forecast to 2012 Load Forecast	-3,471	-1,446	-1,032	-2,679
add: Energy Supply Management Actions	-1,872	-226	361	764
2013 IRP Energy Surplus/Deficit	**5,041**	**180**	**-2,715**	**-6,307**

In general, BC Hydro's 2013 IRP shows near term energy surpluses (both with and without LNG loads) through at least F2021. Other key changes in the 2013 IRP relative to the 2012 draft IRP include:

1. BC Hydro has updated the cost estimates for Site C, with the overall effect of lowering the unit energy cost at the point of interconnection from $95/MW.h ($2011) to $78/MW.h ($2011)[5].
2. BC Hydro is no longer recommending pursuing more aggressive DSM program spending.
3. BC Hydro is no longer recommending developing energy procurement options to acquire up to 2,000 GW.h per year from clean energy producers in the F2017 to F2019 time frame.

[4] Source: information provided by BC Hydro to TAC members by email dated October 9, 2013.
[5] 2013 UECs are taken from page 3-47 of the 2013 IRP and are based on capital costs of $7.9 billion referenced to the Site C EIS submission. 2012 UECs are taken from page 3-37 based on capital cost of $7.9 billion included in the 2011 Site C Project Description Report. The capital costs do not have appeared to change, but the 2011 Site C project description notes a discount rate of 5.5 to 6.0 per cent at page 45 while the 2013 IRP cites a discount rate of 5.0 per cent at page 3-47.

BC Hydro's 2013 IRP contains recommendations for the base resource plan (without LNG), the base resource plan including LNG and a contingency resource plan. Comments are provided on recommendations associated with each of these plans in the following sections.

3.0 BASE RESOURCE PLAN

BC Hydro's Base Resource Plan is expected to result in the following Load Resource Balances (after conservation initiatives and before expected LNG):

1. Sufficient existing annual energy supply to meet energy requirements through to approximately F2025. Following recommended actions, sufficient energy supply to meet energy requirements to approximately F2033.

2. Sufficient existing capacity supply to meet capacity requirements through to approximately F2021. Following recommended actions, sufficient capacity supply to meet capacity requirements through F2033[6].

3.1 COMMENTS ON BC HYDRO RECOMMENDED ACTIONS

Recommended Action #1: Moderate current DSM spending and maintain long-term target. Target expenditures of $445 million ($175 million, $145 million, and $125 million per year) on conservation and efficiency measures during F2014 to F2016. Prepare to increase spending to achieve 7,800 GWh/year in energy savings, and 1,400 MW in capacity savings by F2021.

BC Hydro recommends reducing near term demand side management (DSM) expenditures while maintaining the ability to ramp back up DSM programming in the future. BC Hydro states that the planned adjustments to DSM program activities and expenditures in the near term result in potential savings of $330 million relative to maintaining currently planned DSM program expenditures. BC Hydro also notes these reduced expenditures will result in almost 900 GWh/year of lower cumulative DSM energy savings by F2021. BC Hydro states in developing plans for these reduced expenditures while maintaining the ability to ramp up in the future, it considered the following principles:

1. Eliminate projects or activities that have short energy savings persistence and thus only contribute to the near-term surplus period.

2. Consider "lost opportunities" by a) continuing to offer incentives for energy savings opportunities that will not be available in the future and b) defer incentives for energy savings opportunities that are not needed now but will have a predictable update regardless of when they are offered.

3. Maintain program activities to retain a level of customer and trades engagement and relationships so that DSM programs can be ramped up to long-term savings targets as needed.

4. Consider cost-effectiveness of DSM programs from both the UC and TRC perspectives.

5. Consider broad opportunities for customers to participate[7].

[6] Summarized from figures 8-3 and 8-4 on pages 8-46 and 8-47 of the August 2013 IRP.
[7] Summarized from page 8-16 of the August 2013 IRP.

This recommended action contrasts sharply with the recommendation from the May 2012 IRP where BC Hydro recommended more aggressive DSM programming and spending relative to currently planned targets. There is a risk that BC Hydro will send mixed messages to consumers about the importance of conservation initiatives and that uptake of future conservation programs will be compromised.

Also, as noted in comments on the May 2012 draft IRP, access to conservation programming continues to be an issue for many First Nations. First Nations continue to be underserved by current DSM programming. Consistent with BC Hydro's stated principle that it will "consider broad opportunities for customers to participate", BC Hydro should ensure its reduced DSM program spending does not compromise its ability to develop and implement options and programs that are accessible and appropriate for First Nations. This is particularly important for remote communities where the marginal cost of generation is substantially higher than on the integrated electricity system.

As noted in the FNEMC August 2012 comments, relevant considerations in this regard include:

- In First Nations communities housing costs and electricity bills may be paid by the Band and not the individual or family residing in the home. Therefore, conservation programs involving financial incentives/assistance for repairs and upgrades or reduced electricity bills may not be as effective as in other communities.

- Access to capital dollars for repairs and improvements to community facilities (both residential and commercial) may be limited compared to other communities.

- Codes and standards applicable in First Nations communities may differ from provincial standards.

In recognition of the specific challenges associated with conservation/DSM initiatives in First Nations communities, BC Hydro and the Province of British Columbia should provide capacity funding for energy managers to support energy conservation in First Nations communities. First Nations should be directly engaged in the design and delivery of conservation programs. Such programs should be focused on incentives rather than penalties. Program design should address specific needs of rural or off-grid First Nations; recognize the need for business and economic development on First Nation lands and ensure accessibility for lower and fixed income people.

Recommended Action #2: Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term. Pilot voluntary capacity-focused programs (direct load control) for residential, commercial and industrial customers over two years, starting in F2015.

BC Hydro's load-resource balance indicates a capacity deficit in approximately F2021. BC Hydro notes that other jurisdictions have established practices of relying on long-term load curtailment for peaking capacity and some forms of operational reserve. However BC Hydro also notes that to date BC Hydro has had experience with load curtailment programs for large industrial customers but these programs have not resulted in a long-term commitment either by BC Hydro to acquire load curtailment or customers to interrupt or adjust operations when and as required.

BC Hydro proposes to design and launch a voluntary load curtailment offer and capacity focused programs starting in F2015. BC Hydro notes that capacity focused measures have the potential to reduce the need for bridging resources such as market purchases and power from the Columbia River Treaty. BC Hydro also indicates these pilot programs will provide the opportunity for BC Hydro to evaluate whether to rely on capacity focused DSM as a long-term capacity resource[8].

Based on the information provided, BC Hydro's recommended action seems reasonable. Other observations noted as part of the comments provided on the May 2012 draft IRP that are still relevant include:

- The voluntary nature of these programs is important. BC Hydro should focus on developing and implementing voluntary programs and rate options that share the benefits of cost savings with customers that choose to participate.
- As with the energy focused DSM programs, access to these programs is important. BC Hydro should ensure cost-effective capacity reduction programs are accessible in First Nations communities as well as to residential, commercial and industrial customers.
- Any mandatory rate measures should focus on incentives rather than punitive rates for residential and rural users.

Recommended Action #3: Explore more codes and standards. Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost and to gain knowledge and confidence about their potential to address future or unexpected load growth.

BC Hydro notes there may be opportunity to leverage additional levels of DSM related to codes and standards with the potential to deliver a substantial amount of cost-effective electricity savings. However, there is considerable uncertainty regarding implementation and achievement of these additional electricity savings. The costs associated with this action are anticipated to be approximately $1.5 million per year from F2015 to F2016. BC Hydro indicates it will design and manage these activities to achieve enhanced certainty at a reasonable cost[9].

Potential costs associated with these actions appear small and to the extent BC Hydro can implement these measures in a manner that enhances their certainty, and does not unduly impact First Nation or residential customer rates, this recommendation appears reasonable.

Recommended Action #4: Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.

[8] Summarized from pages 8-20 to 8-21 of the August 2013 IRP.
[9] Summarized from pages 8-22 to 8-23 of the August 2013 IRP.

BC Hydro notes an adequate energy supply until F2027 and is therefore undertaking time-critical actions over the next few months to prudently manage the costs of energy resources it has acquired, committed to or planned over the next five years. These actions include:

1. Termination of Pre-COD EPAs: BC Hydro indicates it has or is seeking to execute mutual agreements to terminate EPAs with IPPs where development has stalled.
2. Deferral of additional supply: BC Hydro notes it is continuing to discuss options for deferral or downsizing of EPAs with developers where feasible options exist.
3. EPA Renewals: BC Hydro indicates IPP projects will be individually assessed as EPAs come up for renewals.

BC Hydro indicates it will continue to negotiate in good faith with First Nations where agreements are in place committing BC Hydro to negotiate EPAs.

This recommendation is of particular concern from a First Nation perspective. First Nations have been successful developers and partners in many IPP projects that supply clean and renewable energy. There is a material risk from this recommendation that BC Hydro will reduce confidence in its commitment to developing clean and renewable energy in the IPP sector and with First Nations. Specific comments on this recommendation include:

- To the extent BC Hydro can execute mutually beneficial agreements to both parties to EPAs to delay or downsize IPP project energy deliveries, these are reasonable measures to pursue. Key to this recommendation is that the agreement benefits, the IPP developer, BC Hydro and any affected First Nations.
- BC Hydro should prioritize retaining and renewing EPAs where First Nations are the main IPP developer or major partners in the IPP development.

Recommended Action #5: Investigate incentive-based pricing mechanisms over the short-term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro's service area.

BC Hydro indicates that domestic rates are higher than the price that can be obtained on the spot market; higher value for surplus energy can be obtained by increasing domestic demand. BC Hydro notes this is worthwhile only if the increased load is temporary and there is benefit to the initiative[10].

To the extent surplus energy in the short- to medium-term can be sold to domestic customers at a price higher than spot market or short-term export prices there is merit to this recommendation. However, there are concerns that any domestic loads serviced will not truly be "temporary". Experience in other jurisdictions has shown that truly interruptible electricity rates for domestic customers either need to be heavily discounted relative to full-tariff rates or that uptake of interruptible electricity will be low.

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[10] Summarized from pages 8-26 to 8-27 of the August 2013 IRP.

Recommended Action #6: Continue to advance Site C. Build Site C to add 5,100 GW.h of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date of F2024 subject to: environmental certification; fulfilling the Crown's duty to consult and where appropriate accommodate Aboriginal groups; and Provincial Government approval to proceed with construction.

BC Hydro states there is a need for Site C based on an energy gap beginning in F2027 without LNG load and F2022 with LNG load and a capacity gap beginning in F2021 without LNG load and F2020 with LNG load. BC Hydro indicates it is difficult to precisely time the addition of new electricity resources due to a number of uncertainties. BC Hydro states that Site C is cost effective compared to a comparable clean generation block of viable clean or renewable alternatives ($94/MW.h delivered to the Lower Mainland compared to $153/MW.h). BC Hydro also notes Site C is cost effective compared to the clean plus thermal generation block (Revelstoke Unit 6 and six single cycle gas turbines) at $94/MW.h compared to $128/MW.h.

BC Hydro notes it is engaged in consultation with Aboriginal groups that will continue through all stages of Site C. BC Hydro states it has concluded 13 consultation agreements with 16 First Nations to date and others remain under discussion[11].

Comments on Site C were provided following the review of the 2012 draft IRP. Many of the comments from that submission remain relevant today. FNEMC does not support the inclusion at this time of Site C. FNEMC and First Nations have expressed concern since the inception of the BCUC Section 5 Inquiry and repeated throughout the IRP process that the approved IRP will be used by Hydro and government to justify particular projects and reduce or eliminate normally required rigorous scrutiny. Inclusion of Site C at this stage is inconsistent with the concept that the IRP is to provide overall direction, but not to approve individual projects. Site C has been studied considerably more than other potential resource options. It has also already received attention from legislators and regulators (including being exempted from the requirement for a certificate of public convenience and necessity under the *Clean Energy Act*). The degree to which Site C has already been advanced highlights several challenges associated with the IRP process:

- **Conflicts between provincial level planning and regional/local environmental impacts:** Site C highlights the conflict between provincial level energy planning and regional environmental impacts. In order to develop Site C, local First Nations and communities would be asked to bear significant impacts on lands and water. No decisions or plans to advance Site C should be made without meaningful consultation and accommodation with First Nations whose lands and waters would be impacted.

- **Benefits must be shared:** If Site C is to be developed in a manner that is acceptable to the impacted First Nations and communities, mechanisms must be in place to ensure the economic benefits of the project are shared fairly with the local First Nations and communities. Benefit sharing must extend beyond simply offering short-term construction-related employment to local residents.

[11] Summarized from pages 8-28 to 8-39 of the August 2013 IRP.

Revenue sharing and project ownership must be included as benefits for local First Nations and communities. Best practices from other Canadian jurisdictions should be reviewed and incorporated into project planning and development.

Recommended Action #7: Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.

Based on developing Site C by F2024, BC Hydro notes there is a three-year capacity gap without LNG from F2021 to F2023. To address this gap, BC Hydro proposes to rely on the market (power purchases) backed up by the Canadian Entitlement provided under the Columbia River Treaty for up to 200MW. BC Hydro notes this approach is beneficial to ratepayers12. FNEMC continues to support using power from the Columbia River Treaty prior to market purchases.

This recommendation is based on an assumption of Site C being built with an inservice date of F2024. To the extent BC Hydro is unable to develop Site C alternative sources of capacity would be required.

Recommended Action #8: Advance reinforcement along existing GMS-WSN-KLY 500kv transmission.

and

Recommended Action #9: Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.

These recommendations reflect requirements for system transmission upgrades identified in the IRP analysis. Both projects would require a certificate of public convenience and necessity in the event costs are expected to be greater than $100 million[13]. These recommendations appear prudent from a planning perspective, subject to BC Hydro obtaining the necessary environmental and regulatory approvals and ensuring First Nations are consulted and accommodated.

[12] Summarized from pages 8-39 to 8-40 of the August 2013 IRP.

[13] Summarized from pages 8-41 to 8-45 of the August 2013 IRP.

4.0 LNG BASE RESOURCE PLAN

In addition to the Base Resource Plan, BC Hydro also considered incremental actions that would be required to address expected LNG requirements (approximately an additional 3,000 GW.h and 360 MW by F2022)[14]. BC Hydro's Base Resource Plan is expected to result in the following Load Resource Balances (after conservation initiatives and including expected LNG):

1. Sufficient existing annual energy supply to meet energy requirements through to approximately F2019. Following recommended actions sufficient energy supply to meet energy requirements to approximately F2033.
2. Sufficient existing capacity supply to meet capacity requirements through to approximately F2021. Following recommended actions, sufficient capacity supply to meet capacity requirements through F2033[15].

4.1 COMMENTS ON BC HYDRO RECOMMENDED ACTIONS

Recommended Action #10: Working with industry, explore natural gas supply options on the north coast to enhance transmission reliability and to meet expected load.

BC Hydro characterizes this action as advancing work to determine where and how natural gas fired generation could be built to reduce project lead times and to be able to meet LNG load requirements as required. BC Hydro notes the decision on whether to proceed beyond exploring options would be pursuant to completion of supply agreements between BC Hydro and LNG proponents. BC Hydro proposes to conduct technical studies that would take approximately one year to complete at an estimated cost of $0.5 million. BC Hydro notes at present it does not need to commit to the type and quantities of natural gas generation required to maintain or enhance North Coast supply reliability[16].

It should be noted that in its May 2012 draft IRP, BC Hydro stated there has been little to no greenfield gas generation project development work in BC in decades and therefore siting of potential gas generation is a substantial issue[17].

The costs associated with this recommendation are small in the short-term and appear reasonable to preserve flexibility. Prior to any developments being advanced, impacts on local airsheds would need to be examined and First Nations would need to be consulted and accommodated.

Recommended Action #11: Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.

[14] Page 2-2. August 2013 Integrated Resource Plan.
[15] Summarized from figures 8-5 and 8-6 on pages 8-61 and 8-62 of the August 2013 IRP.
[16] Summarized from pages 8-52 to 8-54 of the August 2013 IRP.
[17] Page 9-73. BC Hydro Draft Integrated Resource Plan. May 2012.

BC Hydro notes it has sufficient energy to be able to supply expected LNG loads without acquiring additional clean or renewable energy resources. However, there is uncertainty with the size of potential LNG load and therefore BC Hydro proposes to advance work on developing energy acquisition processes in a staged manner. BC Hydro states it will not launch an acquisition process until a clear need has emerged and anticipates funding to ensure acquisition processes are ready to be launched as required range from $50,000 to $500,000[18].

The costs associated with this recommended action are small and appear reasonable. In the event BC Hydro does go forward with another clean power procurement process, it should design such a process to address recommendations from the review of its procurement practices, in particular:

- Make the energy procurement process more transparent for all stakeholders.
- Implement smaller but more frequent energy procurements in the future[19].

Further recommendations include:

- BC Hydro should prioritize future procurement from projects with a First Nation partnership or ownership structure.
- Any unused or undeveloped water licenses should revert to the local First Nation.
- Attention should be paid to facilitating net-metering to encourage smaller scale development of local generation sources.

Recommended Action 12: Advance reinforcement of the 500kv transmission line to Terrace.

BC Hydro states the purpose of this project is to increase transfer capacity of the existing 500 kV transmission circuit to increase the ability to serve potential LNG and mine loads. BC Hydro indicates a final investment decision by the customer is expected to occur by the end of F2015. BC Hydro notes it is in the process of consulting with First Nations with respect to this project[20]. It appears this recommendation is dependent on a positive investment decision from potential LNG or other industrial customers in the area. The FNEMC has taken no position on the LNG facilities and is not opposed i principle to supplying them with electricity, however transmission costs should be carried by the developers, not general customers.

Recommended Action 13: Continue discussions with BC's northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.

BC Hydro notes that the pace of expansion in the Horn River Basin has slowed considerably due to low gas prices and generally poor economic conditions. However, to maintain options to electrify this region

[18] Summarized from pages 8-54 to 8-55 of the August 2013 IRP.
[19] Final Report on BC Hydro's Energy Procurement Practices. Merrimack Energy Group. 2011.
[20] Summarized from pages 8-56 to 8-57 of the August 2013 IRP.

BC Hydro is recommending monitoring natural gas industry developments and engaging with industry to maintain the potential for supply alternatives. BC Hydro notes the costs associated with this recommendation are approximately $50,000 to $100,000 over the next three years and that no material regulatory approval processes are required for this recommended action[21]. The costs associated with this recommended action are small in the short term. However, given the potential for dramatic environmental and social changes associated with future electricity development in this region, BC Hydro must ensure it engages with First Nations early in any planning processes for future developments.

[21] Summarized from pages 8-57 to 8-60 of the August 2013 IRP.

5.0 CONTINGENCY RESOURCE PLANS

BC Hydro states that it undertakes contingency planning to manage the risks and consequences of not being able to meet loads should the base resource plan not materialize as expected. BC Hydro notes the aim of the CRPs is not to build the resources in the portfolios but to reduce the lead time for supply-side resources if the need arises. BC Hydro included two CRPs in its August 2013 IRP, one addressing contingencies without expected LNG Load and one with expected LNG loads.

5.1 COMMENTS ON BC HYDRO RECOMMENDED ACTIONS FOR CRP 1

BC Hydro has identified three recommended actions to address contingencies for uncertainties in load-resource balances without expected LNG loads. BC Hydro's recommended actions are capacity focused, though BC Hydro notes the potential for energy supply shortfalls that may advance the requirement for future clean energy acquisitions[22].

Recommended Action 14: Advance Revelstoke Unit 6 Resource Smart Project to preserve its earliest in service date of F2021.

and

Recommended Action 15: Advance Resource Smart upgrades at GM Shrum Generating Station Units 1-5 with the potential to gradually add up to 220 MW of peak capacity starting in 2021.

BC Hydro indicates Revelstoke Unit 6 would add 488 MW of long-term dependable capacity. BC Hydro indicates it will spend up to $7.2 million between F2014 and F2016 to ensure Revelstoke Unit 6 is available for its earliest in service date. BC Hydro states that work would be contained within the existing footprint of the Revelstoke GS.

BC Hydro states a capacity increase of units 1-5 at GM Shrum Generating Station could provide 220 MW of dependable capacity. Spending in F2015 and F2016 is forecast to be between $700,000 to $800,000. These projects were identified as the lowest cost capacity resources in section 6.9 of the IRP[23].

It appears these projects are reasonable contingency options in the event additional capacity is required on the BC Hydro system.

Recommended Action 16: Investigate natural gas generation for capacity.

BC Hydro proposes to undertake work to develop natural gas-fired options that focus on reducing lead times and understanding where and how to site natural gas fired generation. BC Hydro states First Nation engagement and consultation will be a key consideration for analysis and design of potential procurement processes. BC Hydro indicates it will seek to find ways to share risks with IPPs to develop the resources

[22] Summarized from pages 8-74 and 8-75 of the August 2013 IRP.
[23] Summarized from pages 8-65 to 8-71 of the August 2013 IRP.

to a shelf-ready status and avoid committing to major expenditures prior to need being confirmed. It appears this is a reasonable contingency option in the event additional capacity is required.

5.2 COMMENTS ON BC HYDRO RECOMMENDED ACTIONS FOR CRP 2

BC Hydro has identified one further recommended action to address contingencies for uncertainties in load-resource balances with expected LNG loads. BC Hydro's recommended action is primarily capacity and transmission focussed.

Recommended Action 17: Fort Nelson area supply options.

BC Hydro notes that it must be prepared to address potential loads in the Fort Nelson area in the event they arise. BC Hydro recommends a number of options including monitoring Fort Nelson area load growth and investigating a range of supply options. Key activities noted in the IRP include completing design and implementation of a Load Shedding Remedial Action Scheme that will allow BC Hydro to serve increased load on an interruptible basis (estimated cost of $2 million) and refining options to meet the range of forecast capacity shortfalls (estimated cost of $50-$100,000)[24]. Development of this scale in the Fort Nelson area raises environmental and social planning issues beyond simply supplying the development with electricity. If these developments emerge the province must ensure First Nations are consulted and accommodated.

[24] Summarized from pages 8-77 to 8-79 of the August 2013 IRP.

6.0 COMMENTS ON ADDITIONAL IRP RECOMMENDATIONS

BC Hydro includes the following additional recommendations in the IRP:

- **Province-wide Electrification:** BC Hydro notes the costs and impacts of general electrification would be significant and proposes to undertake low-cost preparatory actions including analysis of where electrification would be expected to occur in response to strong climate policy; continuing distribution system studies in conjunction with smart meter and smart grid implementation and ongoing efforts to monitor provincial, national and international climate policy developments.
- **Export Market:** BC Hydro's key conclusion is that market conditions do not justify the development of new, additional clean or renewable resources for the export market.
- **Transmission planning for Generation Clusters:** BC Hydro's analysis indicates there may be the potential to somewhat reduce environmental footprints but only a marginal financial benefit associated with developing clusters to meet customer demand. BC Hydro notes it will consider transmission advancement for generation clusters during acquisition processes.

These recommendations are consistent with the load and market scenarios evaluated by BC Hydro in the IRP and appear reasonable.

7.0 COMMENTS ON PROCESS AND NEXT STEPS

The FNEMC is also providing comments on First Nation policy and process considerations under separate cover. The review process contemplated by the province, and the decisions or actions that may flow from any approvals are not clear. The provincial government should provide timelines for review of the IRP and clearly communicate, to the public and participants in the IRP process, the decisions and actions that will follow approval of the IRP.

Finally, BC Hydro notes that the submission date for the next IRP is August 2018 unless a submission date is prescribed by LGIC regulation. BC Hydro notes that the Clean Energy Act enables BC Hydro to submit an amendment to an approved IRP. BC Hydro notes that the decision to submit an amendment prior to the next IRP will depend on a number of factors including LNG final investment decisions, changes to BC government policy, significant load forecast changes or other issues that may require First Nations consultation and stakeholder input. It is recommended that BC Hydro develop processes for ongoing engagement of First Nations on resource planning issues between formal reviews of the IRP.

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Introduction

The British Columbia Public Interest Advocacy Centre is legal counsel for a collection of community groups who together represent the interests of British Columbia's low and fixed income residential utility ratepayers. The community groups we represent in this process are: British Columbia Pensioners' and Seniors' Organization, Tenant Resource and Advisory Centre, BC Coalition of People with Disabilities, Active Support Against Poverty Housing Society, Council of Senior Citizens' Organizations of BC, and Together Against Poverty Society. In this submission, we refer to these groups collectively as "BCPSO". BCPSO regularly intervenes in proceedings before the BC Utilities Commission, and has a long history of engagement with BC Hydro's resource planning processes.

As a representative of low and fixed income residential rate payers, our primary focus in on keeping rates low. We take as our starting point the fact that electricity is a basic necessity, without which British Columbians cannot live healthy and productive lives. We understand that many British Columbians already live in a state of "electricity poverty" -- the inability to afford the electricity necessary to meet daily living requirement – and that increasing numbers of British Columbians are likely to fall into this category as electricity rates increase.

Three factors contribute to electricity poverty: the unit cost of electricity, the efficiency of homes and electrical appliances, and household income. BC Hydro's Integrated Resource Plan deals directly with the first two factors: the unit cost of energy and the ability of low income ratepayers to use electricity efficiently.

Financial Impact of Government Policies

We note first that BC Hydro is operating within a legislative regime which significantly restricts its access to low cost resource options. BC Hydro has taken these restrictions to heart in its IRP and has only evaluated resource options that are available under the current legislative regime. In our view, this is an error for two reasons. First, government policy and legislation change frequently. By failing to evaluate options that are currently prohibited by legislation, BC Hydro will not be well placed to shift gears quickly when government policy and legislation change, as it inevitably will. Second, by failing to evaluate alternatives currently prohibited by legislation, BC Hydro has deprived government policy makers and utility ratepayers of the ability to understand the cost implications of government policy decisions. This inability to evaluate the cost of provincial policy extends to the very significant potential ratepayer costs associated with BC's self-sufficiency and clean/renewable energy requirements, as well as provincial policy around connecting natural gas operations (extraction and export) to the grid and, eventually, to the "general electrification" of the province. In short, as a ratepayer group, BCPSO would like to know the rate impact of the various provincial energy policies.

In the current energy environment, the requirements set out in the *Clean Energy Act* to achieve energy self-sufficiency by 2016 and to generate at least 93% of the electricity in BC from clean or renewable resources appear to have the effect of significantly driving up electricity costs without substantial corresponding benefit. Recently released information indicates that BC Hydro ratepayers face a rate crisis over the near term, with rate pressures likely to moderate over the longer term[1]. In order to better assess and potentially lessen the impact of this rate crisis on its low income customers, BC Hydro should consider and evaluate all viable supply options in its resource planning process, including those currently prohibited by legislation.

According to the IRP, forecasted spot market electricity prices at Mid-C range from $25/MWh to $40/MWh over the next 20 years[2]. These low prices are, at least in part, a result of other jurisdictions pursuing policies similar to those being pursued in BC, which have resulted in large subsidies for renewable generation and a surplus of energy generation. By limiting BC Hydro's ability to rely on market purchases, BC government policy ensures that BC Hydro's ratepayers are subsidizing the production of renewable generation in BC while being prohibited from taking advantage of similar subsidies for renewable generation being provided by the ratepayers and taxpayers of other jurisdictions. It's a scenario in which utilities and ratepayers both lose, with market prices well below the cost of generation. The self-sufficiency requirement is particularly problematic in the context of the Canadian Entitlement under the Columbia River Treaty, which denies BC Hydro's ratepayers not just the ability to benefit from favourable market prices, but also from long term entitlements with a very low risk of non-delivery.

The requirement that 93% of energy generated in BC must come from "clean or renewable" resources also unduly limits BC Hydro's resource options. A ton of CO2 emitted in BC contributes no more to climate change than a ton of C02 emitted in another jurisdiction. While BC Hydro is significantly constrained in its ability to rely on natural gas fired generation, even where it is the low cost generation option, it is simultaneously able to import power from neighbouring jurisdictions generated from natural gas and coal. BC Hydro also faces potentially enormous load growth because of BC's production and export of natural gas that will be burned in other jurisdictions.

Further, the 93% clean and renewable target applies only to electricity generation, and not to gas-fired direct drive technology, gas space and water heating, or to electricity generated to serve the natural gas

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[1] Rates Working Group: Session 1, August 23, 2013

[2] IRP, p.1-7

liquefaction industry. These policies and exclusions create a mismatch between the presumed objective of reducing GHG emissions from energy production and the actual level of GHG emissions from energy production. It is also not clear that targeting electricity generation is an effective or cost-effective way to reduce provincial GHG emissions. In 2010, electricity generation accounted for only 2% of provincial GHG emissions, compared to 26% for stationary combustion sources (including heating) and 38% for transportation[3]. It appears from this that any incremental increase in GHGs from electricity production could be readily offset by, for example, changes to provincial transportation policy[4].

BCPSO is not advocating that BC Hydro rely on imported power or gas-fired generation. It is merely pointing out that part of the purpose of an integrated resource plan (IRP) -- to consider all options for meeting electricity demand – has been thwarted by BC Hydro's interpretation of Provincial energy objectives as being fixed constraints with any planning beyond their margins to be off-limits. This has resulted in an IRP that does not consider least cost options for electricity generation and does not provide ratepayers with a way to assess the cost of these policies.

Conserving First – DSM

DSM is a very cost effective option. The average TRC for Option 2 is estimated to be only $32/MWh, with a range of costs from $6/MWh to $113/MWh. The incremental average cost of Option 3 DSM is only $76/MWh[5]. These figures represent good value. Furthermore, BC Hydro has historically underspent its DSM budget and over-achieved its DSM target[6]. This suggests DSM may be an even more cost-effective resource with a greater potential for electricity savings than has historically been estimated.

Because DSM is a cost-effective resource with significant social and environmental benefits, BCPSO supports the continuation of DSM spending at the Option 3 level. In particular, BCPSO supports DSM targeted at low income residential ratepayers and is opposed to any reduction in spending in this area. While we understand that BC Hydro has an energy surplus over the next several years, individual low-income ratepayers have no such energy surplus in their homes. Continuing low income DSM programs at a high level gives individual low income ratepayers access to potentially long-term money/energy saving opportunities.

In addition, experience has shown that low income residents are a difficult group to engage in DSM programs. A number of reasons for this have been identified in research including their more limited access to customer information, more limited ability to participate in programs that are not fully funded

[3] Industrial Electricity Policy Review Task Force Interim Report, October 4, 2013, p.5
[4] For example, the costly Gateway Project is expected to significantly increase GHG emissions from transportation. See: Environment Canada (2007). Port Mann \ Highway 1 – Environmental Assessment (EA) Review Environment Canada's Comments on Project Application. p. 2
[5] BC Hydro Draft 2013 Residential Inclining Block Rate Re-Pricing Application, p.1-17
[6] EN6 Demand Side Management 2011 http://www.bchydro.com/about/accountability_reports/2011_gri/f2011_environmental/f2011_environmental_EN6_2.html); BC Hydro Report on Demand Side Management Activities for the 12 Months Ending March 31, 2012; BC Hydro Report on Demand Side Management Activities for the 12 Months Ending March 31, 2013

by the utility, needs that differ in degree or complexity compared to other customer groups, more limited control over energy efficiency factors in their living environments, difficulties experienced by utilities in making contact via traditional channels, and complex participation requirements. Because low income customers are more difficult to engage and re-engage, we believe it is important for engagement efforts to continue without reduction in the short term

BCPSO also supports the implementation of voluntary load curtailment and voluntary direct load control programs. BCPSO further believes that BC Hydro should assume for planning purposes that it will successfully achieve some capacity savings from capacity-focused DSM programs. This is a reasonably low risk assumption because BC Hydro has available to it low-cost bridging options, which it can access in the even no capacity savings materialize.

BCPSO also supports BC Hydro's continued exploration of opportunities to leverage codes and standards, as these have the potential to produce low cost DSM benefits.

Managing Resources

BCPSO supports a more aggressive approach to the cancellation or deferral of IPP contracts where cancellation or deferral is the most cost-effective option (e.g., taking into account litigation risk, damages for breach of contract, etc.). BC Hydro is oversupplied with unnecessary, high cost IPP power, apparently as a result of now abandoned government policy. The rate impact of IPP power has already been significant and will continue to escalate through 2018[7]. The greater the extent to which this expensive oversupply can be reduced, the better the outcome for ratepayers.

BCPSO also supports the case-by-case evaluation of EPAs as they come up for renewal. In no case should an EPA be renewed unless it provides a competitive product, with particular attention to capacity and reliability. BCPSO also supports changes to SOP rules to allow for better management of the electricity supply. It appears, however, that BC Hydro's recent changes to the SOP rules do not go as far as they should. For example, BC Hydro proposes to limit the participation of clustered projects over 15MW, while the Clean Energy Act sets the minimum limit at 10MW.

BCPSO opposes incentive pricing to encourage new customer loads. As noted by BC Hydro, there is substantial risk of "temporary" incentive pricing becoming permanent, as businesses become dependent on cheap power to maintain operations.

BCPSO opposes removing any future utility rate decisions from BC Utilities Commission oversight. Decision making by the Provincial cabinet over the past few years has resulted in a rapid escalation of electricity rates and rate pressures, and a series of projects that are unnecessary, ill-timed and significantly over budget. For example, the smart metering program was ostensibly to reduce electricity theft and waste. However, one questions the benefit of incurring over $1 billion for an electricity saving measure in the midst of a decade-long energy surplus with market rates hovering around $30/MWh. We note, for example, that BC Hydro has proposed delaying deployment of in-home devices designed to

[7] Rates Working Group: Session 1, August 23, 2013, p.

encourage more efficient energy use because of its surplus position. It appears delaying the entire smart meter project by 10 years would likely have resulted in greater value.

Powering Tomorrow

In principle, BCPSO supports building Site C in order to add relatively low-cost, dependable, publicly-owned power and capacity that meets provincial energy objectives. However, BCPSO does not believe current conditions warrant construction and supports delaying the project to a later in-service date.

According to the IRP, delaying the project for 2 years (to F2026) provides additional economic benefits above those forecast for an F2024 in service date. As discussed below, there is reason to believe further delaying Site C's in-service date would provide even greater benefits. The ready supply of low-cost power in the market ameliorates any potential concerns about BC Hydro's ability to meet load in the interim. Further, there is significant uncertainty in the load forecast with respect to both the rate and level at which increased load will materialize, as well as with respect to government policy for meeting that load (e.g., increased allowance for use of natural gas generation). Forecasting load is further complicated by the fact that existing customers may leave the system as rates increase. This issue was raised at the September 23, 2013 TAC meeting at which representatives of industrial and commercial customers indicated that self-generation is quickly becoming competitive with buying from BC Hydro.

In addition, given market forecasts, BCPSO opposes BC Hydro generation for the purposes of export for the foreseeable future. Although the IRP addresses this question directly, and BC Hydro also comes to the conclusion that there are no cost effective opportunities to generate electricity for export, they do not address the apparent existing export. For example, in BC Hydro's 2013 Annual Report "domestic sales" appears to include "sales to others" which includes sales to parties located outside BC pursuant to long-term contracts. BC Hydro needs to consider the wisdom of pursuing immediate construction of the Site C dam when there may be an alternative option to reduce "domestic sales" through the expiration or cancelation of existing contracts for electricity export.

With respect to the relative cost of Site C power, at page 6-31 of the IRP, BC Hydro compares Site C to blocks of portfolios of clean generation and portfolios of clean + thermal generation that provide energy and capacity comparable to that provided by Site C. However, this comparison is inappropriate because Site C is expected to oversupply for the first several years of operation. Accordingly, it would make more sense to compare Site C costs to the cost of providing alternative portfolios of energy and capacity in amounts that are expected to be needed to meet load. That is, there is no need to compare the cost of oversupply with the cost of oversupply when it is possible to bring non-Site C generation on line in smaller increments and avoid oversupply.

It is also worth noting that Site C gains an advantage over alternative portfolios in large part because of its lower WACC, which is assumed to be 5%, as compared to 6% for IPPs. Given that BC Hydro's current and anticipated ROE is 11.84%[8] with an equity thickness of 30%, we question the accuracy of a 5% WACC over the long term.

BCPSO also notes that the environmental analysis of Site C versus alternative portfolios is very incomplete. For example, the footprint for Site C and Run of River includes fuel collection, but fuel collection isn't included for biomass or gas fired generation (p.6-50). Site C is noted to have the lowest GHG emissions during operation, but there is no information in the IRP on GHG emissions associated with Site C construction. These deficiencies make an apples-to-apples comparison of environmental impacts impossible.

BCPSO strongly supports the pursuit of bridging options for capacity via market purchases and the Columbia River Treaty, and believes this strategy could be safely extended beyond the level proposed by BC Hydro. Market purchases, and especially those backed by the Columbia River Treaty, are a cost effective, low risk strategy for meeting the projected short term capacity gap. In the event Site C is built -- preferably with an in-service date later than 2024 -- BC Hydro will again have a power supply surplus. It makes no sense to build alternative generation (run of river, natural gas fired, etc.) to fill the short term gap prior to Site C's in service date.

Supporting LNG

BCPSO agrees that the exemption of LNG from the 93% clean and renewable requirement provides an opportunity for BC Hydro to use cost effective natural gas generation on the north coast. BCPSO supports further investigation of this option as an alternative to electrification.

BCPSO does not support the addition of greenfield clean or renewable IPP generation to supply LNG loads. These projects have proven to have a very high cost relative to other supply options. LNG loads can be served much more cost effectively with natural gas fired generation and this is the preferred option of BCPSO.

BCPSO agrees with the recommendation to continue discussions and study, without taking any costly steps toward electrification of the Horn River Basin or the northeast gas industry. There is too much uncertainty of load and too high a risk of stranded assets to proceed with electrification at this time.

Sincerely,
BC Public Interest Advocacy Centre

Original signed in file

Tannis Braithwaite
Barrister & Solicitor

[8] Direction No. 3 to the BC Utilities Commission, s.3(1)(f)

WRITTEN SUBMISSION FROM:

BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION

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Comments on BC Hydro's 2013 Integrated Resource Plan by the BC Sustainable Energy Association

by Thomas Hackney, Policy Director, 18 October 2013

These are the comments of the BC Sustainable Energy Association (BCSEA) on BC Hydro's 2013 Integrated Resource Plan (IRP). They are directed to BC Hydro's Technical Advisory Committee (TAC), of which BCSEA is a member. They are also directed to the Minister of Energy, to whom BC Hydro will submit the IRP for approval, as required by the *Clean Energy Act* (*CEA*).

BCSEA commends BC Hydro and its staff for their diligent efforts to carry out the extensive and complex analyses and to communicate them to the TAC members and the public. The IRP provides an essential foundation for discussing BC Hydro's resource and load issues in the long-term planning horizon.

Organization of these comments

BCSEA and its interests

BCSEA is a non-profit association of citizens, professionals and practitioners, committed to promoting the understanding, development and adoption of sustainable energy, energy efficiency and energy conservation in British Columbia. BCSEA has five chapters across BC and approximately five hundred individual and corporate members.

BCSEA is interested in the IRP as a public interest energy policy organization and as a representative of its members who are BC Hydro ratepayers and BC taxpayers who want the electricity they purchase to be from a sustainable electricity system.

Key IRP issues of concern to BCSEA members are:

- maximizing the use of energy conservation as the first and best energy resource for sustainability,

- reducing greenhouse gas (GHG) emissions,
- maximizing the use of clean and renewable supply-side energy resources, and
- maintaining a robust, cost-effective electricity system.

Summary of key points

1. BCSEA respectfully submits that the Minister should reject BC Hydro's 2013 IRP, and should refer the IRP to the Utilities Commission for a full review.

2. BCSEA is particularly concerned that there must be an independent, objective review of BC Hydro's in-house cost estimate for the Site C Project.

3. BCSEA believes that the demand-side management proposals in the 2013 IRP are inadequate, particularly in the short term. BC Hydro should plan to implement all cost-effective conservation and efficiency opportunities.

4. BCSEA respectfully encourages the government to initiate a strong, detailed action plan for BC to meet its legislated GHG reduction targets, as a necessary complement to BC Hydro's IRP.

General comment

1. Government should refer the IRP to the Utilities Commission

BCSEA respectfully submits that the government should not accept the 2013 IRP, but should instead cause the Utilities Commission to hold a full review of or inquiry into the IRP.

The 2013 IRP proposes capital spending and planning commitments that are too significant to be appropriately addressed through a process where only BC Hydro and its sole shareholder are effective participants; and the issues are complex and detailed enough that the professional due diligence of the Utilities Commission is needed.

Site C represents $7.9 billion of capital expenditures. Its development would cause other energy planning decisions, including short-, medium- and long-term reductions to energy conservation programs. BC Hydro ratepayers and other parties should be given a reasonable opportunity to have input to a plan that will affect their interests. An objective, independent review of BC Hydro's in-house cost estimate for Site C would help to establish whether the project really is cost-effective relative to other resource options.

Review of the IRP by the Utilities Commission would go far to ensure:

- public confidence and transparency in the evaluation of the IRP and its eventual acceptance or rejection,
- fairness to interested parties who would be afforded reasonable opportunities to scrutinize the IRP and express their interests,
- a high degree of diligence, expertise and objectivity in reviewing and assessing the plan, and
- a timely review of BC Hydro's energy conservation plan, which has not undergone review since the Utilities Commission's approval of an expenditure schedule in the review of the 2008 Long Term Acquisition Plan.

IRP-Specific comments (following BC Hydro's requested categories):

2. Energy conservation

BCSEA acknowledges BC Hydro for its efforts to propose an energy conservation plan to meet or exceed the objective under the *Clean Energy Act* (*CEA*) "… of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%"[1] However, BCSEA believes that BC Hydro is still "leaving money on the table" with respect to conservation savings.

In particular:

- BC Hydro proposes to pursue the Option 2 conservation plan, instead Option 3 (with higher savings), which BC Hydro proposed in the 2012 Draft IRP;
- In the short term, BC Hydro plans to ramp down conservation spending and savings, albeit hoping to recover those savings in subsequent years; and
- BC Hydro excludes conservation Options 4 and 5 from its resource modelling, and reduces spending to develop these approaches, despite their long-term potential to create transformative increases in energy conservation rates; and
- BC Hydro appears to be cutting support for technology innovation.

Option 2 versus Option 3:

In pursuing conservation Option 2 rather than Option 3, BC Hydro plans to achieve 1,100 GWh/y less of energy savings by Fiscal 2021, although the average total resource cost (TRC) for Option 3 savings is $35/MWh, well below the $88/MWh unit energy cost for Site C and BC Hydro's proposed long-run marginal cost (LRMC) of $85 - $100 /MWh.

BC Hydro offers several justifications: the delivery risk for energy conservation; a new, lower LRMC; the short-term cost benefits of reducing resource acquisitions during BC Hydro's current resource surplus.

These reasons can only be properly assessed in the context of a formal regulatory review, where interested parties able to probe topics in depth through information requests to BC Hydro.

Ramping down conservation spending:

BC Hydro plans to ramp down spending on energy conservation by $127 million (twenty-two percent) in the next three years relative to the Option 2 plan.[2] The result will be 1,500 GWh less of energy savings in Fiscal 2015, with cumulative savings planned to be recaptured to the Option 2 level by Fiscal 2021.

In justification, BC Hydro argues that its current resource surplus makes it cost effective to postpone energy conservation investments and savings. BC Hydro further claims that, in ramping down, it can minimize lost opportunities for conservation measures, and that it is confident that it can ramp savings levels back up in the future.

Again, these arguments should be reviewed through a proper regulatory process, where they can be properly tested.

Exclusion of Options 4 and 5 from modelling:

BC Hydro excludes Options 4 and 5 from modelling analysis on the basis of: "significant government and customer acceptance challenges," high cost relative to other conservation options, and uncertainty around capacity savings.[3] BC Hydro has dropped much of the discussion of Options 4 and 5 that was in the 2012 Draft IRP.

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[1] *Clean Energy Act*, section 2(b)
[2] 2013 IRP, TAC handout for Meeting #7, 23 September 2013, slide 67
[3] 2013 IRP, page 3-87

BCSEA acknowledges that it is problematic to model quantitatively where uncertainties are high; however, it is disappointing to see Options 4 and 5 dismissed with minimal discussion. These represent transformative approaches to energy conservation that could potentially cause large increases in energy conservation savings, as much as 2,000 GWh/y more than proposed in Option 2 by F2021.

The 2012 Draft IRP proposed to continue to develop Options 4 and 5, with $7 million in development expenditures over four years.[4] In the 2013 IRP, this is apparently replaced by a $1.5 million two-year commitment to explore codes and standards.[5]

BCSEA believes that conservation Options 4 and 5 should be developed and included in the portfolio modelling in the IRP.

"Supporting initiatives," which include technology innovation, are proposed to be cut "by ~ 40 per cent in the near term and then increased in F17."[6] However, the point of a technology innovation initiative is to build capacity to support new conservation initiatives as they emerge, so cutting here goes counter to the plan to ramp up savings after short-term cuts.

3. Site C and capacity resources

BCSEA believes that BC Hydro has not established the need for or cost effectiveness of the Site C Project. In particular, BC Hydro's in-house estimate of the cost of Site C has not been verified by any independent, objective body. The contents of the 2013 IRP, including of course the recommendation to proceed with Site C, depend crucially on the accuracy of the Site C cost estimate.

As well, BC Hydro provides scant analysis of the possibility and value of delaying a decision on Site C.

Both prudence and transparency demand a competent, independent review of Site C by the Utilities Commission.

Regarding capacity resources, BCSEA commends BC Hydro for its work to plan for its proportionate compliance with the *CEA* objective "to generate at least 93% of the electricity from clean or renewable resources …"[7] However, BCSEA also believes that the IRP should be expressly coordinated with achievement of British Columbia's GHG reduction targets, which are also cited in the *CEA*. The 93% standard should not be assumed to be a sufficient measure to address GHG reductions in BC Hydro's planning.

BC Hydro seems to have relied primarily on cost to determine that gas-fired capacity resources should be acquired before the Revelstoke 6 and the GM Shrum capacity projects, even though the latter are effectively GHG-free resources. BC Hydro discussed a Mica pumped storage capacity project of 500 MW installed capacity, at a price potentially competitive with that of gas-fired capacity generation. However Hydro has not indicated when this project might be ready to be included in the resource analysis. Capacity conservation projects could potentially provide over 550 MW of load reduction at a cost below that of gas-fired generation. These measures were identified in the 2012 Draft IRP, but they are still at a pre-pilot stage.[8]

[4] 2012 Draft IRP, pages 9-32 to 9-33
[5] 2013 IRP, page 8-22
[6] 2013 IRP, table, page 4-11
[7] *CEA* section 2(c)
[8] 2013 IRP, section 3.7.4, page 3-87

BCSEA believes that in the context of increasing concerns about global warming and climate change (as evidenced by the recent publication of the Fifth Assessment Report of the Intergovernmental Panel on Climate Change on the evolving science of climate change[9]), BC Hydro should put a higher priority onto developing GHG-free capacity and energy resources.

4. Independent power producer contracts and the Standing Offer Program

BCSEA supports BC Hydro's review of electricity purchase agreements with independent power producers (IPPs), where project construction has not begun. BCSEA agrees that in such reviews, consideration should be given to employment and community development objectives and to maintaining good business relations with power developers and First Nations.

However, in BCSEA's view, more information is needed on IPP contract renewals and changes to the Standing Offer Program (SOP) than is presented in the 2013 IRP. BC Hydro's discussion of these resources[10] focuses on short-term reductions in resource acquisitions in response to a short-term surplus of resources. The IRP should also address the longer-term benefits of these resources, and BC Hydro's contingency plans should also reflect the ramping up of acquisitions of these resources where warranted by higher-than-forecast loads.

5. Potential liquefied natural gas (LNG) requirements

BC Hydro's contingent placeholder of 3,000 GWh/y for possible LNG export loads for planning purposes is not unreasonable, given BC Hydro's assumption that the electrical demand would be almost entirely for ancillary load, rather than for liquefaction. However, scant information is provided in the IRP on whether and how BC's legislated GHG reduction targets might force LNG projects to seek non-GHG-emitting forms of power in preference to natural gas or other fossil fuels. The IRP should include a contingency scenario in which LNG liquefaction loads also are met with electricity, as opposed to natural gas.

Regarding reinforcement of the 500 kV transmission line between Prince George and Terrace, BCSEA believes there is a good case to be made for this project, with or without LNG loads. However, a Utilities Commission review is needed to test the assumptions and analysis.

6. Contingency plans

BCSEA believes that BC Hydro relies too much in its contingency plans on gas-fired capacity resources. As discussed above under "Site C and capacity resources," BC Hydro should do more to advance capacity conservation options, and it should consider advancing the Revelstoke 6 and GM Shrum capacity projects to their earliest in-service dates under all scenarios.

BCSEA also believes that BC Hydro's contingency planning should include ramping up energy conservation measures in high-load contingencies. BCSEA is not convinced by BC Hydro's apparent assumption that high load contingency would necessarily be coupled with a reduced ability to deliver energy conservation savings.

Other comments:

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[9] http://www.climatechange2013.org/images/uploads/WGIAR5-SPM_Approved27Sep2013.pdf
[10] 2013 IRP, Chapter 4, section 4.2.5.1

7. The IRP should address significant "game changing" possibilities

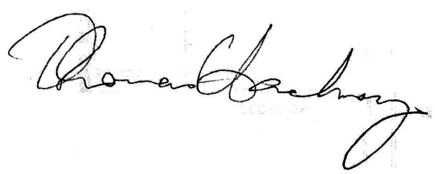
BCSEA appreciates BC Hydro's assessment of the electrification potential in BC.[11] This is a helpful addition to the plan. This section of the IRP could be re-named and cited in the IRP's introduction to reflect that it addresses BC Hydro's potential contribution to BC's Climate Action Plan and legislated GHG reduction targets.

BC Hydro should also consider an assessment of the potential contributions of solar photovoltaic (PV) power, in the case where falling equipment prices made it attractive for individuals to install PV arrays on their homes.

BCSEA respectfully encourages the government to initiate a strong, detailed action plan for BC to meet its legislated GHG reduction targets, as a necessary complement to BC Hydro's IRP.

Conclusion

The above is respectfully submitted.



Thomas Hackney, Policy Director

[11] 2013 IRP, section 6.7, pages 6-84 to 6-92

WRITTEN SUBMISSION FROM:

CLEAN ENERGY ASSOCIATION OF BRITISH COLUMBIA

Clean Energy BC

Friday, October 18th 2013

Mr. Charles Reid
President and CEO
British Columbia Hydro and Power Authority
18th Floor – 333 Dunsmuir Street
Vancouver, BC

And Via e-mail: integrated.resource.planning@bchydro.com

Dear Charles:

Re: Commentary on BC Hydro Draft 2013 Integrated Resource Plan

Clean Energy BC offers the following comments on BC Hydro's Draft 2013 Integrated Resource Plan (the IRP) released in August. We welcome the opportunity to share with you the comments and concerns of our industry.

Both BC Hydro and the clean energy sector each find ourselves in a difficult time. We are both challenged by markets, policy directions and a larger environment with a fair amount of uncertainty. The consequences for getting it wrong are costly and the risks high. We both know that in the face of high uncertainty and high risk, organization, system and strategic planners look to build in options, choices, and contingencies.

With respect, we believe that BC Hydro's draft IRP as it has evolved over several years and iterations does not represent a robust energy plan for British Columbia. The province's situation and circumstance has changed dramatically on a number of fronts. While the domestic resource economy remains in low growth, the key sectors represented in the Jobs Plan are set for explosive growth – export LNG and upstream shale gas developments. The expanded role of First Nations in the clean energy sector and the changing nature of social license for all natural resource development activities require all of us to revise our plans.

Whether intended or not, a by-product of the IRP as drafted by BC Hydro, if approved by the government will lead to a shutdown of the private sector clean energy industry in British Columbia for two decades.

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New development capital will not be invested and a whole generation of development professionals will be deployed elsewhere. The $4 billion in capex represented by the 21 clean energy projects just completed, currently commissioning or now being built and the 3,000 direct jobs (700 Aboriginal) and the supply chain represented in urban and hinterland BC will disappear after 2016. It will go quiet for the clean energy sector as even BC Hydro's Standing Offer Program (SOP) has now effectively been curtailed.

What has led BC Hydro to design its draft plan for this outcome? The new government's mandate letters to cabinet ministers hold them accountable to see clean energy grow and develop further in BC. Local governments and First Nations have all expressed support through formal resolutions this fall for expansion of the clean energy sector. BC Hydro's own poll undertaken in 2012 and repeated again in 2013 corroborates this support. As a production partner we are somewhat mystified by the draft IRP.

Admittedly, the Clean Energy sector has its own perspective. The same is true of BC Hydro – it is represented in your draft IRP – how you assess load and supply options such as DSM and Site C.

There remain serious questions around the effectiveness of DSM. There is really no way to empirically show when someone has decided not to use electricity, and historical use patterns do not appear to be changing. The billions being invested in DSM programs require a sober review. Don't get us wrong, there is broad support for DSM amongst industry and the public in general, including the clean energy sector, however, it is a question of cost effectiveness on the margin…of degree.

The draft IRP calls for no new generation for a decade and then Site C. There are very real questions around the cost-effectiveness of site C…its low cost of capital , its long amortization period , the fact that it's cost is not adjusted to the lower mainland, the fact that its costs are not locked in as is the case for clean energy projects. As important, the very uncertainty of power demand implicit in the draft IRP questions an $8 billion investment when the same requirements could be met incrementally as demand is proving out using cost-effective, proven and demonstrated thermal and renewable supply options. It's a big gamble at the very least, and since it won't be a "Heritage Asset" for a century, is it really worth it.

BC Hydro has conceded that it is not providing power to the burgeoning LNG industry. This is inconsistent with the environmental/economic mix that the public, industry and First Nations

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support, inconsistent with the Premier's "cleanest LNG" public position and inconsistent with our understanding of what the LNG industry wants.

Industry in general, not just the clean energy sector, sees ways that free enterprise and competition can contribute to a secure, economic energy future. Sometimes these are relatively large projects; sometimes they come one or two megawatts at a time. Regardless, shutting free enterprise out of power markets for decades is a dire conclusion.

It flies in the face of a need for system diversity and resilience; it flies in the face of good planning.

Clean Energy BC will recommend to the Minister of Energy and Mines that he seek an external third party to review BC Hydro's draft IRP and to make recommendations for its revision.

As always, I remain available to discuss this submission with you and your colleagues.

Sincerely

Paul Kariya
Executive Director

Cc: Honorable Bill Bennett, Minister of Energy and Mines

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Clean Energy Association of British Columbia
A Submission on BC Hydro's Draft
Integrated Resource Plan
October 18th 2013

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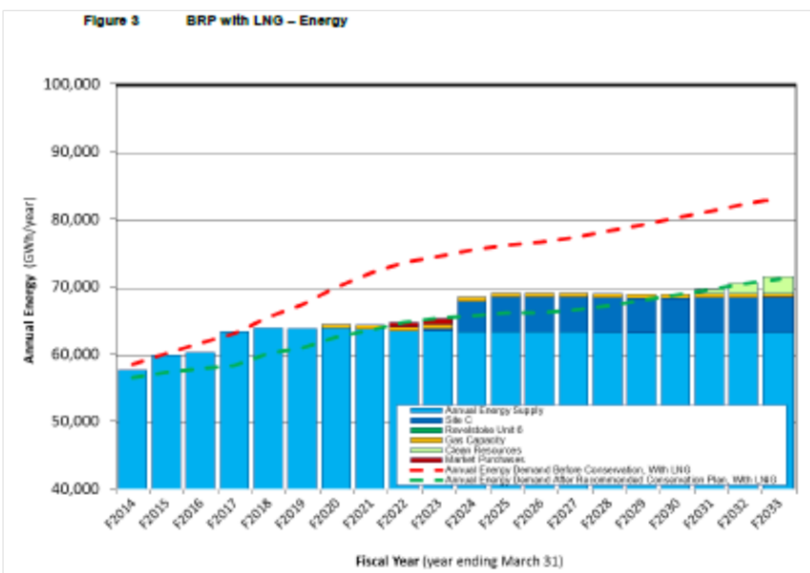
Commentary on BC Hydro Draft 2013 Integrated Resource Plan

Critical choices and assumptions

Our industry's fundamental concerns with this draft of the IRP stem more from the apparent omissions than from the inclusions. Our fear is that these omissions are extremely significant for our industry, as well as for all future generations of British Columbians, and yet they may be founded upon a number of critical assumptions that remain unstated in the IRP analysis.

1. **The choice to rely on Demand Side Management to save over 70% of domestic load growth.**

The Chart below depicts the Load Resource Balance (LRB) for the IRP's Base Resource Plan (from Appendix 8A Page 12). In this chart, the dotted red line climbs by about 17,000 GWh over the next decade, including a provision of 3,000 GWh to serve some ancillary load for LNG in F2021 and an increase in domestic load of about 14,000 GWh/yr.



The chart shows that the single largest program proposed to meet this growing load is Demand Side Management (DSM), indicated by the difference between the dotted red and the dotted green lines.

Since the 3,000 GWh of LNG ancillary load will be designed and built with modern efficiency standards and therefore unlikely to afford much opportunity for further efficiency savings, BC Hydro is proposing that it can reduce the domestic load by over 10,000 GWh/yr by F2024

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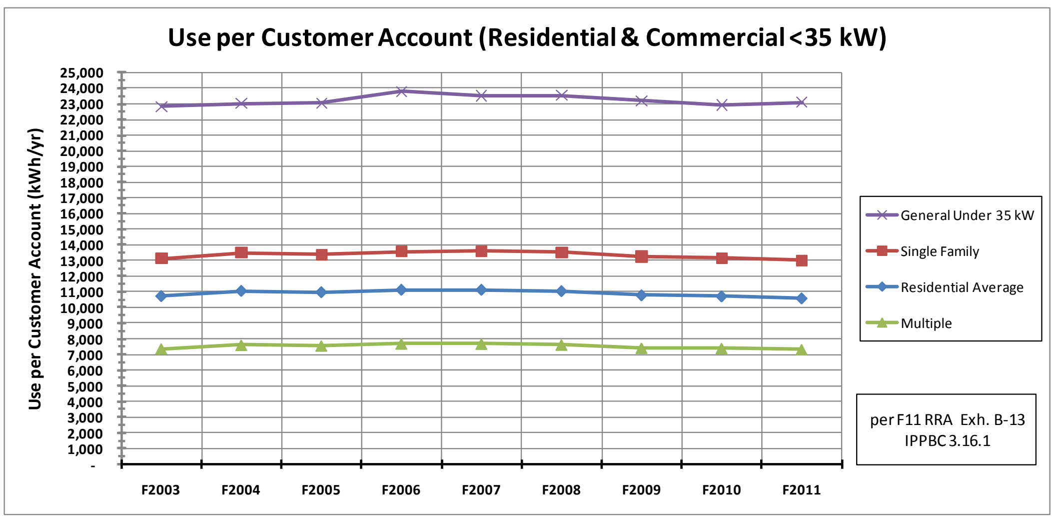
through the spending of $1.2 billion on its DSM programs. This means that DSM measures are being relied on to produce over 10,000 GWh of annual savings relative to the forecast domestic load growth of 14,000 GWh by 2024 -- a 72% reduction.

However, it is not the new growth of 14,000 GWh growth that will provide that saving, because that incremental growth will also be designed and built with modern efficiency standards and therefore unlikely to afford much opportunity for further savings. Therefore, DSM is actually being expected to produce another 10,000 GWh savings from the existing customer base -- and this comes after 30 years of DSM efforts have already harvested most of the "low hanging fruit".

There is a very high risk that this level of saving cannot be achieved.

1.1 Placing such a high reliance on DSM is an extremely risky gamble partly because the record over recent years contradicts this level of savings.

Over the period from 2003 to 2011, BC Hydro expended over $1.1 billion on its DSM measures, and DSM participants were estimated to have spent another $1.4 billion, and yet the chart below shows that the electrical consumption per customer remained virtually flat. (Chart derived from response to IPPBC IR 3.16.1 in Exhibit B-13 of the F2011 Revenue Requirements Application.)



This does not necessarily prove that the DSM measures were not effective when evaluated on their own terms, but what the chart does indicate is that as fast as the DSM measures may have reduced consumption, the customers found so many new applications that their electricity usage remained unchanged.

Over an 8 year period, a relatively high level of DSM expenditures only managed to keep the increase in customer demand down to the level of population growth. Yet the IRP is projecting a much greater rate of savings over the next 10 years.

Now it is true that over the coming decade, BC Hydro's proposed rate increases will have a dampening effect on demand. However, Hydro states that the effect of rate impacts on consumer demand has already been removed from the dotted red line in the first chart.

On that basis, it is extremely risky to rely on DSM measures to achieve the ambitious targets set for them in the IRP - especially since BC Hydro has already been active in Demand Side Management for the past 30 years, and has already exploited all of the most promising and least cost programs.

1.2 The bundling of different types of DSM measures masks the true cost of DSM Programs.

In fact, the spectrum of DSM includes a wide range of measures, some of which are extremely cheap (at least from the utility's perspective), and some of which are actually much more costly to ratepayers than the alternative of providing increased renewable supply.

Typically included in the DSM spectrum are three quite different classes of measures:

- **Electricity Rates -** Increases in the price of electricity, relative to the cost of other goods and services, will naturally cause customers to consume less, especially over a longer term, when they have time to react and adjust their behaviour, and especially when those price increases are dramatic and alarming relative to their disposable income.
- **Codes and Standards** - When government passes laws changing the building codes or equipment performance standards, that imposes a change in consumption that costs the utility very little. Of course it may cost the customers a great deal to conform to the new standards, but that is easily overlooked in the utility's accounting.
- **DSM Programs -** This is typically where the utility will place most of its dollars and human effort, promoting, subsidizing, and "incentivizing" customers to undertake various conservation or efficiency measures. Utilities will typically have a half dozen programs aimed at each of the residential, commercial, or industrial customer classes.

Of these 3 classes of DSM measures, the Programs generally take the majority of the costs, but they do not necessarily produce the majority of the benefits. In fact, in the F2011 RRA proceeding, CEBC observed that DSM Programs took up over 70% of the costs (especially

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when overhead costs are also allocated), but produced less than 30% of the expected energy savings.

Thus, for the amount of energy savings they achieve, Programs are very expensive, when compared to the savings from Rate Increases, and changes to Codes and Standards. However, this discrepancy of cost-effectiveness is never revealed as long as the 3 classes of measures are "bundled" up together and, as a consequence, Power Smart Programs are cast in a better light than warranted.

As long as this "bundling" is allowed, the high relative cost of Program spending is given a free ride on the coattails of the low cost/high impact Rate Increases and Codes & Standards.

1.3 Energy savings do not necessarily result in rate reductions.

In fact, quite the opposite is often true. For instance, if BC Hydro spends $1.2 billion on its DSM programs, and they manage to reduce the energy load by 5%, it's true that the individuals who participated in those programs may have reduced their bills. However, in so doing they will have reduced the amount of BC Hydro's fixed costs they will be contributing (and the vast majority of BC Hydro's costs are fixed), so now the same amount of fixed costs must be spread over fewer MWhs -- increasing the rates for everyone -- plus the amortization of the $1.2 billion must now be added to those annual fixed costs and paid for by the reduced MWhs.

The corollary to this is that successful DSM programs can still lead to rate increases, and unsuccessful ones will lead to even higher rate increases -- because we will have spent the $1.2 billion and then we will still have to acquire the additional energy as well, effectively a double payment.

DSM suffers from the same handicap as the Site C mega-project, namely that it requires a large up-front investment for an uncertain future return. If the anticipated savings fail to be achieved then the cost will be doubled, because the up-front payments will have already been made, but the replacement energy will then have to be acquired as well. At least in the case of independent supply-side projects, the energy is only paid for when it is delivered.

Therefore, contrary to popular myth, demand side measures do not necessarily result in rate reductions. For example, the 2008 LTAP filing estimated that 11 out of 18 residential, commercial, and industrial Power Smart programs caused rates to rise.[1]

[1] Table 9, appendix K, Sub-Appendix C, p. 117 of 2008 LTAP application

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2. The choice to rely on a single high-risk project at Site C.

The Site C dam and generating station is to be a single massive public sector mega-project. It is the second largest resource BC Hydro's IRP relies on to close the domestic Load Resource Gap over the next 10 years. It is budgeted at $7.9 billion but these cost projections are by no means certain, being 10 years into the future, for a project whose timing will coincide with several other large projects (pipelines and LNG plants, for instance). There will be significant labour and cost challenges associated with all these major projects being built simultaneously.

The Site C project is opposed by many First Nations and community groups in the region. Without its purpose being to support regional economic development, in particular regional development of renewable energy, its social mandate hangs on a thread, and it could easily be delayed many years, or even cancelled, by court action or community opposition.

Its economic advantage also hangs by a very thin margin. BC Hydro's own present value analysis shows that if it is subject to only a 10% capital cost increase it will be inferior to a portfolio of clean plus thermal generation. A 10% capital cost increase is trivial for a project that far in the future. The NW Transmission Line cost has increased by over 80% from its initial estimate of $400 million only 5 years ago. This is not an isolated incident, the history of Crown Corporations meeting capital budgets is dismal (e.g. Darlington, Point Lepreau, WPSS all exceeded budget by more than a factor of two) The chances are very great that Site C will cost much in excess of its $8 billion estimate, and all of that additional cost will flow directly to the ratepayers.

This means that the long term impact on ratepayers will quite likely exceed that of the renewable plus thermal alternative.

It has also taken a degree of alteration of the discount rates to award even this narrow 10% margin to Site C. Even after penalizing private sector development by 40% on its relative weighted average cost of capital (WACC), Site C manages only a slim 10% advantage.

BC Hydro does benefit from the implicit equity being supplied by the provincial taxpayers, and the backstopping of that taxpayer equity is what gives BC Hydro its low cost of capital. Yet, when we consider the risks that Site C will be subject to, it is arguable that those taxpayers should be asking for at least as much return as private sector developers.

The addition of a minimum of $8 billion of capital to the provinces debt burden together with taking on development risk may possibly result in a rating downgrade together with a tangible increase in the cost of debt servicing for the province.

Site C constitutes a huge single investment to be betting on a very risky and costly outcome, with no "off-ramp" available for mid-course correction once the path is taken.

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3. The choice to omit the electrification of LNG

BC Hydro has identified a dozen LNG facilities being proposed for the north coast. Considering just 4 proposals, all from serious world-scale companies, they intend to export 34 million tonnes per year (mtpa) from Kitimat (Chevron and Shell), and another 41 mtpa from Prince Rupert (BG and Petronas).

That 75 mtpa of LNG exports will require over 30,000 GWh per year for the downstream energy load alone,[2] with probably an additional 20,000 GWh per year for the upstream energy loads (for gas drilling, extraction and processing and pipelines from northeast BC). Yet BC Hydro's draft IRP provides for only 3,000 GWh to serve some ancillary loads in the liquefaction plants (and that only as a potential variation on its Base Resource Plan).

That 75 million tonnes of LNG exports per year will occur well within BC Hydro's planning horizon, yet only 6% of the 50,000 GWh annual energy requirement appears in the IRP.

Regarding the energy requirements for LNG, BC Hydro's draft IRP states (in sub-Appendix 3.3 - LNG Load Outlook, of Appendix 2A, Electric Load Forecast,):

> *"The 2012 Reference Load Forecast presented in this document does not include any specific LNG demand beyond very small allocations associated with on-site construction."*

BC Hydro justifies adopting this "No-LNG" forecast by quoting from the proponents project descriptions as submitted with their environmental assessment applications (see footnote 9 on Page 1-4 of the IRP):

> *"Each LNG liquefaction train will utilize natural gas-fired direct drive for the major refrigeration compressors to produce LNG", and*
>
> *"The facility will be designed to be self-sufficient for all power needs by onsite combustion of a proportion of the natural gas supply to the Facility in gas turbines."*

There is a very big difference between designing a facility to be self sufficient and running it that way. The gas technologies employed are easily dispatchable, at least those intended to meet the 1/3rd of load not associated with the direct drives. The LNG industry itself has indicated a strong desire to dispatch these facilities in favour of renewable power yet no clear renewable option has been investigated and this IRP suggests that none ever will be.

[2] BC Hydro's May, 2012 Draft IRP, page 2-8, estimated the energy requirement for Shell's 24 mtpa plant at 10,000 GWh per year, plus another 2,000 GWh for pipeline compression and 800 GWh for transmission losses, with a total capacity requirement of 1,200 MW for the plant and 500 MW for the pipeline compression. Projecting this plant energy requirement onto the total 75 mtpa gives over 30,000 GWh of annual energy.

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It seems that, rather than recognizing that potential load and investigating the possible ways it might be served, the draft Plan simply assumes that this enormous amount of new energy will all be provided by the industry burning its own fossil fuels. The environmental consequences of this assumption could be significant, both locally and globally, yet these consequences are not recognized in the IRP analysis.

This exclusion of the major LNG loads employs a circular logic. BC Hydro takes the position that it does not need to include any load for LNG because the industry has chosen not to use electricity. However, the LNG industry may be taking that course because it has not been offered an alternative for the timely supply of cost effective and reliable electricity.

4. The benefits of flexibility and diversity in energy production are missing

This is essentially an unstated consequence of the 3 choices above. By omitting any load for the electrification of LNG, and by opting for the Site C mega-project, and the aggressive 72% DSM target, the draft IRP effectively eliminates any capability for acquiring a diversity of energy production, both geographically and by different clean energy fuel types.

Along with that diversity, it eliminates the flexibility to change the mix of generation alternatives as conditions change in the future. This optionality will be lost if the draft IRP, in its present form, is followed.

Preserving the optionality to move in different directions in the future has a great value that is being sacrificed by the choices struck in this draft IRP.

5. The benefits of First Nations and private sector involvement in renewable energy development are also missing

This is also an unstated consequence of the first 3 choices.

125 First Nations have been strong and enthusiastic partners in the development of energy projects in all regions of British Columbia. This IRP will eliminate all significant opportunities for their further participation, since there are no new calls for energy anticipated until 2031, and since the Standing Offer Program target energy has been effectively reduced to less than the output of a single 15 MW run or river hydro plant.

Private sector developers, seeing no future prospects in British Columbia, will look elsewhere as will the technical and commercial supply chains that support the sector. The capabilities of an industry will be lost, and not easily or quickly recovered - a fact which strains the credibility of the Contingency Resource Plan, since it relies on an industry which will be extinguished by the Base Resource Plan.

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6. Potential damage to the environment could be significant, both locally and globally

From a global perspective, the GHG emissions of this IRP could be significant.

If the energy requirements of the LNG industry are not served by non-emitting renewable electricity, but instead are left to be served by the industry burning its own fossil fuels in its traditional manner, then the consequences for BC's GHG emissions could dwarf all of BC's present emissions from all industrial, commercial, and residential sources.

Allowing all of the 50,000 GWh of energy needed to produce 75 million tonnes per year of LNG exports (including both upstream and downstream energy), to be provided by the burning of fossil fuels will result in new BC-based GHG emissions of up to 75 million tonnes per year of new CO2.[3] BC LNG would be far from being the "cleanest" LNG in the world markets.

To put these proposed GHG emissions in context, BC's total emissions in 2007 were only 66 million tonnes, and we are pledged to reduce this to 45 million tonnes by 2020 (in fact it is the law). This is potentially a risky proposition for the future of the LNG industry in BC, because to date the government has been promising that BC's LNG would be the "cleanest in the world" and yet these emission levels would challenge that promise. The social license for this industry could be in serious jeopardy.

From a local perspective, the capacity of the local air sheds to absorb additional emissions will likely be exceeded, thereby endangering the health of First Nations and community residents.

LNG developments could be stalled because of a lack of planning for electrification.

Recommendations

In view of the many undesirable consequences identified in the draft IRP, particularly the unacknowledged consequences for the loss of diversity of supply of clean energy, impact upon First Nations and local communities, impact upon long term rates and concern for the environment, CEBC respectfully suggests that the draft IRP should be revised from its present form.

[3] When both the downstream and the upstream CO2 emissions are considered, the recent study by Tides Canada (available at http://cleanenergycanada.org/works/cleanest-lng-in-world/) calculated that each tonne of LNG exported will result in approximately 1 tonne of CO2 equivalent emissions within the province (depending on the level of formation gas vented). Hence, 75 mtpa of LNG will result in 75 mtpa of CO2 emissions.

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1. Meet with Clean Energy BC representatives to more fully explore all the options and opportunities for finding solutions. We strongly believe that a new energy plan can be created that can keep the private sector and First Nations actively involved in developing the reliable clean energy needed to power dynamic growth in British Columbia, while minimizing the accumulation of public debt and the impact of future rate increases on existing ratepayers.

   Re-assess the energy needs of the LNG industry, both upstream and downstream. Consider revising the load forecast and draft IRP recognizing the necessity of finding ways and means to increase electrification of northern industrial development.

2. Support the Premier's vision and re-examine ways and means to support the LNG industry to achieve becoming the "cleanest in the world". The IRP should also assume that this will be done in a way that insulates BC Hydro's existing southern ratepayers from any adverse impacts associated with the new northern development.

3. Propose a blend of gas-fired generation and renewables that will make electrification feasible, reliable and cost-effective for the LNG industry as well as for existing ratepayers. Gas fired generation can be blended with locally situated renewables. In the longer term it can serve as a firming and backup resource for province wide renewables, as that generation and the necessary transmission become available.

4. Propose a blend of public, private and First Nations participation that will allow electrification to proceed in a timely and cost-effective manner. All parties need to be prepared to find a new partnership structure that involves the private sector, First Nations, and BC Hydro in order to expedite the progress of electrifying as much as possible of the new northern-based industrial development. This partnering structure can effectively share the risk and the financing burden, while also insulating BC Hydro's existing ratepayers from any associated rate impacts.

Respectfully submitted,
Clean Energy BC

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WRITTEN SUBMISSION FROM:

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

Commercial Energy Consumers (CEC) Association of BC

Comments on the BC Hydro Integrated Resource Plan of August 2013

October 18, 2013

1. Introduction

Consultation

The CEC is reviewing the BC Hydro Integrated Resource Plan (IRP) as a member of the Technical Advisory Committee (TAC) to BC Hydro. The TAC did not meet or hold any consultation sessions with BC Hydro during the development of this version of the IRP. Furthermore BC Hydro's consultation committee specifically dealing with DSM, the Energy Conservation and Efficiency committee of which the CEC is a member also did not meet throughout this period prior to the production of the IRP.

The CEC considers the concept of consulting about something as substantive and technical as the IRP in the course of a 1 day session to be a gross failure of process.

Fundamentally, the IRP has failed to deliver an optimal plan for BC.

Load Forecast

The IRP work starts from a forecast of the future demand for a period of 20 to 30 years. The table below summarizes the load forecast before the anticipated DSM savings.

Table 2-3 Sector Breakdown of Energy Mid Load Forecast (before DSM, without losses)

Energy Load (GWh/year)	F2017	F2023	F2028	F2033	Compound Growth Rate F2014-F2023 (%)	Compound Growth Rate F2014-F2033 (%)
Residential	19,761	22,291	24,409	26,471	2.0	1.9
Commercial	17,815	20,323	21,865	23,700	2.2	1.8
Industrial (without LNG)	19,016	21,207	20,836	21,273	2.5	1.2
New Westminster/FortisBC Contractual Sales	995	1,535	1,614	1,654	5.0	2.7
Domestic Sales (without LNG)	57,587	65,356	68,725	73,097	2.3	1.7
Expected LNG	0	3,000	3,000	3,000		
Domestic Sales (with Expected LNG)	57,587	68,356	71,725	76,097	2.8	1.9

Incorporated into this forecast is an anticipated set of rate increases for electricity, which will dampen the future demand for electricity. This is disclosed in a footnote on Page 2-4.

> 1 The BCUC in its 2006 IEP Decision, page 154, ordered that BC Hydro include a forecast of BC Hydro's rates in its load forecasts. BC Hydro has included rate forecasts in its load forecasts since 2008. Note that actual rate increases are determined through BC Hydro's Revenue Requirements Application, and may differ from forecast assumptions.

Unfortunately the load forecasts are provided with the electricity rates assumptions embedded into the forecasts and the assumptions are not clearly provided. Consequently it becomes difficult to both understand and critique the load forecasts.

As past load forecasts have proven to be overstated, anticipating more load than has materialized, there is a need to remain skeptical with regard to the load forecasting. To be fair the impacts of the Great Recession have been very significant and continue to show a depressed demand. This should be a warning to us all that the demographic trends associated with the aging baby boom generation can be expected to deliver future surprises with respect to demand forecasting. It is a certainty that we have not seen our last financial crisis in the world and that we can therefore expect future impacts associated with the next one.

BC Hydro's electricity rate forecasts are an absolutely critical piece of information because they are anticipated to be growing significantly faster than the rate of inflation. This will have the prospect of creating conditions where the BC Hydro rates cross over the cost structures for competing alternatives for supply, particularly for industry. For many decades the improving cost-effectiveness of hydroelectric power, with its increasing economies of scale, has been the dominant understanding for electric energy in BC. With the anticipated BC Hydro rate increases the future impacts on demand may not be associated with a linear concept for the elasticity impacts. At some point, with rate increase well above the rate of inflation, it will become much more likely that the changes with become structural and the demand decreases become step reductions.

The IRP does not do sufficient planning for this possibility. Criteria for managing this risk would be a useful part of improving the IRP and a starting point would be better disclosure of the rate impacts being used in the load forecasting.

Already we have in the IRP anticipation of significant industrial loads (the LNG loads), which are not expected to be using electrical energy from BC Hydro in any substantial proportion to their total energy demand. Although BC Hydro is anticipating serving some of these loads it is more likely that the industry will balk at the future price of energy coming from BC Hydro. Will the rest of BC's energy intensive industries be far behind if this evolves?

Long-run Marginal Cost of New Supply

BC Hydro has reduced its long-run marginal cost (LRMC) from $135/MWh down to $100/MWh and is allowing for provision for this to potentially reduce to $85/MWh.

The LRMC outlook is as follows:

Energy: $85/MWh-$100/MWh F2017 to F2030.

Capacity: $50-$55/kW-year F2017 to F2030.

The existence of surpluses in the BC Hydro system adds to the LRMC for planning purposes.

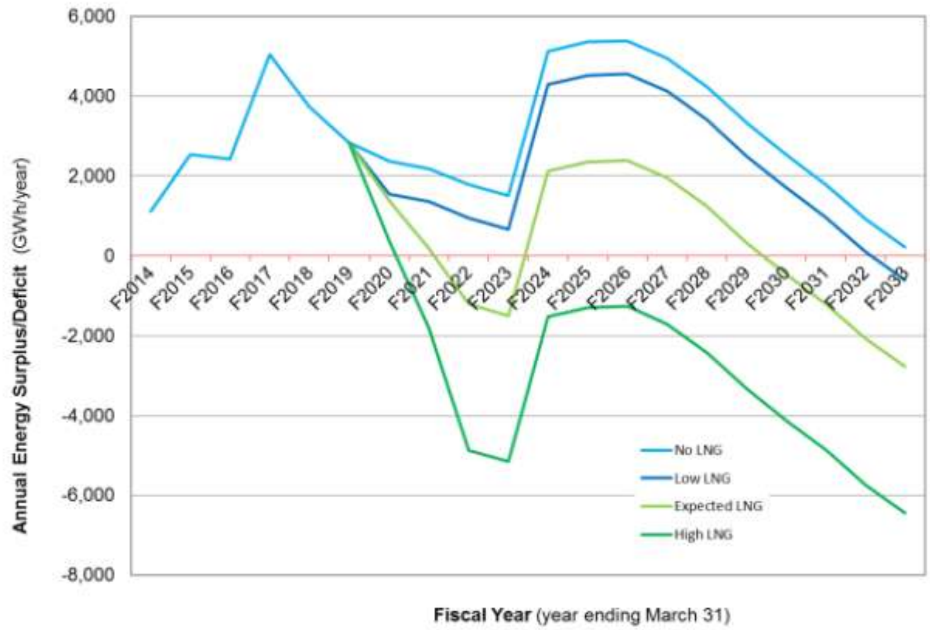
Table 4-18 Energy Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	5,041	3,725	2,828	1,366	179	-1,216	-1,886	- 3,864	-7,886
Surplus/Deficit with Incremental Resources without Expected LNG	5,041	3,725	2,828	2,366	2,179	1,784	1,114	-864	-4,886

Table 4-19 Capacity Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	332	204	77	-100	-244	-431	-576	-1,095	-1,993
Surplus/Deficit without Incremental Resources and Expected LNG	332	204	77	21	-4	-71	-216	-735	-1,632

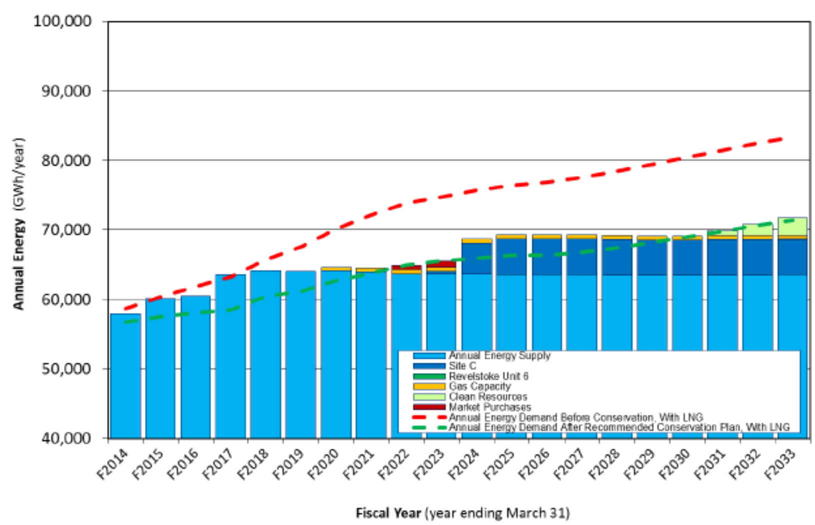
Figure 6-10 System Energy Surplus/Deficit after BRP Implementation under Different LNG Load Scenarios



The impact of surpluses will be approximately $10 MWh on the cost of power so they are quite a significant element of the LRMC in reality.

The future acquisition of new supply resources not only includes the Site C project in the Base Resource Plan (BRP) but also includes future new clean energy resources. The impact of these should also

Figure 8-5 Energy Load/Resource Balance: LNG BRP



factor into the determination of the LRMC because this future power supply also needs to be avoided for as long as possible.

The reduced LRMC may not capture real cost of future supply adequately. This LRMC also does not account for the risks inherent in the levelized cost numbers used to generate the LRMC, yet it is used as a base for comparison against the uncertainty adjusted numbers for DSM.

The CEC recommends that BC Hydro provide a wider range for understanding the real LRMC as it will impact the rates of BC Hydro customers.

2. Conserving First

The BC Hydro recommendations captured under the title of conserve first are summarized in Section 8 of the IRP as follows:

DSM (Conservation)	1. Moderate current spending and maintain long-term target	Target expenditures of $445 million on conservation and efficiency measures during the fiscal years 2014 to 2016. Prepare to increase spending to achieve 7,800 gigawatt-hours per year in energy savings, and 1,400 MW in capacity savings, by F2021.
	2. Pursue DSM capacity conservation	Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term.
	3. Explore more codes and standards	Explore additional opportunities to leverage more codes and standards to achieve conservation savings at a lower cost and to gain knowledge and confidence about their potential to address future or unexpected load growth.

DSM Trimming

A fundamental success BC Hydro has achieved in its DSM planning is to continue to increase the cost-effectiveness of the DSM options. A number of the items being trimmed from the DSM plan, particularly those with short term savings would be less cost effective and therefore the overall portfolio will have increased cost effectiveness.

In developing these reduced expenditures and maintaining the ability to ramp up, BC Hydro employed the following principles: 1) eliminate projects or activities that have a short energy savings persistence and thus only contribute to the near-term surplus period; 2) consider 'lost opportunities' by (a) continuing to offer incentives for energy savings opportunities that will not be available in the future (e.g., one time opportunities for incremental improvement to building envelope upgrades or new construction) and (b) defer incentives for energy savings opportunities that are not needed now but will have a predictable uptake regardless of when they are offered; 3) maintain program activities to retain a level of customer and trades engagement and relationships so that DSM programs can be ramped up to long-term savings targets as needed; 4) consider cost-effectiveness of DSM programs from both the UC and TRC perspectives; and 5) consider broad opportunities for customers to participate.

DSM Option Choice

One fundamental failure the BC Hydro IRP is its failure to directly address the benefits of delaying the next acquisition of additional supply resources. The DSM plan included in the IRP has been reduced from the plan level BC Hydro recommended in its last IRP submission in which it recommended pursuing its Option 3 level.

Cumulative Mid Savings from F2008 (GWh) at the Customer Meter	F2021 (GWh/year)
2008 LTAP Evidentiary Update (EU)	9,032
2012 IRP Option 2	9,435
2012 IRP Option 3	10,132
2013 IRP – Option 2 / DSM Target	9,032

BC Hydro has essentially retreated to its 2008 LTAP level for DSM. There is no doubt that there is more cost effective DSM to be delivered and that it could be used to beneficially defer the acquisition of new resources.

Cost-effective DSM

1 **Table 8-7 DSM Programs TRC and Savings**

DSM Programs (sorted by TRC net of capacity benefits)	*TRC net of capacity benefits ($/MWh)*	*Forecast Savings in F2021 (GWh/yr)*	*Cumulaltive Savings (GWh)*	*% of Total Cumulative Savings*
Behaviour	6	135	135	5%
Load Displacement - Industrial	27	432	567	20%
Refrigerator Buy-back	35	66	633	22%
Power Smart Partner - Transmission	36	1,021	1,653	58%
Load Displacement - Res	42	0	1,653	58%
Residential Rebate	45	53	1,706	60%
Power Smart Partner - Distribution	51	265	1,971	70%
Power Smart Partner - Com	54	450	2,421	85%
Product Incentive	55	173	2,594	92%
Lead by Example	76	28	2,622	93%
Renovation Rebate	77	56	2,678	94%
Load Displacement - Com	78	4	2,682	95%
New Construction	83	123	2,805	99%
Low Income	111	20	2,825	100%
New Home	113	8	2,834	100%

As the above table shows the DSM programs are virtually all cost effective against the long run marginal cost and therefore the DSM efforts can and should continue. Deferral of the acquisition of new supply will be cost effective for the total resource cost investment and will be very cost effective for the utility to be implementing. Given that much of the DSM program effort is related to leading the codes and standards initiatives the cost effectiveness of the combined efforts is applicable. Combining the programs, codes and standards and the rate structure efforts as a package aimed at transforming the energy use markets will lower the overall cost per unit and demonstrate a huge cost-effectiveness advantage for DSM over any other approach. Already it is evident that the trimming of the DSM initiatives has cut into cost-effective options and resulted in a suboptimal choice of DSM Option for the IRP

The CEC recommends to BC Hydro and to the government that it view the DSM initiatives as a package and avoid assessing programs specifically and individually based on the LRMC, as this will lead to a suboptimal IRP.

DSM Dynamic Delivery Capability

DSM has a dynamic delivery capability in that it is able to change out initiatives that are not working well and replace them with better designed initiatives. The specific DSM initiatives can be and are improved as they progress so that they become more cost-effective with the learning. Much of the technology enabling the DSM initiatives is constantly undergoing improvement, which further leads to increased ability to deliver results. This dynamic nature of the DSM initiatives is not adequately recognized in the IRP.

The IRP takes a rather static approach to the DSM plan and furthermore assigns significant uncertainty discounts to potential new DSM activity. The history of the DSM initiatives from BC Hydro is that they have continually improved and have consistently delivered energy savings. The ability to generate savings has been directly tied to the degree of investment to obtain the savings. There is no sound evidentiary basis for assigning uncertainty discounts to the DSM potential available. Furthermore to the extent uncertainty may exist because tracking and evaluation may lag the performance it is possible to invest in more incremental DSM initiatives to provide assurance that the expected amounts of savings will be achieved.

The CEC recommends to BC Hydro and to the government that the model for DSM be developed to acknowledge the dynamic nature of DSM and its ability to be the most reliable delivery of energy BC Hydro has.

DSM Limits on Future Initiatives

The DSM plans included in the IRP make the assumption that codes & standards work over the 20 year to 30 year timeframe will not continue at a pace to secure the optimal long term use efficiencies. The same occurs with respect to the implementation of rates initiatives and other potential market parameters, which would encourage conservation and efficiency. The existing conservation rate structures are all that is assumed for the period. The tapering out of benefits in the later years of the plan is a serious flaw.

The DSM plan is based on a 2007 Conservation Potential Review (CRP), which itself was based on 2005 data inputs. This information is long out of date and provides a poor foundation for the DSM planning at this point in time. The CRP was at the time confined largely to existing commercial technology with a limited look forward. This was a very conservative assumption. The reality is that the energy saving technology field has continued to grow and burgeon with new opportunities and improvements on older versions of the technology. The DSM in the IRP does not recognize the technological development path nature of DSM over a 20 year period and therefore can result in over commitment to supply side resources.

DSM conservation and efficiency will undoubtedly continue to develop and improve over the entire planning period. The failure to incorporate this into the model options for DSM results in a suboptimal plan for conservation and efficiency in the IRP.

The CEC recommends to BC Hydro and to government that before there is a significant commitment to new supply side resources a new CRP be undertaken and that the modeling for DSM have the limitations on the most cost-effective components of DSM replaced with a presumption of long term conservation and efficiency implementation through codes and standards and market mechanisms such as rate structures and terms and conditions.

DSM Options 4 & 5 Discounting

The BC Hydro process used to generate and discount the DSM options 4 and 5 was significantly flawed. There are a number of highly beneficial options for obtaining additional DSM savings and the failure to isolate these and include them in planning for cost-effective DSM leads to a suboptimal IRP.

Transformation to Market Driven DSM Activity as a Next Step

The next most beneficial step in the development of DSM in BC will be to transform significant DSM into the private sector market place as a market driven activity, with the appropriate supporting mechanisms.

The CEC recommends that the government and BC Hydro develop and implement this transformation in steps and stages over the next few years.

DSM Contribution to the Economy

BC Hydro's DSM plans have very distinct and beneficial consequences for the BC economy. The total resource cost tests show a benefit of around 3 times the cost. This translates into very significant contributions to the overall productivity of the economy and to the specific benefit of particular customers making the savings.

Table 8-6 DSM Implementation Plan – UC and TRC Benefit-Cost Ratios at Alternate LRMCs[3]

	LRMC at $100/MWh		LRMC at $85/MWh	
	UC Test	TRC Test	UC Test	TRC Test
Codes and Standards	**117.1**	**5.5**	**99.5**	**4.7**
Rate Structures	**16.4**	**10.0**	**14.0**	**8.5**
DSM Programs				
Residential Sector				
Behaviour	3.5	4.8	3.0	4.1
Refrigerator Buy-Back	1.5	2.1	1.2	1.7
Low Income	0.9	1.0	0.7	0.9
New Home	1.3	0.7	1.1	0.6
Residential Rebate	1.8	1.8	1.6	1.5
Renovation Rebate	2.5	1.2	2.1	1.0
Load Displacement	6.5	2.4	5.5	2.0
Residential Sector Total	*2.4*	*2.0*	*2.1*	*1.7*
Commercial Sector				
Power Smart Partner	1.9	1.7	1.6	1.4
Product Incentive	2.2	1.6	1.9	1.4
New Construction	2.2	1.4	1.8	1.2
Lead by Example	1.1	1.1	1.0	1.0
Load Displacement	2.5	1.4	2.1	1.2
Commercial Sector Total	*2.0*	*1.6*	*1.7*	*1.3*
Industrial Sector				
Power Smart Partner – Transmission	4.0	2.3	3.4	2.0
Power Smart Partner – Distribution	1.9	1.7	1.6	1.4
Load Displacement	3.2	2.9	2.7	2.5
Industrial Sector Total	*3.2*	*2.3*	*2.7*	*1.9*
Total Programs	**2.6**	**2.0**	**2.2**	**1.7**
Portfolio Total	**5.2**	**3.1**	**4.4**	**2.7**

In addition the actual work of implementing DSM is significant. BC Hydro has completed a study showing the conservation and efficiency industry supporting DSM will provide about 200,000 person years of employment over the planning period or over 6,000 person years of employment per year all generating additional value in the economy.

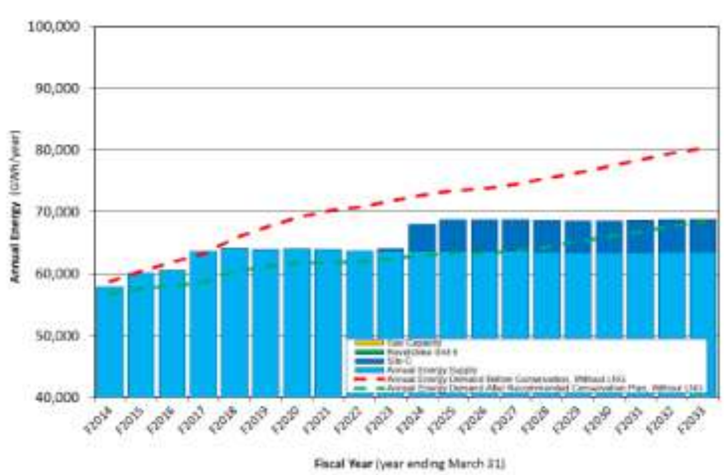
3. Powering Tomorrow

Supply-Side Resources	6. Continue to advance Site C	Build Site C to add 5,100 GWh/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in service date of F2024 (for all six generating units) subject to: environmental certification; fulfilling the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups; and Provincial Government approval to proceed with construction.
	7. Pursue bridging options for capacity	Fill the short-term gap in peak capacity with cost-effective market purchases first and power from the Columbia River Treaty second.
Transmission Resources	8. Advance reinforcement along existing GMS-WSN-KLY 500 kV transmission line	Advance reinforcement of the existing GM Shrum-Williston-Kelly Lake 500 kV transmission lines to be available by F2024.
	9. Reinforce South Peace transmission	Review alternatives for reinforcing the South Peace Regional Transmission Network to meet expected load.
Other	17. Fort Nelson area supply options	Investigate procurement options to serve future Fort Nelson load.

Load Resource Plan with Site C and without LNG loads

The IRP shows that for the existing load forecast the resource supply balance without the 3000 GWh/year of expected load from serving LNG ancillary facilities the BC Hydro surpluses with Site C as the supply source run for about 10 years. These are very costly and add significantly to the cost of the Site C project, because the energy must be sold into the electricity markets at prices well below the cost of energy.

Figure 8-3 Energy Load Resource Balance: BRP

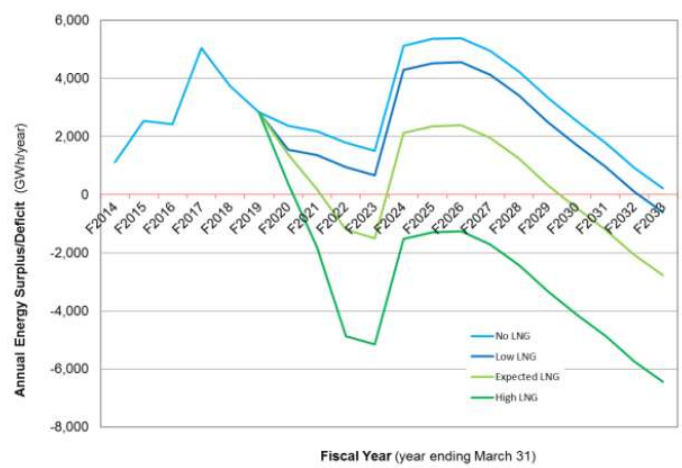


Site C – Large Increment Surplus Risk

The most significant primary feature for Site C is the large increment of supply brought on all at once. BC Hydro's IRP documents the need for Site C as showing an energy planning gap beginning in 2022 with LNG loads and in 2027 without the LNG loads.

- There is an energy gap beginning in F2027 and a capacity gap beginning in F2021 without Expected LNG load
- The corresponding energy and capacity gaps are F2022 and F2020 respectively with Expected LNG load

Figure 6-10 System Energy Surplus/Deficit after BRP Implementation under Different LNG Load Scenarios



Scheduling Site C to meet these loads commits a major capital expenditure long before the loads materialize. The existing CEA provisions for self-sufficiency appear to drive the planning to meet loads as they are forecast. The consequence is very large surplus energy amounts which then must be sold into the electricity markets at a loss. The same issue has occurred in the earlier 2012 to 2022 timeframe caused by purchase of too much Independent Power Producer (IPP) energy too early. The cost of these surpluses can be very significant costing in the order of billions of dollars.

The large increment risk is far more appropriately handled by meeting the load as it materializes with much lower investment cost facilities, such as Combined Cycle Gas Turbine (CCGT) plants. These plants run on low cost natural gas and run with efficiencies between 50% and approaching 60%. Once most of the load has materialized then it would become more viable to idle the CCGT plant until additional load builds.

The comparative costs for CCGT options are shown in the IRP resource options section.

Table 3-17 Summary of CCGT and Small Cogeneration Potential

Resource Option	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2013/MWh)
50 MW CCGT in Kelly Lake/Nicola	1	56	49	300	386	92
250 MW CCGT in Kelly Lake/Nicola	1	263	236	1,450	1,861	62
500 MW CCGT in Kelly Lake/Nicola	1	530	479	2,940	3,776	58
Small Cogeneration in Lower Mainland	1	10	10	80	80	74

Notes:

1. Representative project used to characterize the resource option.
2. UECs are based on natural gas price estimates from BC Hydro's 2013 Market Scenario 1, and do not include the cost of GHG offsets or the B.C. carbon tax.
3. Additional gas price scenarios and their likelihoods are provided in Chapter 5. The impact of these prices is addressed in the portfolio analysis described in Chapter 6.

With carbon tax the costs for CCGT energy would be about $10/MWh higher than these costs but still significantly below the Site C costs. At this time, from the assumptions not listed, we are uncertain whether this information is developed with the new cost of capital being used for Site C. The earlier resource options report used higher costs of capital. Also we do not know, from the assumptions, what the cost of gas was that is used for this data.

The reason BC Hydro does not explore such an important cost saving and risk reduction option is because they have worked to a constrained mandate of complying with the Clean Energy Act provisions of 93% clean energy without showing what other beneficial policy change options might provide.

Site C - Cost-effectiveness

BC Hydro makes a comparison of Site C with clean energy and with SCGTs and concludes that Site C is the most cost effective resource. This is driven by the 93% clean planning criteria and does not allow for important policy analysis, which results in a suboptimal IRP.

Table 6-5 Comparison of Adjusted UECs

	Site C	Clean Generation Block	Clean + Thermal Generation Block (Revelstoke Unit 6 and 6 SCGTs)	Clean + Thermal Generation Block (Revelstoke Unit 6, GMS and 4 SCGTs)
$/MWh	94[29]	153	128	130

Elsewhere in the discussion of Site C it is found to be cost effective against DSM options. The potential value of additional DSM in combination with clean renewable energy particularly firmed up by CCGT plants is not analyzed. Unfortunately again important policy analysis is overlooked leading to suboptimal conclusions.

- **DSM Option 3:** On its own, DSM Option 3 is not an alternative to Site C and needs to be combined with other clean or renewable alternatives or natural gas-fired generation. Site C is cost-effective against portfolios with DSM Option 3 and clean or renewable alternatives or natural gas-fired generation.

Comparisons of Site C to clean generation portfolios again suffer from the same constrained and truncated analysis, leading to suboptimal conclusions.

- **Viable clean or renewable alternatives:** Site C has a lower unit energy cost (**UEC**) at about $94/MWh[11] than clean or renewable resources which for a comparable Clean Generation block of 5,100 GWh/year of firm energy have a UEC of about $153/MWh. Site C is a cost-effective resource for both the F2024 and F2026 ISDs when compared on a present value basis to Clean Generation Portfolios in all but the small gap sensitivity and where Site C's capital cost is increased by 10 per cent.

Site C compared to natural gas fired generation suffers from use of SCGTs.

- **Natural gas-fired generation:** Site C's UEC of $94/MWh is lower than the UECs for the Clean +Thermal Generations blocks of $128/MWh (Revelstoke Unit 6 and six SCGTs) and $130/MWh (Revelstoke Unit 6, GMS Units 1-5 Capacity Increase and four SCGTs). Site C is also a cost-effective resource when compared on a present value basis to portfolios containing natural gas-fired resources within the *CEA* 93 per cent clean or renewable parameter. As set out above, Site C has a minor cost disadvantage if built by F2024 when compared to the Clean + Thermal Generation Portfolio in a low market price scenario, in the small gap sensitivity and in a scenario where Site C's capital cost is increased by 10 per cent.

The CEC has analyzed a portfolio of additional DSM, matched with available renewable energy and with CCGT capability to back up the supply as needed. This portfolio will be ½ the cost of Site C even when including the cost of carbon. The portfolio can be prepared to be delivered on a timely basis to more closely match the load growth as it materializes. This swing portfolio can be used continuously to avoid the costs of oversupply. Once the loads have materialized then it may be much more suitable to displace this use of natural gas with a project like Site C so that the Site C cost-effectiveness can be made more useful.

Site C – Market risks

The BC Hydro plan calls for 3000 GWh/year of load from LNG plants for their ancillary facilities. It is likely that this load will not be committed or contracted long term before a commitment to build a project like Site C is made. Consequently the BC Hydro plans will remain at risk relative to the materialization of such loads.

It is highly likely that the price for such energy will be well above and beyond the price of achieving supply for the LNG plants from their own resources. So there should be some caution with respect to whether or not they will commit to the connection to BC Hydro supply.

This purchase of energy by the LNG plants from renewable sources is the basis of the provincial claim that the LNG plants will be the cleanest in the world.

Further adding to this risk will be the potential for alternative renewable energy proposals to provide the LNG plants with more cost-effective supply than would come from BC Hydro. The CEC is aware of the development of such proposals and recommends that BC Hydro and the government take a much closer look at both the risks and opportunities.

Perhaps BC Hydro would be more aware of alternative options in its IRP process had it not been so constrained to the single metric policy criteria that fail to allow for the evaluation of appropriate trade-off decisions.

Site C- Risk of Cost Overrun

The IRP does run a sensitivity analysis for an overrun of 10% on the Site C costs and the analysis shows that the portfolios analyzed by BC Hydro are still cost-effective with Site C included.

BC Hydro did not run an analysis of what the cost overrun would have to be before the portfolios with Site C would become less cost effective than other portfolios they analyzed. However, in the analysis material there is enough data to make a rough interpolation and project that at about a 20% cost overrun the Site C project would not be cost-effective.

There are several reasons to be concerned about this risk. First, is that the CEC's consultant has previously analyzed all BC Hydro dam building projects based on early estimates before construction of the project and found that 100% of the projects had cost overruns and that the costs overruns ranged between 25% and 75% of the original estimates even though all of the estimating contained contingency estimates as well. Second, independent of this analysis there are examples of cost overruns on large BC Hydro projects so at a minimum there is a basis for anticipating some overruns. Third, major dam construction projects are more prone to overruns than many other types of projects BC Hydro undertakes.

Site C – Technology Risk

The Site C project is a major commitment of capital, which could not be in service until at least 10 years from now.

During this time the technology driving other competing energy options is moving very quickly and there is an emerging potential for technological obsolescence. BC Hydro has analyzed the solar energy technologies from the point of view of centralized utility supply and only looked at the PV technologies at a size of 5 MW.

> Solar Power (**CSP**) technologies. Both the photovoltaic and CSP technologies are commercially proven. Globally costs for solar technologies have declined dramatically. While this trend is expected to continue, costs are not expected to become competitive in Canadian jurisdictions over the next 10 years in the absence of price support. There are no known commercial solar power installations in British Columbia. However, several BC Hydro customers have installed solar panels.

> The solar resource option assessment focuses on utility-scale photovoltaic systems, which have the ability to modularly increase the size of the solar power installation size over time and thereby managing capital investment risk. CSP technologies are not included in this assessment due to the large upfront capital investment required for a utility scale implementation. The solar resource option assessment examined commercial installations on the utility side of the meter with commercial scale solar installations sized at 5 MW. A summary of the technical and financial results for the

This analysis is a significant short coming in the BC Hydro IRP. The anlaysis of technological developments is becoming critical because the next 20 to 30 years will likely see a dramatic change with regard to the viability of alternative energy sources such as solar energy.

The BC Hydro consideration of this potential did not consider the distributed energy version of solar energy, where it is integrated into functional parts of buildings. Already in the US utilities are noticing significant impacts related to customer installation of solar panels.

The CEC has a report reviewing the technological development of solar energy and forecasting the timing of arrival in BC of the point of grid parity and economic viability of the solar technologies. There are also other very important technology developments, which will affect the planning period. For instance the wind power technologies continue to show cost reductions and increased competitiveness. Forecasting technology over time is a much more critical requirement for resource planning now than it has been in the past.

The resolution of the world's GHG issues will likely depend heavily on the path for technological developments and it is becoming increasingly likely that major hydroelectric projects will no longer be the most cost effective renewable energy sources.

The BC Hydro IRP would be improved significantly if it were more robust with respect to its review of technology and how to position its plans accordingly. The CEC recommends that the government and BC Hydro pay particular attention to this area of concern.

Short Term – Capacity Bridge with Market & CRT

The BC Hydro plans for capacity bridging using market supply options and the Columbia River Treaty (CRT) resources is sound and sensible planning and should continue to be options available to BC Hydro as needed.

BC Hydro should also be able to also rely on gas plant additions for capacity if and when the province can move to more appropriate 'Energy Plan' and Clean Energy Act (CEA) criteria.

Site C & Peace Wind – Transmission GMS to Kelly Lake

Given the economic developments in the North of BC and the potential values for energy between the south of BC and the north, the strengthening of this transmission backbone is likely a useful investment.

The CEC supports advancing work on the transmission system from GMS to Kelly Lake, subject to a broader analysis of requirements in the event that Site C becomes delayed. There are many relatively low cost steps that can be taken to improve the flexibility of BC Hydro to respond to transmission needs more closely to the timing of need and these steps should be taken.

South Peace Transmission

The CEC supports the proposed review of options for the South Peace Transmission planning and notes that it believes that BC Hydro should be enabled to looking at natural gas solutions with carbon tax included.

Ft Nelson – Procurement

The CEC supports investigation of options for the Fort Nelson area and believes that BC Hydro should be enabled to look at natural gas options with carbon tax included.

4. Managing Resources

Portfolio Cost Management	4. Optimize existing portfolio of IPP resources	Optimize the current portfolio of IPP resources according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need.
	5. Customer incentive mechanisms	Investigate incentive-based pricing mechanisms over the short term that could encourage potential new customers and existing industrial and commercial customers looking to establish new operations or expand existing operations in BC Hydro's service area.

Managing Existing & Committed Resources

BC Hydro has been in the process of managing their existing and committed resources as well as continuing acquisition initiatives, in light of the current surplus of power. The following table shows the initiatives and their anticipated results.

Table 4-16 Cumulative Changes to Incremental Resource Additions, Energy (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
EPA Terminations and Deferrals	-497	-257	-156	-156	-156	-156	-156	-157	-156
EPA Renewals	-58	-52	273	385	526	819	889	1,147	1,270
New EPAs (SOP)	-467	-440	-414	-387	-361	-334	-308	-175	-46
DSM	-763	-747	-582	-352	0	0	0	0	0
VVO	-86	-129	-193	-225	-235	-248	-256	-252	-248
Net Change	-1,872	-1,626	-1,072	-735	-226	81	170	563	820

Reducing EPA Deferrals

Delay of IPP in service timing and termination of IPP contracts in breach of their terms and conditions is of course useful. However, the resource management issues above highlight the need for BC Hydro to make a substantial overhaul of its resource acquisition processes. Trimming the acquisition of new supply through the Standing Offer Program (SOP) is also necessary and useful.

Given the limited benefits obtained from managing the EPAs it is doubtful that the process was optimal. There are complexities to the management of EPAs at this time after their signing but where the EPA conditions are breached BC Hydro likely has had more ability to manage over supply than it has used. We have very limited information on this issue, there is no BCUC oversight to provide openness and transparency and it is not possible to assess this issue specifically. Therefore we are only left with the option of remaining skeptical.

When developing EPAs for acquisition of new supply BC Hydro needs to have more control over the in service date timing for the projects. BC Hydro needs to have rights with respect to the terminal values of the projects, which are essentially funded and paid for by the EPA contracts. BC Hydro needs to give serious consideration to utilizing the utility's lower cost of capital to avoid the excessive costs of IPP supply.

EPA Renewals

> be renewed. These EPA renewal planning assumptions would result in about 1,800 GWh/year of firm energy in F2021 and about 6,400 GWh/year of firm energy in F2033.

> By way of illustration, renewing about 2,000 GWh/year by F2021 would cost about $2.5 billion (through to F2033 in as spent dollars).

It is essential when examining the potential for renewal of supply from IPPs that BC Hydro realize that its customers have already paid for the capital costs of the investment and that the trailing terminal value being sold back to BC Hydro amounts to paying for this power again. To the extent that there are options for limiting this excessive cost to BC Hydro rate payer, particularly working with government, BC Hydro should do everything possible to ensure that any renewals required are managed to lower costs and to the load requirements.

> section 8.2.4, BC Hydro should be able to benefit from depreciated assets by negotiating a lower energy price recognizing that the seller's opportunity cost is selling into the spot market. Section 5.6 of this IRP contains BC Hydro's reference (mid) spot market forecast of prices at Mid-C ranging from about $25/MWh to about $40/MWh over the next 20 years.

It will be most unfortunate if BC Hydro ends up renewing EPAs at BC Hydro's LRMC effectively paying again for the assets its customers have already paid for in the initial contracts.

VVO Reductions

The Voltage, Volt-Ampere Reactive (VAR), Optimization (VVO) reductions are potentially valuable initiatives. The cut backs under the planning assumptions may not be warranted.

Customer Incentive Pricing

Using electricity pricing incentives to accomplish attraction of business to BC is likely a very poor idea. This concept relies on the perception that because there is surplus power the power is cheap and inexpensive and may be used to create incentives.

First, incentives to existing customers will result in a transfer of costs to other customers. Second, incentives provided to new customers, coming into the province, risks funding a competitor to existing business.

Other problems relate to creating a dependence on the lower power costs provided and then becoming the instrumental factor shutting down the business when the incentive must be removed.

BC's industrial sector with its energy intensive businesses will need something much more fundamental to deal with the future and this should be the focus of BC Hydro and the government.

The last significant incentives provided by BC Hydro were given to IPPs, which among other benefits received firm prices for non-firm power. The result has been quite specific in terms of creating costly power for BC Hydro ratepayers.

The discussion around this point should be framed much more in terms of what benefits BC Hydro can obtain from specific arrangements with customers.

The CEC recommends that BC Hydro and the government tread very lightly when it comes to providing incentives and ,if they are going to be considered, the benefits back to BC Hydro rate payers should be clear defined and significant.

5. Supporting LNG

Supply-Side Resources	10. Explore natural gas-fired generation for the north coast	Working with industry, explore natural gas supply options on the north coast to enhance transmission reliability and to meet the expected load.
	11. Explore clean energy supply options, if LNG demand exceeds available resources	Explore clean or renewable energy supply options and be prepared to advance a procurement process to acquire energy from clean power projects, as required to meet LNG needs that exceed existing and committed supply.
Transmission Resources	12. Advance reinforcement of the transmission line to Terrace	Advance reinforcement of the existing 500 kV transmission line from Prince George to Terrace, which includes development of three new series capacitor stations and improvements in the existing BC Hydro substations to be available by F2020.
Other	13. Horn River Basin and northeast gas industry	Continue discussions with B.C.'s northeast gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.

LNG Plant – Criteria for Industry

The LNG industry is an important new initiative in BC. The industry operates in a worldwide market and must negotiate supply contracts with customers in international markets. Their cost-effectiveness will be critical to their competitiveness and success.

They share these attributes with other businesses in the industrial and commercial sectors of the province. They have been provided with a special consideration of having their use of natural gas, to provide the energy for their processes, designated as clean. The rest of the BC industry should be questioning why they are not accorded similar treatment as they face similar conditions.

The LNG power requirements and facilities to serve them are expected to be 100% controlled by the LNG plant proponents. This control enables them to make decisions to be as cost-effective as possible when committing the very large investments needed to compete in this international market. The LNG industry is expected to rely on natural gas compression drives for their LNG production processes and this will limit the opportunities for BC Hydro or the government to provide clean renewable power into the process.

LNG Plant – Ancillary Facility Loads

BC Hydro is focused on supplying the ancillary facilities at the LNG plants with power supply and estimates that 3000 GWh/year may be required.

One of the issues that will arise from this is that the cost of supplying this energy will be well in excess of the existing industrial rates for BC Hydro's existing customers. This can lead to significant cost increases to all BC Hydro customer rates if this is the case.

In particular the Site C project is the incremental supply project which would be relied upon to provide the power. The Site C power will cause accounting costs, which would be paid for by BC Hydro customers and would exceed industrial rates and the levelized economic evaluation costs used in the IRP. The cost impacts and rate increases would be significant relative to the absence of a Site C power acquisition.

If the LNG proponents are asked to pay rates for the BC Hydro power, which would substantially exceed other industrial rates and in particular exceed their other self-generation power supply options, it becomes a significant uncertainty as to whether or not BC Hydro will be supplying this power indefinitely.

LNG Plant – Clean Energy Requirement

The province has made commitments that it will have the cleanest LNG plants in the world. Presumably the LNG proponents will be paying for a carbon tax or carbon offsets to accommodate a view that they are the cleanest in the world. Possibly the concept that BC Hydro would be providing clean renewable power to their ancillary facilities is intended to add to this clean requirement. Likely, clean renewable power will be more expensive than the onsite power supply from natural gas with a carbon tax or carbon offsets.

The CEC has a report which may provide a means for meeting the LNG proponent's need for control of their plants and power supply while at the same time enabling a clean and renewable supply at a cost comparable to the LNG self-supply options. The CEC recommends that BC Hydro and the government may want to engage in developing an understanding of how this may be done.

Reinforce Transmission 500 KV

The CEC supports upgrades of the transmission system supply into the North Coast, Terrace and Prince Rupert area.

Horn River Energy Requirements

The transmission supply options for the north east of BC into the Horn River area are quite costly. The use of local gas fired generation options would likely be more cost-effective.

The CEC recommends that BC Hydro in considering options for the north east ensure that among the options being considered is natural gas fired generation.

6. Planning for the Unexpected

Supply-Side Resources	14. Advance Revelstoke 6 Resource Smart project	Advance the Revelstoke Generation Station Unit 6 Resource Smart project to preserve its earliest in-service date of F2021 with the potential to add up to 500 megawatts of peak capacity.
	15. Advance GM Shrum Resource Smart project	Advance Resource Smart upgrades to GM Shrum Generating Station Units 1–5 with the potential to gradually add up to 220 MW of peak capacity starting in F2021.
	16. Investigate natural gas generation for capacity	Working with industry, explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.

Capacity Requirements

The advancing of the Revelstoke 6 generating station and the advancing of upgrades to GM Shrum units 1 to5 may make sense as the renewable energy supply acquired comes fully in service the capacity requirements to be able to meet loads will increase. These are expensive projects and final commitments to their implementation should be done only in light of other potential capacity supply, such as the capacity supply that can come from natural gas plants, which may become viable options.

Natural Gas Supply Options

There is little doubt that developing the necessary options for natural gas supplied power and advancing the preparations for potential implementations will be a very important step in controlling costs of supply. This work needs to be done under a new set of guidelines to allow BC Hydro to find the more optimal arrangements for planning its system.

The CEC recommends that the government work with BC Hydro to enable optimal planning for natural gas fueled resources in the BC Hydro system. The CEC supports the initiatives to advance the planning for natural gas fueled resources in the BC Hydro system.

Risk of Surplus

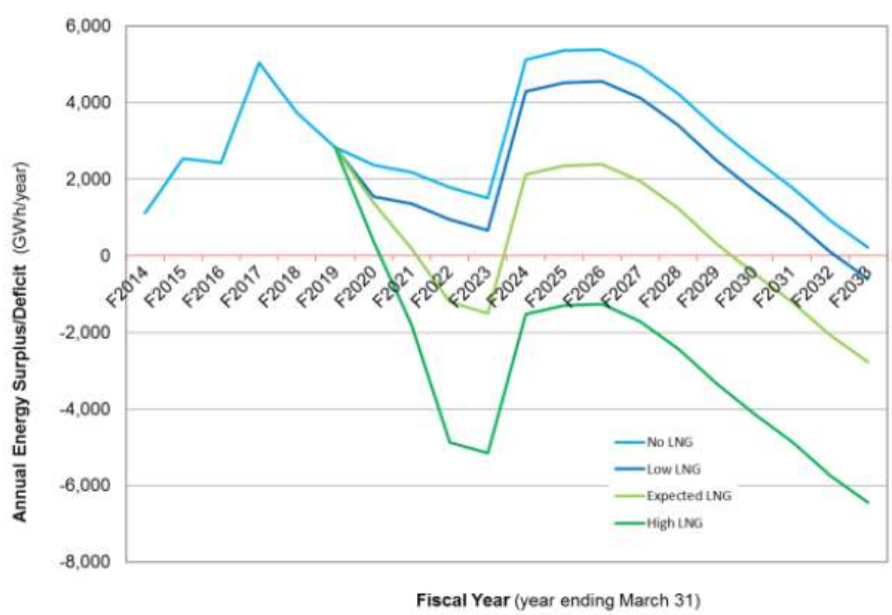
The following shows the expected energy surplus from 2017 through to 2021 or 2023 depending upon the scenario. Of course from 2013 to 2016 the BC Hydro system will also be expecting a surplus of energy.

Table 4-18 Energy Surplus/Deficit (F2017 to F2023, F2028, F2033), GWh

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2028	F2033
Surplus/Deficit with Incremental Resources and Expected LNG	5,041	3,725	2,828	1,366	179	-1,216	-1,886	-3,864	-7,886
Surplus/Deficit with Incremental Resources without Expected LNG	5,041	3,725	2,828	2,366	2,179	1,784	1,114	-864	-4,886

The following graphic demonstrates this surplus shown above and the potential for surpluses in the event Site C becomes a committed project.

Figure 6-10 System Energy Surplus/Deficit after BRP Implementation under Different LNG Load Scenarios



The risks of oversupply are the most prevalent risks in the BC Hydro system. The dependence of this risk in the future on the LNG plant proponent's decisions to use BC Hydro power is clearly evident in the graphic. The future rate increases for all BC Hydro customers, which come with these choices, will be significant if the power is supplied at existing rates.

The CEC recommends that BC Hydro and the government specifically include in the IRP planning management of surplus power risks.

7. Integrated Resource Planning

One of the most important issues in planning for BC Hydro is the cost impact of various plans and in particular their rate impact implications for customers. The fact that the IRP does not explicitly address the rate impacts of the recommendations is a serious concern with the IRP process.

Another concern in the IRP is the myriad of constraints introduced into the BC Hydro planning through the Clean Energy Act. These constraints are single metric constraints and as such they do not allow for the implementation of appropriate tradeoffs between the values and objectives involved which would be an appropriate context for BC Hydro's planning.

The IRP consultation process with the public did not adequately deal with the cost impacts of choices and the potential rate impacts of the costs. As a consequence the public input to the process cannot be relied upon to provide a credible basis for support.

BC Hydro resource planning is a technical task in large measure and its review requires a fairly deep and involved process of examination. The IRP process has enabled only a limited review and little to no time to explore the options and particularly the policy options which could result in a more optimal plan.

In order to manage the costs and rate impacts of the BC Hydro resource planning there is a need to optimize the value of existing assets. The BC Hydro planning has not adequately addressed this, in part because of imposed planning constraints and in part because of a failure to consider developing information about opportunities which may involve a change of policy for the government to consider.

The CEC recommends that the government consider, as it addresses this IRP, development of a new energy plan as context for the future and legislative changes to accompany this new context so that more optimal integrated resource planning can be accomplished for the benefit of BC and the BC Hydro ratepayers. The CEC recommends that the government keep this IRP in the process of consideration, while a new context is set and more optimal recommendations can be formulated as an update to this proposed plan.

WRITTEN SUBMISSION FROM:

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October 18, 2013

BC Hydro c/o Randy Reimann
BC Hydro Integrated Resource Planning
333 Dunsmuir Street, 10th Floor
Vancouver, B.C. V6B 5R3

Dear Mr. Reimann,

Further to your invitation to Technical Advisory Committee (TAC) members to provide comments on BC Hydro's 2013 Integrated Resource Plan (IRP), please find attached FortisBC's submission. FortisBC commends BC Hydro on the extensive work it has undertaken for the IRP and appreciates the opportunity to review it and provide comments. We have organized these comments under the requested headings set forth by BC Hydro and we have included a number of additional comments under the General Comments section.

Please do not hesitate to contact me at (604) 592-7516 or jason.wolfe@fortisbc.com if you have any questions or concerns regarding these comments.

Sincerely,

Jason Wolfe
Director, Market Development

Introduction

BC Hydro has requested input from stakeholders in regard to its 2013 Integrated Resource Plan (IRP) under headings provided for specific plan topic areas. As a major stakeholder in the delivery of energy to customers in B.C. and a member of the Technical Advisory Committee to BC Hydro's Integrated Resource Plan, FortisBC would like to provide the following comments and input. FortisBC has endeavored to follow the proposed format by providing comments under each of the headings as requested by BC hydro below, and notes that there are a number of important issues that do not lend themselves to a fulsome discussion within these headings. We are therefore providing these comments under the heading titled "General Comments".

General Comments

1. *Electric Load Avoidance*

FortisBC has outlined the benefits of electric load avoidance (ELA) in helping to cost-effectively meet the gap between annual and peak electricity demand and supply for BC Hydro over the planning horizon on a number of occasions.[1] The greatest residential impact on BC Hydro system capacity and generation is space and water heating load, energy which is better provided by high efficiency gas appliances. It is the opinion of FortisBC that ELA is one of the single most direct methods to mitigate potential incremental electrical load. In contrast, the absence of an ELA approach indicates that BC Hydro is continuing to add electricity load for these end uses and then spending DSM funding to try to reduce these loads through Power Smart programs. This is fundamentally inefficient.

FortisBC continues to believe that ELA should be an important part of BC Hydro's resource portfolio analysis and notes that consideration of ELA is absent from the 2013 IRP. As such, we have included our 2008 LTAP Review Final Submission as Attachment A to these comments. FortisBC urges BC Hydro to review that submission again and consider ELA as a resource alternative in its 2013 IRP. The BC Clean Energy Act and the Province's new Natural Gas Strategy have both been brought forward since the completion of the 2008 LTAP regulatory proceeding, and FortisBC believes that both the CEA and the Natural Gas Strategy provide a framework that support ELA activities by BC Hydro.

British Columbia's Energy Objectives are defined in Part 1, Section 2b of the Clean Energy Act, which include:

> *"…to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%...*
> *…to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America…"*

FortisBC believes that ELA meets the objectives of the Clean Energy Act, and that given the provincial government's pronouncement of the clean attributes of natural gas in reducing global greenhouse gas

[1] FortisBC (then Terasen Gas) described ELA in detail in its final submission during the B.C. Utility Commission's regulatory review of BC Hydro's 2008 Long Term Acquisition Plan and again in response to BC Hydro's request for comments to the 2012 IRP, "IRP Technical Advisory Committee Written Submissions August 2012."

emissions, ELA activities which result in natural gas use for thermal end uses also support the government's intent to use the most efficient fuel for any given use.

"Electric Load Avoidance DSM", as referred to in the attached submission (Attachment A – 2008 LTAP Review Final Submission), involves the provision of cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for heating applications but rather to adopt gas appliances for heating applications. Electric Load Avoidance DSM incentives can be structured in a variety of ways, but have as a common objective to mitigate the potential for the customer to choose electricity as an energy choice for space and water heating, thereby adding load that must be served at BC Hydro's significant marginal cost of supply.

Load avoidance and load reduction have the same value to BC Hydro customers in terms of BC Hydro's avoidance of new high cost supply; however load avoidance provides additional certainty that new supply will not be required over the long useful life of the installed non-electric appliance. It does not seem rational to add electric heating and hot water load that must be served by adding costly new generation and transmission resources, only to subsequently expend ratepayer funds to attempt to induce those same customers to reduce their electricity usage for these end uses (Note that once installed, electric space and water heating appliances are not easily changed out to gas appliances and therefore BC Hydro is "stuck" providing service to these customers for the building life of the customer.) It would be far more efficient not to have attracted that electric heating and hot water load in the first place. Further, it would be more cost-effective for customers. Current natural gas rates for residential customers are approximately $7.86/GJ. BC Hydro's Tier 2 RIB rate is the equivalent of $27.15/GJ. Cost-effective incentives could be tested first in new construction and expanded to retrofits, as it may be more efficient to encourage customers to avoid the electrical load with natural gas (as the alternative) initially at the design stage of construction.

Across B.C.'s border in Washington State, Puget Sound Energy, a combined gas and electric utility, actively pursues Electric Load Avoidance. Puget Sound Energy offers fairly significant rebates to customers to convert from electric space and water to natural gas space and water heating.[2] They do so because it makes financial sense to add customers where they have capacity to do so – on the natural gas system – and avoid customers where they are capacity constrained – on the electric system. The same holds true in British Columbia. Furthermore, in B.C., the cost of associated greenhouse gas emissions is already factored into the natural gas cost through the consumer-based carbon tax.

The current situation is different to that in 2008; today there is the Clean Energy Act, along with a subsequent designation of gas-fired power generation for LNG exports as clean energy. The rationale for designating gas-fired generation as clean for LNG exports is that the export of British Columbia's LNG will result in lower emissions in Asia. Given this argument, it is reasonable and logical to conclude that BC Hydro should also pursue Electric Load Avoidance DSM by encouraging the use of natural gas for end use heating applications, not only because it is a more cost efficient option for BC Hydro rate payers, but it can also result in lower carbon emissions in the Pacific Northwest and Alberta.

Although the Clean Energy Act defines "demand side measure" such that the current definition specifically excludes rates, measures, actions and programs that would encourage a switch to an energy form such that the switch would increase greenhouse gas emissions in British Columbia, government has

[2] http://www.pse.com/savingsandenergycenter/ForHomes/Pages/Converting-to-Natural-Gas.aspx

also recently established a position that takes a more global view of greenhouse gas emissions than just looking within British Columbia. In its LNG Strategy, the government states that "climate change is a global issue".[3] Government has endorsed the use of natural gas to power the LNG facilities planned for British Columbia through an amendment to the Clean Energy Act, after Premier Clark stated in an address to the B.C. Business Council that natural gas for this use would be considered "clean". Thus we can conclude that with enough political will, the current definition of demand side measure in the Clean Energy Act could be amended to allow for Electric Load Avoidance DSM that includes the customer choosing natural gas over electricity for appropriate end-uses.

The starting place for the Government's analysis of whether Electric Load Avoidance DSM should be used to produce more efficient price signals must be its favourable impact on the rates paid by BC Hydro customers. From a total resource perspective, BC Hydro customers collectively stand to benefit from the pursuit of Electric Load Avoidance DSM identified as having a Total Resource Cost ratio of benefits to costs of more than one.

FortisBC urges BC Hydro to consider evaluating its need for new clean resources under two additional conditions:

- What would be the need for additional resources if ELA DSM were implemented by BC Hydro? And,
- What could the resource mix look like if all natural gas-fired generation were treated consistently as clean electricity resources given the potential to offset coal-fired electricity generation within the electricity trading region?

Natural gas-fired generation can provide firm capacity throughout the year and would provide the additional benefit of balancing non-firm renewable resources.

2. Carbon Price Forecasts

FortisBC notes that BC Hydro has taken steps to address the most recent developments in GHG policies both within and outside of B.C. in its range of GHG price forecasts. However, certain items upon which scenarios are based remain unclear:

- Scenarios 3 and 5 cite lack of international agreement on GHG regulation due to low levels of public support for GHG regulation in the U.S. What determines 'low levels of public support for GHG regulation in the U.S.' (Market Scenarios, p.5-8)? Scenarios 3 and 5 reflect high economic growth scenarios thus factors that influence support for GHG regulation such as discretionary income are relatively high. The factors that determine low levels of public support for GHG regulation in the U.S. remain unclear.
- Section 5.4.2.3 on U.S. policy states that California's cap-and-trade program has a price floor of US$10.71/tonne and ceiling of $40, $45 and $50/tonne. Given this information, FortisBC questions why GHG price forecast market scenarios 3, 4 and 5 show California's GHG price forecast as ranging from CAD$67.5 to $145.1/t$CO_2$e (GHG price forecasts, p.5-21/22) and believe this oversight may create bias where these scenarios are used.

[3] B.C. Ministry of Energy, Mines and Natural Gas, "Liquified Natural Gas: A Strategy for B.C.'s Newest Industry", 2012, p. 7.

3. Managing GHG Emission Reductions

Recognition That Actions in B.C. Assist in Global GHG Emission Reductions

The Clean Energy Act of 2010 sets the provincial objective to pursue fuel switching activities where carbon emissions are reduced within B.C. The more recent Natural Gas Strategy and announcement from the B.C. Government that it believes exports of natural gas will help to reduce global carbon emissions even though carbon emissions in B.C. may rise is a government acknowledgement that activities should be sought out within B.C. that can reduce carbon emissions beyond the province's borders. FortisBC believes that while the Clean Energy Act sets out the provincial objective of switching from high carbon to low carbon fuels, the recognition that natural gas plays a clean energy role in B.C. and around the world suggests that BC Hydro should examine the potential for ELA approaches that include natural gas as an alternative fuel. In this way, any renewable electricity conserved in B.C. might be made available for export to offset higher emission electricity generation in neighbouring jurisdictions, recognizing that export of clean electricity is also a policy set out in the Clean Energy Act.

Climate Policy-Driven Electrification

BC Hydro has retained MK Jaccard and Associates to "study the associated issues and understand the potential for climate policy driven electrification . . . model the impact of climate policy on energy related GHG emissions in B.C. to provide further information on the end uses where electric load could be expected to increase in response to various levels of carbon pricing" (Section 6.7). Additional clarification on how costs were derived are required to enable stakeholders to more fully understand this model and analysis. FortisBC expresses concern that the workings of the model are not clear to outside stakeholders and requests to be part of the ongoing electrification analysis. Further, FortisBC believes that the review should be consistent with government policy that is moving to an increased use of natural gas in BC.

4. Generating B.C. Electricity from B.C's. Natural Gas

Growth in natural gas-fired generation has occurred across North America, including the Pacific Northwest, due to its ability to quickly replace coal fired generation and its ability to balance renewable resources. FortisBC recognizes that BC Hydro is bounded by provincial regulation as to the amount of natural gas-fired generation it can rely on to supply future electricity demand, and that BC Hydro has examined alternatives to ensuring it complies with the 93% clean energy requirement from the CEA within Chapter 6 of the IRP. BC Hydro has, however, limited the scenarios in which gas-fired generation is examined to scenario 2 only. FortisBC would like to see this analysis expanded to include more scenarios for resource gap, north Coast, DSM option, Site C and wind integration alternatives that include gas generation as an alternative.

With the B.C. Government recognizing the value of natural gas-fired generation in reducing global carbon emissions, FortisBC believes that the definition of clean energy must be changed so that all gas generation is consistent with the new definition for gas generation for LNG exports. As such, a non-bounded (by the 93% clean energy requirement) examination of the potential for natural gas-fired generation in B.C. is a worthwhile exercise and would help inform both the B.C. Government and BC Hydro stakeholders. Such an examination should include the benefits of:

- the diversity of supply that additional gas fired generation would create,
- optimizing all existing energy infrastructure within and serving B.C.,

- the ability of B.C. renewable electricity exports to reduce regional carbon emissions,
- natural gas-fired generation as a peaking resource and as a base load resource within B.C., and
- the role that ELA can play in reducing carbon emissions on a regional basis given the expected growth in natural gas fired generation in the region.

Burrard Thermal is a valuable and cost-effective existing resource near the load centre that should play an important role in providing a capacity resource over the long term; its use should be re-examined given the recommendation above. Additional discussion of Burrard Thermal is provided in sections 7 and 9 below.

Natural gas is an economic and environmental solution for electric generation, one that is recognized by export markets as a clean alternative to oil and coal – and part of the North American strategy to combat climate change. By utilizing B.C. natural gas within our province to generate clean electricity, (rather than exporting gas for electric generation in other jurisdictions) we can keep jobs, investment, and revenues within our province.

Discussion Guide Topic Areas

FortisBC's remaining comments are set out according to BC Hydro's discussion guide topics.

5. Supporting LNG

BC Hydro is considering the use of gas fired generation in the north-east to supply electricity to serve the gas production market. Part of the justification is to help manage GHG emissions as BC Hydro states that emissions can be reduced by 0 to 16% over industry self-supply (page 8-58). FortisBC agrees with BC Hydro and the B.C. Government's consideration of gas-fired generation for LNG development; using the same reasoning of managing GHG emissions, natural gas can help reduce GHG emissions in B.C. through efficient use in thermal heating applications. In addition, if BC Hydro were to conduct a non-bounded (by the 93% clean energy requirement) examination of the potential for natural gas-fired generation in B.C. (as outlined in point 4 above), BC Hydro would find natural gas-fired generation as a cost-effective alternative to other resource options including Site C.

6. Conserving First (DSM recommended actions)

FortisBC agrees that conservation programs that help reduce peak electricity demand can be valuable. Since space heating load is a peak and seasonal load, FortisBC believes demand side management programs and other mechanisms that might be developed to encourage ELA can be among the most effective mechanisms in reducing peak demand. Peak demand reductions resulting from ELA activities will also be among the most assured reductions since the load is avoided from the outset, rather than based on programs that aim to reduce consumption after it has been added to the system. Please refer to the Electric Load Avoidance section above, and review the attached final submission from FortisBC (then Terasen Gas) in the 2008 LTAP regulatory proceeding for a full discussion of the importance of considering ELA in the BC Hydro IRP.

7. Powering Tomorrow

Site C

On page 8-49 of the IRP, BC Hydro states that Site C is not a marginal resource because Site C is needed. During the TAC meetings, BC Hydro was challenged as to whether or not Site C was the best solution to meeting the future demand. Site C is a massive government infrastructure project set to come on line more than ten years from now. Costs are currently pegged at nearly $8 billion. The justification for Site C only makes sense if a number of factors materialize (such as load) and using generous assumptions (discount rate/period). Even under these positive assumptions, Site C is a more costly resource than gas fired generation by anywhere from $20-50/MWh (depending upon which scenario/assumptions are used). If load does not materialize, assumptions are changed or costs increase, Site C may look less viable. FortisBC would encourage the government to look at changing the 93% clean energy requirement such that gas fired generation is an option. If this occurred, customers would be better off due to lower costs and therefore lower rates.

Some of the Site C inconsistencies and challenges are noted below:

- The Unit Energy Cost for Site C ($94/MWH) is compared to a Clean Energy Block ($153/MWh) and to two different Clean + Thermal Generation Blocks ($128 to $130/MWh) (page 6-32). However, it appears that BC Hydro (Site C) projects and IPP projects (including gas-fired generation) are evaluated on a different investment period basis, disadvantaging gas-fired generation and other IPP alternatives.
- Does BC Hydro expect Site C to have a cost of energy less that $85/MWh or lower than the band width of $85-$100 MWh for the LRMC outlook?
- A number of assumptions that BC Hydro is using need to be vetted, for example depreciating the asset over a 70 year life and the assumed discount rate.
- Given the demand for workers and materials that the Northern LNG plants will create, what is the level of confidence in the forecast costs of Site C?
- Given consultation issues with First Nations, what level of confidence exists in achieving the planned commercial operation date of Site C?

The cost impact of Site C may be significant and it is vital that other options be considered to reduce the potential impact on rates if project costs should escalate. The section, ‘Execution’ (page 8-40), outlines BC Hydro’s options to bridge capacity resources until Site C is completed. These are the following:

- Continue to monitor market conditions and U.S./Alberta transmission system developments to facilitate and ensure that BC Hydro has access to up to about 200 MW of market purchases during all hours of the year with specific focus on BC Hydro’s winter system peaking conditions.
- Manage Canadian Entitlement, trade commitments and market optimization to about 200 MW of the Canadian Entitlement to be available to back up the 200MW of market purchases.

Given that Site C is a high risk project on the basis of both cost overruns and completion schedule, this plan does not appear robust enough to provide an adequate contingency plan.

Bridging Capacity

FortisBC discussed the issue of a more fulsome examination of natural gas fired generation as a resource option under the heading "Overall Comments". Such an examination should include consideration of using Burrard Thermal based on the B.C. Government's proclamation that natural gas-fired generation supporting LNG exports is designated as clean and based on the B.C. government's recent Natural Gas Strategy. FortisBC believes that Burrard Thermal is a valuable cost-effective, existing resource for the customers of BC Hydro and its future use should be more completely articulated in the IRP. In addition, there are other potential capacity options in the province such as the Waneta Expansion project, which can be used to meet this short-term capacity gap.

8. Managing Resources (Managing costs associated with BC Hydro's current portfolio)

BC Hydro Avoided Cost

BC Hydro acknowledges that due to various requirements set forth in the B.C. Clean Energy Act, market prices do not accurately reflect the avoided cost of electricity, but rather this is best represented by the costs of DSM activities and Electricity Purchase Agreements. Despite the challenging DSM requirements set out in Clean Energy Act (66% of incremental load growth), BC Hydro believes it can achieve this goal at a relatively low cost. FortisBC expresses concern over the result if BC Hydro does not achieve the planned levels of DSM at the assumed price.

Furthermore, BC Hydro has identified that they hold a number of EPA's with IPPs that are reaching the end of their initial terms. Under the current EPAs, these generating facilities continue to be among BC Hydro's lowest cost of sources of clean energy from IPPs, delivering energy to BC Hydro at prices much lower than BC Hydro's avoided cost for new clean resources. In addition, as operating projects these provide BC Hydro a high level of supply certainty. Nevertheless, BC Hydro has indicated that intends to renegotiate the terms of these EPAs based on prices that are between sellers' opportunity cost (Mid-C minus wheeling and losses) and the forecast cost of service assuming past capital expenditures have been recovered over the initial term). FortisBC challenges the assumption that the IPPs holding these EPA's will have fully recovered initial and recurring capital expenditures, and believes that this strategy could result in a number of existing and cost effective operating facilities ceasing to operate. At the same time, BC Hydro continues to contract for new projects under Standing Offer Program or develop other new resources at much higher unit costs. FortisBC believes that BC Hydro should allow these projects to continue to delivery energy to BC Hydro under the existing EPA terms or that any new terms should consider BC Hydro's avoided cost for new clean firm resources in BC and the IPP's having a fair and reasonable opportunity to recover both variable costs and the capital invested in the projects.

Need to Consider Holistic Energy Planning

Increasing rates for BC Hydro rate payers affects FortisBC electric and gas customers. FortisBC believes that it may be valuable for FortisBC and BC Hydro to jointly assess future requirements and consider options that may more efficiently meet the requirements of both electric utilities in the province on a combined basis. BC Hydro's IRP has only considered integrated resources within the BC Hydro entity, but has not considered integrating with other providers of energy within the Pacific Northwest. BC Hydro could arrive at an improved solution by integrating planning with both FortisBC gas and electric divisions, which would result in better optimization of all energy infrastructure in B.C. and lower rates for all end use customers. To support this effort, FortisBC believes that the definition of clean energy needs to be changed so that all gas-fired electricity generation is consistent with the new definition for gas generation for LNG exports. Please refer to section 4 for additional details on the potential for natural gas-fired generation in B.C.

In addition, the Contingency Resource Plan, Supply Side Resources states the following action item 16: "Investigate natural gas generation for capacity" which is defined as:

> "*Working with industry, to explore natural gas supply options to reduce their potential lead time to in-service and to develop an understanding of where and how to site such resources, should they be needed.*"

FortisBC supports BC Hydro working with industry to support natural gas-fired capacity options in order to provide a current and more balanced comparison of these options to other capacity resource options. When does BC Hydro intend to initiate this plan and will it be available for stakeholders to review?

IPP Power

Even if the current Electricity Purchase Agreements were extended, expiring run-of-river EPAs are likely to be BC Hydro's lowest cost source of clean power. Given the inherent risks of achieving DSM targets and the fact that the Standing Offer Program remains open to new projects at $100/MWh, why does BC Hydro now plan not to renew 25 percent of expiring run-of-river EPAs?

Resource Options

The Non-Integrated Areas (NIA) department within BC Hydro operates, maintains and manages all aspects of energy supply (generation, distribution and customer service) in 18 communities across 10 remote B.C. locations that are not currently connected to the BC Hydro integrated electrical system. NIA major assets include about 50 diesel generating units (stationary and mobile) and it is these stations along with future stations that should be considered for conversion to LNG-fueled generation. This would provide a substantial decrease in GHG emissions compared to using diesel fuel, as well as a significant decrease in operating cost.

Future of the Burrard Thermal Generating Station

The Burrard Thermal Generating Station is now excluded as a component of BC Hydro's Integrated Resource Plan pursuant to subsection 3(5) and 6(2)(d) of the CEA:

> *(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.*
>
> *6(2)(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.*

As a result of the Burrard Thermal Electricity Regulation, Burrard Thermal cannot be relied on for dependable capacity after Mica Unit 6 goes into service in 2016. Nevertheless, there may be a more cost-effective role for Burrard Thermal that has not yet been proposed.

9. Planning for the Unexpected (Contingency Plans)

Site C

Please refer to Section 7 for comment on Site C contingency plans.

Planning Reserve Margin (PRM) and Contingency Resource Plan (CRP)

PRM can be seen as the capacity buffer to deal with unexpected load increase and/or generation losses. BC Hydro has estimated its PRM at around 14% of its existing capacity and added this to the mid load to come up with the capacity requirement, upon which capacity gaps were calculated. The self-sufficiency requirement was then applied in such a way that only resources within the province could be used to meet gaps in the base case. Since PRM is intended to be used for contingencies as opposed to expected load, why did BC Hydro apply the self-sufficiency rule rather than relying on other outside resources such as the Canadian Entitlement?

In addition, why does BC Hydro not plan to use PRM to deal with higher than expected load (or DSM to deal with lower than expected load, or both), but rather it turns to the Contingency Resource Plan? To add, Section 8 of the 2013 IRP does not clearly specify the factors that trigger the CRP and additional clarity is necessary.

Attachment A – FortisBC Comments on

BC Hydro 2013 Integrated Resource Plan

Terasen Utilities' Submission to the BCUC, dated April 27th, 2009

With respect to BC Hydro's 2008 Long Term Acquisition Plan

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April 27, 2009
File No.: 240148.00595/14797

BY ELECTRONIC FILING

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Utilities
An Application by BC Hydro and Power Authority for the Approval of 2008 Long Term Acquisition Plan

We enclose Submissions on behalf of the Terasen Utilities in respect of the above mentioned matter. Twenty hard copies of the Submissions will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

* Fasken Martineau DuMoulin LLP is a limited liability partnership and includes law corporations.

IN THE MATTER OF

THE UTILITIES COMMISSION ACT S.B.C 1996, CHAPTER 473

AND

AN APPLICATION BY BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)

FOR THE APPROVAL OF 2008 LONG TERM ACQUISITION PLAN (2008 LTAP)

FINAL SUBMISSIONS OF THE TERASEN UTILITIES

APRIL 27, 2009

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FINAL SUBMISSIONS OF THE TERASEN UTILITIES

APRIL 27, 2009

I. INTRODUCTION AND OVERVIEW

A. Introduction

1. BC Hydro faces a significant challenge in closing its forecasted load-resource gap. BC Hydro is to be commended for advancing a significant portfolio of cost-effective electric *load reduction* demand-side measures ("DSM") that will assist BC Hydro customers to reduce their electricity consumption. However, DSM can also be directed at electric *load avoidance*. Where energy source alternatives exist for particular end use applications, BC Hydro's resource analysis should extend to whether electricity is, in the words of the Energy Plan, the "right fuel, for the right activity, at the right time".[1]

2. "Electric Load Avoidance DSM",[2] as referred to in these Submissions, involves providing cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for end uses where electricity is not

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1 The BC Energy Plan states: "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas." See Exhibit C13-5, at 61.

2 We have used the term "Electric Load Avoidance DSM" in these Submissions, rather than the term "fuel switching" to emphasize that the purpose of these measures is to avoid inefficient electric load. Also, the term "fuel switching" is subject to being misconstrued as referring exclusively to measures directed at existing customers that have already installed electric appliances, whereas new customers that have yet to install any appliances are also a key target of Electric Load Avoidance DSM.

the most efficient energy source from a Total Resource Cost ("TRC") perspective. Electric Load Avoidance DSM incentives can be structured in a variety of ways, but have as their common objective to mitigate the potential for the customer to choose electricity as an energy choice for particular end use applications, thereby adding load that must be served at BC Hydro's significant marginal cost of supply, based on (i) the prospect of paying electricity rates based to a significant extent on BC Hydro's embedded costs,[3] or (ii) any differential in capital cost between electric appliances and appliances using another energy source. The incentive leaves the customer free to make the choice as to the appropriate energy source for a particular application based on a more efficient price signal from a TRC perspective. The right energy source for a particular customer, for a particular application, in the customer's particular circumstances might be electricity, natural gas, or some other energy source.

3. The starting place for the Commission's analysis of whether Electric Load Avoidance DSM should be used to produce more efficient price signals must be its favourable impact on the rates paid by BC Hydro customers. The importance of examining BC Hydro's strategies to meet the growing load-resource gap from the perspective of BC Hydro's ratepayers is evident from the legislated requirement in the *Utilities Commission Act* ("UCA") for BC Hydro to explain in its LTAP why it intends to acquire new higher-cost supply rather than to pursue this cost-effective DSM.[4] From a TRC perspective, BC Hydro customers collectively stand to benefit from the pursuit of Electric Load Avoidance DSM identified as having a TRC ratio of benefits to costs of more than one. The new emphasis in the UCA on encouraging public utilities to pursue cost-effective DSM is realized by BC Hydro pursuing cost-effective Electric Load Avoidance DSM.

4. "Government's energy objective" in the UCA "to encourage public utilities to reduce greenhouse gas ["GHG"] emissions", which reflects the Province's overall support for mitigating climate change as outlined in the Energy Plan, is also a valid consideration in the assessment of Electric Load Avoidance DSM. The evidence in this proceeding supports the

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[3] BC Hydro's Residential Inclining Block ("RIB") rate structure, which introduced a trailing block rate that moves towards BC Hydro's marginal cost of supply, helps to promote efficient energy choices by customers; however, as discussed later in these Submissions, many residential customers will see mostly the Step 1 rate, and the Step 2 rate will necessarily lag behind BC Hydro's true marginal supply cost.

[4] UCA, s. 44.1(2) (b), (f).

potential for cost-effective Electric Load Avoidance DSM to reduce GHGs on a regional basis. There are three equally compelling reasons why this is the case. Further, the end use consumption of natural gas in BC is already subject to a carbon tax, which provides price signals reflecting the cost of carbon much like BC Hydro's purchased carbon offsets will do for gas-fired electricity generation after 2016. BC Hydro should therefore regard Electric Load Avoidance DSM as a means of reducing (all else equal) electricity rates with confidence that Electric Load Avoidance DSM is consistent with government's interest in mitigating climate change.

5. The Terasen Utilities are encouraged by BC Hydro's apparent willingness to study further the potential for Electric Load Avoidance DSM.[5] The preferable approach to rejecting a part of the LTAP is for the Commission to identify key parameters of that initiative through its findings and directions in this proceeding. The Commission should require BC Hydro to file its next LTAP within 12 to 15 months of the Commission's decision in this proceeding, which represents a continuation of the two-year cycle between LTAP filing dates. BC Hydro should be directed to include in the next LTAP a proposal to pursue cost-effective Electric Load Avoidance DSM based on the outcome of its further study. Maintaining the current two-year regulatory cycle for BC Hydro's LTAP will help to ensure that pursuit of Electric Load Avoidance DSM does not languish while new, higher cost, supply initiatives (e.g. the Clean Call) proceed.

B. Organization of These Submissions

6. These submissions are organized as follows:

(a) Part II discusses the contribution of avoidable (space and water heating) load to the increasing load-resource gap faced by BC Hydro.

(b) Part III addresses the potential to avoid part of the load with cost-effective Electric Load Avoidance DSM.

(c) Part IV explains why the TRC test is appropriate for measuring the cost-effectiveness of Electric Load Avoidance DSM. It also describes the benefit to BC Hydro customers to pursuing cost-effective DSM in the form of rates that are

[5] See Transcript, Vol. 11, at 2038.

lower than they otherwise would have been in the absence of the Electric Load Avoidance DSM.

(d) Part V sets out the evidence regarding how the pursuit of cost-effective Electric Load Avoidance DSM can reduce overall GHG emissions on a regional basis.

(e) Part VI discusses how the current policy and legislative context supports the use of Electric Load Avoidance DSM to send efficient price signals to customers faced with a fuel choice for a particular application. It discusses why the policy arguments advanced by BC Hydro do not outweigh the demonstrated benefits associated with pursuing cost-effective Electric Load Avoidance DSM.

(f) Part VII contains a summary of findings supported by the evidence in this proceeding, as well as proposed Commission directives that should guide the further study of Electric Load Avoidance DSM and inputs in the next LTAP.

II. CHOICE OF ENERGY SOURCE AND BC HYDRO'S LOAD RESOURCE GAP

7. Electric Load Avoidance DSM represents an important opportunity to address a portion of the widening load-resource gap in a cost-effective manner. The following points are addressed in this Part:

(i) BC Hydro faces a difficult task in meeting its forecasted energy and capacity requirements, and attaining self-sufficiency. The load forecast in the LTAP may understate the load requirements given the potential for developments in areas such as electric plug-in vehicles.

(ii) Residential space and water heating, for instance, contributes significantly to BC Hydro's energy and capacity requirements. This creates the imperative for BC Hydro to send effective price signals to encourage its customers to make efficient fuel choices.

(iii) Cost-effective Electric Load Avoidance DSM can help to overcome inefficient price signals on a TRC basis arising from electricity rates based on embedded costs and differential capital costs, with the result that customers may choose an alternative to electricity as an energy source for particular end use applications.

A. Forecasted Energy and Capacity Shortfall and Implications for BC Hydro

8. BC Hydro's Evidentiary Update shows a forecasted energy resource deficit, before factoring LTAP initiatives, of 3,500 GWh in F2012, 7,700 GWh in F2016, 10,600 GWh in F2017, and 13,600 GWh in F2021.[6] BC Hydro acknowledges that the resource deficit is "a

[6] Exhibit B-10, Table 2-6.

significant gap to close."[7] The resource deficit to meet energy demand is increasing even with the DSM adjustment, from a 3,000 GWh shortage in F2017 and to 3,700 GWh in F2021. In F2027, BC Hydro predicts an energy shortfall of 19,100 GWh before 2008 LTAP actions and a 7,500 GWh shortfall after adjusting for DSM. Thus, even with adjustments from currently proposed DSM, the deficit between forecasted energy load and resource more than doubles within a ten-year span (from F2017 to F2027).[8]

9. The forecasted capacity resource deficit is 350 MW in F2012, 1,120 MW in F2016, 1,190 MW in F2017, and 1,720 MW in F2021.[9]

10. BC Hydro has identified several factors that may increase BC Hydro's energy requirements. First, although BC Hydro predicts DSM savings of 7,600 GWh for F2017, 9,900 GWh for F2021, and 11,600 GWh for F2027,[10] it also readily concedes that it "faces uncertainty with respect to . . . DSM savings."[11] Second, electrification of oil and gas facilities may add to the future load forecast.[12] Third, there exists the potential for significant load associated with electric plug-in vehicles.[13] Fourth, as discussed further below, since BC Hydro's load-resource balance assumes that in future years the percentage of residential customers with electric space and water heating will remain more or less as it is today (based on BC Hydro's billing data), BC Hydro's energy requirements will increase if existing customers switch to electric space and water heating during the next 20 years or if the capture rate for new customers increases materially during that time.[14]

11. These potential developments will also have capacity consequences.

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[7] Transcript, Vol. 3, at 257.

[8] Exhibit B-10, Table 2-9.

[9] Exhibit B-10, Table 2-7.

[10] Exhibit B-10, Table 2-9.

[11] Exhibit B-10, at 24; Transcript, Vol. 3, at 258.

[12] Exhibit B-10, at 12; Exhibit C13-5, at 6.

[13] Exhibit B-10, at 11; Exhibit C13-5, at 6.

[14] Transcript, Vol. 3, at 259-260; Exhibit B-10, at 11-12; see also Exhibit C13-7, at 15, BC Hydro states that all residential spacing heating and water heating load migrating from other energy sources to electricity is a low probability.

12. BC Hydro's ability to close the load-resource gap in a timely manner is critical for BC Hydro to meet the requirement to reach self-sufficiency by 2016. Lower than anticipated DSM savings will mean, for instance, that "there would likely not be time to recover through standard acquisition process. This would likely result in BC Hydro relying on the Canadian Entitlement and other market contingency options, something that is contrary to Special Direction No. 10 to the BCUC."[15] The fact that it is easier to "ramp down" DSM than "ramp it up",[16] when combined with the implications for not achieving the expected DSM savings associated with BC Hydro's proposed DSM expenditures, suggests that BC Hydro should be pursuing cost effective Electric Load Avoidance DSM at this time, rather than waiting until closer to 2016.

B. Contribution of Residential Space and Water Heating Load to Load-Resource Gap

13. Electric space heating and water heating are notable contributors to BC Hydro's forecasted energy and capacity shortfall. The addition of new electric space and water heating customers, either in the form of new BC Hydro customers (i.e. new construction) or existing BC Hydro customers replacing their end-of-life gas appliances with electric appliances, will add incremental load.

(i) Differential Contribution to Energy and Capacity Requirements

14. Customers with electric space and water heating contribute disproportionately to BC Hydro's energy requirements relative to customers without electric space and water heating. Existing customers with non-electric space and water heating consume about 9,200 KWh/year, while customers with primary electric space and water heating systems use approximately 15,728 KWh/year, with a net difference of over 6,500/KWh per year.[17]

15. Space heating load has a significant seasonal aspect – it occurs primarily during the winter system peak – thus contributing disproportionately to BC Hydro's capacity

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15 Exhibit B-10, at 24.

16 Exhibit B-10, at 24. "It is easier to ramp DSM down than up. Ramping DSM down involves cancelling DSM programs or restricting eligibility criteria, which BC Hydro can do on its own; whereas ramping DSM up requires trade ally cooperation and action, which can be difficult or slow to secure."

17 Exhibit C13-7, at 20.

requirements.[18] This is illustrated by the graph from the 2007 BC Hydro Rate Design Application that has come to be known as the "Terasen Graph."[19] The "Terasen Graph" depicts BC Hydro as having a pronounced winter system peak in the months of November through February, with residential space heating load being the single greatest contributor to the winter system peak while all the other rate classes' loads are relatively flat.[20] Adding new electric space heating load will, all else equal, result in an increase in the system peak.[21] The peak will, in fact, become more pronounced. Exhibit B-73, filed after the close of the oral hearing, demonstrates that approximately 64% of incremental space heating load will fall in the months of November, December, January and February. Eighty-five percent of the incremental space heating load is encompassed if the six-month period of October to March is considered. Exhibit B-73 further indicates that approximately 55% of the incremental space heating load would be expected to fall in the Peak or Super-Peak periods.[22] The potential for new space and water heating load to make BC Hydro's system peak more pronounced was also illustrated in the hypothetical scenario where all residential space heating load migrates from other fuels to electricity by 2020, with more than half of the incremental 22,000 GWh/year occurring during Super-Peak or Peak periods.[23]

(ii) Potential Sources of New Space and Water Heating Load

16. There are two potential sources of new space and water heating load. First, new BC Hydro customers or developers may choose to install electric appliances. Second, existing BC Hydro customers who currently use another energy source for space and water heating may convert to electricity as their appliances reach end of life.

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[18] Exhibit B-73; Exhibit C13-7, at 11.

[19] Exhibit C13-7, at 11; see also Exhibit B-10, at 7, where BC Hydro stated that in mid-December 2008, its domestic system peak demand reached approximately 10,000 MW.

[20] Exhibit C13-7, at 18; Transcript, Vol. 6, at 877-878.

[21] Transcript, Vol. 6, at 878.

[22] Exhibit C13-7, at 43. The Peak and Super-Peak periods are the periods of high demand within the day when higher prices will be paid for supply based on Time-of-Delivery Factors in BC Hydro's Clean Power Call. The Time-of-Delivery Factors for electricity supplied in the Peak and Super-Peak periods are the highest in the winter months when most space heating occurs.

[23] Exhibit B-12, Response to Terasen IR 3.7.2 and Exhibit C13-7, at 43. The Terasen Utilities are citing this evidence to illustrate the seasonal nature of the load, not to suggest that this unlikely scenario will materialize.

Space and Water Heating Capture Rate (New BC Hydro Customers)

17. BC Hydro's load forecast assumes that, as new customers are added to the BC Hydro system, approximately 20% of new customers will install space heating and approximately 35% of new customers will install water heating, increasing to 21% and 38% respectively by the end of the 20 year forecast horizon.[24] These percentages of new customers that adopt particular end uses are referred to as "capture rates". BC Hydro's capture rates for space and water heating are extrapolated from BC Hydro billing data and reflect the current percentage of existing BC Hydro customers that have electric space heating and electric water heating (20% and 35% respectively).[25] The forecasted capture rates translate into over 5,500 new electric space heating customers per year over the forecast period and more than 8,600 new electric water heating customers per year.[26] The load associated with these additions compounds each year, and represents 12.8% of the forecast load growth between F2008 and F2027.[27] Looking at F2027 as a point in time the cumulative incremental annual space and water heating load attributable to customers captured between F2008 and F2027 is 1,933 GWh in F2027[28]. Of the 1,933 GWh, 1,409 GWh is for primary residential space heating, 483 GWh is for water heating and 41 GWh is for secondary space heating.[29]

18. BC Hydro's witnesses downplayed the importance to the overall load-resource gap of load associated with the capture of new space and water heating customers. Mr. Matheson implied, for example, that reducing the capture rate was of greater interest to the Terasen Utilities as natural gas utilities.[30] This view is at odds with BC Hydro's noted concern about the growing load-resource gap. The longer term nature of the investment made by customers in

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[24] Exhibit B-10, at 11-12.

[25] Exhibit B-10, at 11; see also Exhibit C13-7, at 30; Transcript, Vol. 6, at 887. BC Hydro agreed that the increase in the capture rate for space and water heating will be higher than 1% and 3% over the 20 year planning horizon because the 21% and 38% reflect the percentage of total residential stock in 2028.

[26] Exhibit B-4, Response to Terasen IR 2.5.4.

[27] Exhibit C13-8; Transcript, Vol. 6, at 881-882. BC Hydro accepted that all numbers contained in the Witness Aid were correct.

[28] The 1,933 GWh of incremental annual space and water heating load is also 25.8% of the forecast gap in F2027 between the Mid-Load Forecast after DSM and Existing and Committed Supply or 10.1% of the forecast gap in F2027 between the Mid-Load Forecast before DSM and Existing and Committed Supply (Exhibit B-10, Table 2-10).

[29] Exhibit C13-8.

[30] Transcript, Vol. 11, at 2039.

appliances means that there is a higher probability that the load will be avoided if another energy source is adopted upon installation as compared to encouraging the customer with DSM incentives to reduce his electricity consumption associated with the installed electric appliance. Moreover, BC Hydro intends to take measures to address lesser contributors to the forecasted load. For instance, the impact of space heating load during the 20 year forecast period is greater than the additional load being addressed by the proposed FNU3.[31] It represents close to the same amount of energy as the post-attrition Clean Call of 2,100 GWh.[32]

19. The evidence suggests that 1,933 GWh in F2027 may understate the amount of load contributed by residential space and water heating over the planning horizon. The capture rates of 20% and 35%, from which the above figure is calculated, are an extrapolation from billing data. BC Hydro is not confident that its billing data is accurate.[33] BC Hydro's 2006 Residential End Use Survey ("REUS") suggested that the percentage of existing BC Hydro customers that have electric space heating is in excess of 30%, not 20%.[34] The amount added annually for electric space heating based on a 20% capture rate is about 74 GWh.[35] A 50% increase in the electric space heating capture rate (up from 20% to 30%) would therefore add approximately a further 37 GWh/year. [Although Mr. Matheson suggested that increasing the capture rate by 50% (from 20% to 30%) would only increase the load by about 9 GWh/year[36], mathematically this cannot be the case. Mr. Matheson appears to have incorrectly performed his calculation based on a 10% increase rather than a 50% increase and BC Hydro accordingly uses a figure of 10% in its Submission.] The 50% increase in space heating capture would represent

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31 Exhibit B-10, at 5, shows the change over 20 years in Fort Nelson as close to 800GWh, or less than half the amount attributable to new space heating alone.

32 Transcript, Vol. 12, at 2208, lines 10-13.

33 Exhibit C13-7, at 23; Transcript, Vol. 6, at 889-890.

34 Exhibit C13-7, at 35-36; Transcript, Vol. 6, at 893-894.

35 Exhibit B-4, Terasen Utilities IR 2.5.1 (attached to the witness aid filed in Exhibit C13-8) and Terasen Utilities IR 2.5.4. The annual load increase of approximately 74 GWh/year attributable to new primary space heating customers can also be confirmed from the response to Terasen IR 2.5.4. For example, multiplying the new electric space heating customers for F2010 of 5,517 customer by the annual space heating load per new account of 13,412 kWh/customer = 74 GWh. The average annual load per new account in Table B of Terasen IR 2.5.4 was confirmed in the BC Hydro 2007 Rate Design hearing as being solely attributable to space and water heating.

36 Transcript, Vol. 11, at 2003. BC Hydro cited this evidence on page 61 of its Submissions.

additional annual load of approximately 705 GWh by F2027 (i.e., 50% of the 1409 GWh attributable to growth in primary electric space heating in F2027).[37]

Existing BC Hydro Customers Adopting Electric Space and Water Heating

20. In F2006, BC Hydro's residential customers consumed about 16,100 GWh[38], with space heating alone accounting for about 24% of that consumption.[39] That level of consumption is based on only a minority of BC Hydro's residential customers (20%-30%) having electric space heating. BC Hydro's load forecast, and the 12.8% or 1,933 GWh in F2027 cited above, assumes that none of the 70%-80%[40] of BC Hydro customers that currently have space heating appliances operated using another energy source will convert to an electric appliance during the next 20 years.[41] Given the age of the housing stock in BC, there are going to be households and businesses with gas heating systems that have reached end of life and require replacement. Some of these customers will convert to electric space and water heating if they continue to receive price signals based primarily on embedded costs, thereby further increasing the energy load and BC Hydro's supply requirements.[42]

(iii) Importance of Encouraging Efficient Choices among Energy Sources

21. Avoiding even a portion of the load associated with potential *new* customer captures of electric space and water heating will make a material contribution to closing the load-resource gap. Avoiding the potential for some of the 80% of *existing* customers to install electric appliances when their current non-electric appliances reach end-of-life will reduce the potential for exceeding the current load forecast. When other end uses for which energy source alternatives exist are included in the analysis, Electric Load Avoidance DSM takes on considerably more importance as a tool for BC Hydro to close the growing load-resource gap. Price signals that more closely reflect BC Hydro's marginal supply cost leave the customer free to make efficient choices for their particular circumstances.

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[37] Exhibit C13-8

[38] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 51.

[39] *Ibid*, at 52. Space heating share is much higher in electrically heated homes.

[40] The percentage of these customers depends on whether one uses 20% or 30% as the percentage of existing BC Hydro customers with electric space heating, per the billing data and REUS respectively.

[41] Transcript, Vol. 6, at 884-885.

[42] Transcript, Vol. 9, at 1483, where BC Hydro's witness agreed that BC Hydro's flat rates based on the embedded costs of supply were inadequate to encourage the efficient use of electricity.

III. THE ROLE OF ELECTRIC LOAD AVOIDANCE DSM IN SENDING EFFICIENT PRICE SIGNALS

22. Electric Load Avoidance DSM involves providing cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for end uses where electricity is not the most efficient energy source from a TRC perspective. The incentive payments mitigate the potential for the customer to choose an energy source based on (i) the prospect of paying electricity rates based to a significant extent on BC Hydro's embedded cost of supply, or (ii) any differential in capital cost between electric appliances and appliances using another energy source.[43] Structuring Electric Load Avoidance DSM programs is a matter for future work; but, incentives can be based, for instance, on energy saved, square footage (for space heating), volume (for water heating), or the incremental capital cost of adopting an alternative energy source.[44] Electric Load Avoidance DSM encourages the customer not to adopt electricity, but is neutral in that it leaves the customer free to make the choice as to the appropriate energy source for a particular application based on a more efficient price signal. The right energy source for a particular customer, for a particular application, in the customer's particular circumstances might be electricity, natural gas, or some other energy source.[45]

23. BC Hydro customers pay rates primarily reflecting embedded costs, and are insulated from BC Hydro's true marginal cost of supply. The BC Hydro RIB rate improves the conservation price signals experienced by residential customers; however, there is still room for improved conservation signals as, by its design, many customers see mainly the Step 1 rate. The Step 2 rate changes lag behind BC Hydro's marginal cost of supply. BCUC Order No. G-124-08 and the RIB Decision set the residential Step-2 rate at 8.27 cents per kWh (equal to $82.70 per

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[43] Transcript, Vol. 9, at 1509.

[44] BC Hydro has used similar approaches in the context of its load reduction DSM in the LTAP. See B-1, Appendix K, Sub-Appendix F, Program Summaries.

[45] BC Hydro discounted the potential for other fuel source alternatives to gain a foothold. See, e.g., Transcript Vol. 11, at 1999-2000 where BC Hydro's witness stated that "[w]e're certainly see a lot of additional interest in heat pumps currently, but I think they still represent a fairly small -- a small percentage, and I think there's some uncertainty in terms of how it's going to unfold moving forward". However, it is also necessary to consider the fact that this may reflect the current inefficient pricing of electricity from a TRC perspective as a competing energy source.

MWh) effective April 1, 2009.[46] This is well below the expected marginal supply cost identified in the LTAP proceeding of $120 per MWh. For those customers who mainly see the Step 1-rate, it is below the previous flat rate because it is set residually.

24. Relative differences in the capital cost associated with adopting a particular energy source can also represent an impediment to efficient choices regarding energy source. To illustrate, a customer faced with installing a new heating appliance might currently be expected to choose electric space heating in the absence of the right pricing signals or incentives,[47] as an electric plenum or baseboard heaters may appear to the customer to be cheaper than adopting a higher efficiency natural gas furnace, or adopting another type of technology such as heat pumps or geo-exchange systems.

25. It is important to send the appropriate price signals and messaging to customers and developers at the time the choice of energy source is made, because once the choice is made and the customer has invested in appliances it represents an obstacle to later changing to a different energy source. As BC Hydro agreed, a new house "built without ductwork and with baseboard heating... [has] an obstacle for inputting either a natural gas furnace or a heating [sic] pump in the future."[48] BC Hydro's Submissions expanded on this point:

> A customer's choice at the moment of installing space and water heating is a long term selection. Once made, it is difficult (expensive) to reverse. The appliances have useful lives of approximately 20 years and the building structures, and internal infrastructure would be much longer. Such choices are not minute to minute or day to day or year to year decisions. They are relatively permanent and have short, medium and long-term consequences.

Although BC Hydro was intending by the above submission to urge caution in pursuing Electric Load Avoidance DSM, the passage speaks much more strongly to the Terasen Utilities' point

[46] The Commission's Decision in the RIB Application included it its design principles parameters as to when BC Hydro must come forward with a proposal to change its cost of new supply and how to phase in the change. See for instance, In re BC Hydro, Residential Inclining Block Rate Application, Reasons for Decision (September 24, 2008), at 108.

[47] Transcript, Vol. 9, at 1503-1505; see also Transcript, Vol. 11, at 2000-2001

[48] Transcript, Vol. 11, at 2001. When responding to the question of whether a new house built without ductwork and with baseboard heating would have "an obstacle for inputting either a natural gas furnace or a heating pump in the future," Mr. Hobson stated that "Depending on the type of home it is, it'll create some limitations, yes."

that these customers who are faced with a decision as to appliances using different energy sources should be the primary targets of Electric Load Avoidance DSM.

26. BC Hydro should pursue cost-effective Electric Load Avoidance DSM in tandem with its proposed portfolio of load reduction DSM. It is not in the best interest of customers for BC Hydro to wait passively for customers to adopt electrical appliances where it does not make sense from a TRC perspective, in full anticipation of spending *load reduction* DSM dollars to avoid high marginal supply costs associated with serving that added load. Load reduction and load avoidance have the same value to BC Hydro customers in terms of BC Hydro avoiding new high cost supply; however, successful load avoidance provides additional certainty that new supply will not be required over the long useful life of the adopted non-electric appliances.[49] As discussed later in these Submissions, BC Hydro and the Terasen Utilities agree that the installation of a particular type of appliance is a barrier to changing energy source during the life of the appliance. BC Hydro can target its load reduction DSM dollars to customers who have chosen electricity as an energy source based on more efficient price signals from a utility resource cost (i.e. TRC) perspective. Puget Sound Energy and Avista are examples of other utilities that use incentive programs to address the fact that their rates structures would otherwise tend to encourage adoption of electricity where more efficient fuel choices are available.[50]

IV. BENEFIT TO BC HYDRO CUSTOMERS ASSOCIATED WITH ELECTRIC LOAD AVOIDANCE DSM

27. Government has indicated its objective is "to encourage public utilities to pursue demand-side measures", and the UCA requires BC Hydro to provide an explanation in the LTAP as to why cost-effective DSM is not being pursued.[51] The Commission's overarching responsibility is to ensure that rates are just and reasonable.[52] In light of these requirements, the starting place for the Commission's analysis of Electric Load Avoidance DSM must be its

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[49] Transcript, Vol. 11, at 1996-1997.

[50] Transcript, Vol. 9, at 1518. Puget Sound Energy offers one-time incentives to eligible customers to help defray the cost of conversion to highly efficient natural gas space heating and/or domestic water heating. The incentive program is structured as a rebate to customers based on type of existing electric heating to be replaced and the amount of historic energy usage (see Exhibit C13-9, at 6). Avista offers similar home improvement incentives for space heating conversion from electric to natural gas or air/ground source heat pump (see Exhibit C13-9, at 17).

[51] UCA, s. 44.1(2) (b), (f).

[52] UCA, ss. 59 - 61.

impact on the rates paid by BC Hydro customers.[53] This Part of the submissions address the following points:

(i) The legislative scheme in the UCA requiring public utilities to look first to cost-effective demand-side measures is realized by BC Hydro pursuing Electric Load Avoidance DSM identified as having a TRC ratio of benefits to costs of more than one.

(ii) The 2007 CPR identified significant *economic potential* (determined on a TRC basis) for Electric Load Avoidance DSM. From an overall resource cost (i.e. TRC) perspective, BC Hydro customers collectively stand to benefit from the pursuit of this *economic potential*.

(iii) The *economic potential* for Electric Load Avoidance DSM will likely be higher today than in the 2007 CPR based on a much higher avoided cost of new electricity supply.

(iv) In light of the cost implications for all BC Hydro customers, Electric Load Avoidance DSM exhibiting a favourable TRC should not be eliminated from contention by means of a simple payback analysis based on current rates paid by customers that reflect, to a significant extent, embedded costs.

A. Cost-Effectiveness Determined By TRC Analysis

28. The cost-effectiveness of Electric Load Avoidance DSM is determined with reference to a TRC analysis, which focuses on the resource costs and benefits of electricity and a fuel alternative.

29. BC Hydro customers as a whole will benefit from BC Hydro making available the necessary cost-effective Electric Load Avoidance DSM to avoid load that would otherwise have to be served at BC Hydro's marginal cost of new supply. Electric Load Avoidance DSM with a TRC of more than one (identified in BC Hydro's CPR as having *economic potential*) that is not pursued represents a lost opportunity to manage resource costs for the benefit of all BC Hydro customers. BC Hydro rates will experience greater upward pressure than would be the case (all

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[53] BC Hydro stated in its Submissions at 19 line 18 to 11 that "it is the interests of its existing and future customers that are paramount, especially when compared to, say, another intervening utility, which has obvious commercial interests." The Terasen Utilities agree that the Commission should base its findings regarding Electric Load Avoidance DSM on the interests of BC Hydro's customers. The evidence is that Electric Load Avoidance DSM <u>is</u> in the interests of BC Hydro customers. Whether or not the commercial interests of the Terasen Utilities are aligned with the interests of BC Hydro customers is irrelevant.

else equal) if the targeted load is reduced or avoided by the adoption of other alternative energy sources including natural gas.[54]

30. Using the TRC test to assess the cost-effectiveness of Electric Load Avoidance DSM is consistent with the DSM Regulation. The Regulation references TRC as a measure to determine cost-effectiveness in respect of particular DSM programs and requires the Commission to use BC Hydro's avoided cost of supply for assessing the cost-effectiveness of measures taken by entities that receive service from BC Hydro.[55] In the Commission's recent decision on TGI and TGVI's Energy Efficiency and Conservation ("EEC") Application, the Commission endorsed the use of the TRC test more generally.[56]

B. Economic Potential Identified in 2007 CPR

31. The section of the CPR addressing Electric Load Avoidance DSM considered only natural gas as a fuel alternative to electricity for particular end uses, and referred to the measures examined as "fuel switching" measures. Opportunities clearly exist for BC Hydro to explore Electric Load Avoidance DSM involving other alternative energy sources apart from natural gas, and it would be appropriate for all energy source alternatives to be considered in future analysis of Electric Load Avoidance DSM.

32. The CPR identified whether measures had *economic potential*, defined by a TRC of greater than one.[57] Notably, the CPR equated this *economic potential* with "cost-effective" Electric Load Avoidance DSM,[58] which is appropriate. In the context of the Electric Load

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[54] Transcript, Vol. 9, at 1523.

[55] For instance, the DSM Regulation provides for the use of TRC for the low-income programs. Section 4(2) allows the use of avoided cost, rather than the purchase price, as the measure for benefit, when assessing cost effective of a DSM of a bulk electricity purchaser. Additionally, section 4(4) specifies that the Commission cannot reject DSM based on a ratepayer impact measure test.

[56] In Re Terasen Gas Inc. and Terasen (Vancouver Island) Inc., Energy Efficiency And Conservation Application, Decision (April 16, 2009) ("EEC Decision"), at 34: "The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such."

[57] Exhibit B-1-1, Appendix K, CPR Summary Report, at 15; see also Exhibit B-4, Response to BCUC IR 2.201.5, 2.206.1.

[58] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 109. The CPR states "[i]n this study, 'cost-effective' means that the fuel-switching measure passes the Measure Total Resource Cost (TRC) test."

Avoidance DSM examined in the CPR, the TRC analysis considered the resource costs of both electricity and the alternative energy source (natural gas, in this case). TRC was defined in the CPR as "the net present value of energy savings that result from an investment in a fuel-switching measure." It is equal to "its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating costs."[59] The CPR used BC Hydro's avoided cost of electricity ($88/MWh based on the results of the F2006 Open Call for Power[60]) to determine any applicable changes in operation costs.[61] In simple terms, the measures identified as having *economic potential,* i.e. a TRC Benefit/Cost ratio of greater than one, have the potential to provide a net benefit to BC Hydro customers as a whole based on BC Hydro's avoided supply costs.

33. The CPR identified significant *economic potential* for Electric Load Avoidance DSM that uses natural gas as an alternative fuel in the residential, commercial and industrial sectors.[62] The *economic potential* of Electric Load Avoidance DSM in the BC Hydro CPR was found to be 24.02 PJ equivalent (6,674 GWh/year) by 2026 in the current gas supply cost scenario, and 11.85 PJ equivalent (3,293 GWh/year) by 2026 in the high gas supply cost scenario.[63] BC Hydro's 2007 CPR concluded that

> [u]nder the Current supply cost forecast, there are a number of fuel-switching measures . . . that have a positive Measure TRC [i.e. TRC for the measure expressed in dollars is positive] and a Measure Benefit/Cost ratio that is equal to, or greater than one. This result suggests that from a provincial economic perspective, there are opportunities where switching from electricity to natural gas may be beneficial.[64]

C. Increase in BC Hydro's Avoided Cost of Supply Increases Economic Potential

34. BC Hydro's avoided cost of supply is a key input in the determination of *economic potential*, and the avoided cost of supply has increased markedly since the 2007 CPR

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59 Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 21.

60 Exhibit B-1-1, Appendix K, Summary Report, at 15.

61 Exhibit B-1-1, Appendix K, Summary Report, at 53.

62 Exhibit B-1, Response to BCSEA IR 2.28.1, Attachment 1 at 6.

63 Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 111 (current natural gas supply cost scenario); at 115 (high natural gas supply cost scenario).

64 Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108.

was conducted.[65] All else equal, the *economic potential* increases with the increases to BC Hydro's avoided cost of supply.

35. The *economic potential* in the 2007 CPR was identified using an avoided cost of supply of $88/MWh, based on an average of the results of the F2006 Open Call for Power.[66] BC Hydro's Evidentiary Update identified an avoided supply cost of $120/MWh (F2006 dollars) for the purposes of assessing DSM portfolios.[67] This represents a proxy for the expected average bid price in the current Clean Power Call.[68] The $120/MWh avoided cost of supply does not include distribution costs or line losses for distribution,[69] which would also be incurred when delivering non-avoided electricity to end use customers. The distribution line losses alone add an additional four percent to the delivered cost of energy.[70]

36. The $120/MWh avoided supply cost also does not account for the fact that space heating load occurs in winter months when electricity is the most expensive.[71] As an example, a single customer with 4,260 kWh of space heating load would consume more than over 3,000 MWh from November to March.[72] The cost of serving space heating load, even before factoring in line losses, is likely closer to $130/MWh[73] using the most recent weighted average time of delivery percentage of 108% provided by BC Hydro.[74]

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65 Transcript, Vol. 9, at 1522.

66 Exhibit B-1-1, Appendix K, CPR Summary Report, at 15. Exhibit C13-12 and Transcript 11, at 2020-2021 evidence the Terasen Utilities' objections to the CPR. In calculating the TRC of electricity-to-gas "fuel switching" measures, BC Hydro used both a current and high gas forecast. However, it only employed the current forecast on the electricity side, which was then $88/MWh. The result of considering a high gas cost scenario without accounting for upward pressure in marginal electricity supply costs was to reduce the amount of economic potential. The Terasen Utilities registered its objections to this approach during the stakeholder process in the CPR.

67 Exhibit B-10, at 25; Transcript, Vol. 9, at 1528.

68 Transcript, Vol. 9, at 1522.

69 Transcript, Vol. 9, at 1529-1530

70 Exhibit B-12, Response to Terasen IR 3.7.1.

71 See Transcript, Vol. 6, at 915-918, for an explanation of the correlation between peak months and energy prices.

72 Exhibit B-73, BC Hydro Undertaking No. 10.

73 $120/GWh x 1.08 = $129.6/GWh

74 Exhibit B-73, BC Hydro Undertaking No. 10. The undertaking response filed by BC Hydro as Exhibit B-73 was based on the time of delivery pricing from the 2009 Call for Tenders webpage. (Exhibit C13-7, at 43). The undertaking response corrected an error in BC Hydro's response to Terasen Utilities IR 3.7.3 (Exhibit C13-7, at 42), in which BC Hydro had accounted for the consumption of electric space heating customers for all end uses rather than just space heating. See also Transcript, Vol. 6, at 913.

37. Natural gas cost is a component of the TRC analysis for Electric Load Avoidance DSM examined within the CPR. The Terasen Gas combined commodity cost and midstream charge based on service to the Lower Mainland was $8.551 per GJ at the time of the hearing, well within the scenarios examined in the CPR, and within the BC Hydro long-term natural gas price forecast.[75] The carbon tax would have to be added to this value, but as $8.551 per GJ is less than one third the cost of BC Hydro's avoided cost of supply there is a significant margin to allow for this and yet still yield a favourable TRC. $120/MWh corresponds to an equivalent gas cost of $30.00 per GJ.[76]

38. The significant increase in the avoided cost of new electricity supply from the $88/MWh used in the 2007 CPR, combined with the fact that the current gas cost forecast remains within the scenarios employed in the 2007 CPR, indicates growing opportunities for BC Hydro to address a portion of the load-resource gap with cost-effective Electric Load Avoidance DSM.

D. Customer Payback Calculated Based on Embedded Cost Rates

39. The CPR did not identify any *achievable potential* for the Electric Load Avoidance DSM considered[77] because customers paying rates that reflect the low embedded cost of electricity do not see the "payback" necessary from these measures to consider adopting another energy source.[78] The Terasen Utilities, which were involved in the CPR stakeholder process, have consistently expressed concerns about eliminating measures based on payback established with reference to rates based to a significant extent on embedded costs.[79] The embedded cost of electricity does not produce effective price signals for conservation, a fact

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[75] Exhibit B-1, at 4-16, Figure 4-2.

[76] Exhibit C13-11; Exhibit B-33.

[77] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108 and footnote 65..

[78] Exhibit B-1-1, Appendix K, BC Hydro CPR 2007, Summary Report, at 55. The simple payback, according to the CPR, is "a measure of the length of time required for cumulative savings from a project to recover its initial investment cost and other secured costs, without taking into account of the time value of money." Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1,at 21-22. See also Exhibit C13-5, at 38, where the excerpt from the CPR states: "This somewhat contradictory result (i.e. measure passes the economic screen but has excessively long payback period) is explained by the large discrepancy between the wholesale and retail prices for natural gas and electricity."

[79] Exhibit C13-12, at 23; Transcript, Vol. 11, at 2020-2021.

which BC Hydro recognized in adopting the RIB rate structure.[80] BC Hydro has a responsibility to its customers to identify incentive models to turn the identified *economic potential* into *achievable potential.*

E. Summary

40. A proactive approach by BC Hydro to developing appropriate Electric Load Avoidance DSM incentives will help to ensure that customer choices are not made based on inefficient price signals to the detriment of customers as a whole. The significant increase in the avoided cost of supply from the $88/MWh used in the 2007 CPR provides greater opportunities for BC Hydro to use Electric Load Avoidance DSM to address a portion of the load-resource gap.

V. REGIONAL REDUCTION IN GREENHOUSE GAS EMISSIONS

41. BC Hydro's objection to Electric Load Avoidance DSM is rooted in the assumption that natural gas is the logical alternative energy source for particular end uses, discounting the potential for British Columbians to adopt other alternative energy sources that have the potential to attract a larger market share with efficient pricing of electricity. The Terasen Utilities agree that natural gas can provide appropriate energy solutions and could be the right choice for some customers. However, the potential for natural gas consumption in direct use applications within BC to reduce GHG emissions on a regional basis, combined with the obligation on British Columbians to pay the carbon tax on domestic natural gas consumption, eliminates BC Hydro's primary policy basis for opposing natural gas as part of Electric Load Avoidance DSM. In this part we make the following points.

(i) There are three equally compelling reasons why Electric Load Avoidance DSM involving natural gas can, on a regional basis, "reduce greenhouse gas emissions" as contemplated in "government's energy objectives". They are:

(A) First, the use of natural gas or alternatives for specific end uses in British Columbia will make additional hydroelectricity available

[80] In re BC Hydro, Residential Inclining Block Rate Application, Reasons for Decision (September 24, 2008), at 50, 95, 107. Dr. Orans also noted in the RIB Application proceedings that to assess the RIB as a mechanism to encourage conservation, BC Hydro "should be probably looking at a total resource cost perspective and looking at the choices customers have and the choices that BC Hydro has for meeting a new supply." (Exhibit C13-9, at 3). BC Hydro should similarly be approaching Electric Load Avoidance DSM from a TRC perspective.

for export to displace coal or gas-fired generation on the margin in the Western Interconnection.

(B) Second, Electric Load Avoidance DSM reduces the need for BC Hydro to import electricity that is frequently generated through the relatively inefficient consumption of gas or coal.

(C) Third, natural gas will be consumed at a higher efficiency, with a lower emission factor, in end-use appliances than if it is exported for use in generating electricity.

(ii) Efficient pricing of natural gas is achieved in part by requiring domestic consumers to pay the carbon tax or (in BC Hydro's case after 2016) acquiring offsets. The focus in this proceeding should be on achieving the right pricing for electricity, which will permit energy consumers to arrive at the optimal balance among alternative energy sources.

42. Electric Load Avoidance DSM represents a means of reducing (all else equal) electricity rates for all customers while remaining aligned with government's interest in mitigating climate change through the right pricing of energy sources.

A. Electricity Exports Displace Coal and Gas Fired Generation on the Margin

43. The Commission has concluded twice previously that exporting surplus electricity achieved by using a more efficient resource alternative in British Columbia will displace coal or gas-fired generation at the margin in the Western Interconnection. The evidence in this proceeding continues to support those determinations.

(i) Previous Commission Decisions

44. In the Commission's October 26, 2007 Decision on BC Hydro's 2007 Rate Design – Phase 1, the Commission stated:

> Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro's service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. <u>The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space</u>

> <u>and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest</u> [Emphasis added].[81]

45. The Commission repeated in December 2007 that it "continues to agree with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in BC will make additional energy available to displace coal."[82]

46. In the Commission's recent decision on the Terasen Utilities' EEC Application, the Commission found "that the 'optimal balance' as between natural gas and electricity has not been established" on the evidentiary record in that Application and "that the efficiency of other energy sources over and above that of electricity has not been adequately established."[83] The EEC Panel determined that there was insufficient evidence on the record to conclude that "a regional approach should be adopted as a justification for EEC expenditures aimed at substituting natural gas as a fuel to replace electricity."[84] The evidentiary record in this proceeding, unlike the EEC Application, contains voluminous evidence with respect to the relative efficiency of electricity and gas, and the benefit to BC Hydro customers associated with Electric Load Avoidance DSM. BC Hydro's CPR considered, in a TRC analysis, the benefits and costs of particular measures in light of the resource costs of both electricity and the alternative energy source.[85] The *economic potential* for particular Electric Load Avoidance DSM is quantified, and the positive impact on BC Hydro customers in the form of reduced rates (all else equal) is clear. The CPR concluded that "This result suggests that from a provincial economic perspective, there are opportunities where switching from electricity to natural gas may be beneficial."[86] The measures envisioned in the CPR do not require any determination to be made, either by BC Hydro or the Commission as to the "optimal balance" among energy sources. Rather, by putting in place appropriate price signals, British Columbians will make appropriate choices based on their own requirements. The evidence in this proceeding as to BC Hydro's

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[81] In re British Columbia Hydro and Power Authority 2007 Rate Design Application – Phase 1, Decision (October 26, 2007), at 191.

[82] In re Terasen Gas (Vancouver Island) Inc. and Terasen Gas Inc., System Extension And Customer Connection Policies Review, Decisions (December 6, 2007), at 50.

[83] EEC Decision, at.17.

[84] EEC Decision, at18.

[85] See, e.g., Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 90-108.

[86] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108.

approach to purchasing offsets outside BC in order to reduce the cost of those offsets for BC Hydro customers (discussed below) also supports the regional approach to considering GHGs.

(ii) Evidence in this Proceeding

47. The evidence in this proceeding supporting the conclusion that the use of an alternative energy choice for applications such as space and water heating in BC will make additional energy available to displace gas and coal-fired generation is summarized below. The evidence comes from documents on the record, BC Hydro's written evidence (i.e. Application and IR responses), and the cross-examination of BC Hydro witnesses. As such, it was unnecessary for the Terasen Utilities to call evidence in this regard.

48. Renewable power generated in British Columbia that is surplus to the domestic load requirements in any one time period will be exported into the Western Interconnection.[87] In the vast majority of the time (over 80%), the marginal source of electricity supply in the Western Interconnection is generated from natural gas-fired or coal-fired generation facilities.[88] During such times, the injection of BC renewable power in to the Western Interconnection will displace existing or new gas or coal-fired generation.[89] As the Global Energy report included with the LTAP stated, "the renewables will run to meet the load, thereby displacing natural gas-fired generation that would otherwise be needed to meet loads…. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal-fired generation rather than natural gas-fired generation….".[90]

49. The pursuit of cost-effective Electric Load Avoidance DSM will result in reduced electric load in BC. The Terasen Utilities submit that this also logically will lead to BC

[87] Exhibit B-3, Response to Terasen IR 1.2.2, 1.2.6.

[88] Exhibit B-3, Response to Terasen IR 1.2.6.. When asked whether in the Western Interconnection, either natural gas-fired or coal-fired generation would be on the margin more than eighty percent of the time, BC Hydro responded that this is "generally" true. (See Exhibit B-4, Response to Terasen IR 2.4.2).

[89] Exhibit B-3, Response to Terasen IR 1.2.6; see also Transcript, Vol. 3, at 271-272.

[90] Exhibit B-1-1, Appendix H, at 11-12. In Exhibit B-3, Response to Terasen IR 1.2.6, BC essentially confirmed the cited statement by stating "adding any resource into the WECC grid, be it renewable or non-renewable, will displace the marginal unit if the resource that is being added has a lower variable operating cost than the marginal unit." As described later in these submissions, this same displacement occurs with natural gas produced in British Columbia. The combined emissions factor associated with the production of BC natural gas and its consumption in either direct use applications or an efficient CCGT is well below the emissions factor attributed to BC Hydro's imports in 2006. Therefore, the use of BC's natural gas in the WECC region results in a GHG benefit. (Citations provided below.)

renewable power that would otherwise serve BC load being available for export (the evidence supporting this logic and BC Hydro's argument to the contrary is addressed below). These exports associated with Electric Load Avoidance DSM will reduce GHGs in the region even where BC Hydro customers have chosen natural gas as the alternative fuel because of the difference in combustion efficiency between domestic gas appliances and gas and coal-fired generation that is displaced by the clean power made available for export. Combustion efficiency is important in terms of lowering GHG emission.[91] A modern combined-cycle gas-fired generator (CCGT) operates at about 50% efficiency, and the efficiency rate of a coal-fired generator is even lower.[92] In contrast, modern domestic gas furnaces and hot water heaters operate at much higher efficiency – typically between 85 percent and 95 percent efficiency.[93] The emissions factor for furnaces is 200 tonnes / GWh[94], the emissions factor for a CCGT operating at 50% efficiency is 360 tonnes / GWh and BC Hydro's imports are assigned an emissions factor of 550 tonnes/ GWh.[95]

50. BC Hydro witnesses conceded that during the two-year LTAP period, if more customers choose direct use of natural gas for heating applications, particularly for spacing heating, there will be "more electricity available for export from British Columbia."[96] BC Hydro's evidence and its submissions regarding its own planning response to reduced load in the medium to long term[97] do not speak to the potential for IPPs to build in excess of BC Hydro's load requirements and export the surplus power. BC Hydro confirmed that it was not the only potential purchaser for renewable power generated in BC over the medium to long-term, and that

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[91] Transcript, Vol. 12, at 2171-2173.

[92] Exhibit B-3, Response to Terasen IR 1.2.5.

[93] Transcript, Vol. 11, at 2039-2040. BC Hydro witnesses agreed that a modern space heater operated on natural gas is rated as generally between 85 and 95 percent efficiency. See also Exhibit C13-9, at 11, 14. According to Puget Sound, direct use of natural gas to fire a home furnace would make use of 80% of the original energy content of the gas as heat for the home. Avista is using a 90% efficiency rate.

[94] CPR, Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at page 121, notes that the GHG emission intensity factor for natural gas is 180 tonnes/GWh for direct use of natural gas. However, this appears to correspond to 100% efficiency. 90% efficiency, by our calculations, is closer to 200 tonnes per GWh, so we have used this amount in these Submissions.

[95] Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at.121. Also, it is clear that emissions levels in the WECC regional will remain at this level for some time, as estimated average performance standard in Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, and Wyoming. A performance standard is the GHG emissions level above which **offsets** must be acquired. (Exhibit B-1, at 4-20, lines 14-21).

[96] Transcript, Vol. 6, at 824.

[97] Exhibit B-4, Response to BCSEA IR 2.29.2.

neither law nor policy precludes IPPs from continuing to build for direct export.[98] The provincial government is contemplating an export market for BC power. Former Minister Richard Neufeld said in a CBC interview on the subject of IPP power: "We have huge opportunities in this province to build generation for export, also, between jurisdictions south of us that generate with coal."[99] A transmission line from Canada to Northern California is currently under consideration to capitalize on such potential clean power export.[100] The Terms of Reference for the Commission's pending Section 5 Inquiry similarly contemplate pursuing the Province's potential for exporting clean, renewable energy.[101] The Terms of Reference also state that when making assessment of generation resource development, the Commission should consider that "other jurisdiction will continue to pursue the reduction of greenhouse gas emission…".[102] The Climate Action Team recommended building for surplus for export.[103] Additional evidence regarding the demand for BC renewables is referenced by BC Hydro on pages 68 and 69 of its Submissions.

51. This same approach is evident in the decision of the Manitoba Public Utilities Board with respect to the effect of exporting clean power, which was referred to during the hearing.[104]

52. BC Hydro relies in its argument[105] upon Dr. Jaccard's evidence regarding the need to move to electrification of space and water heating in order to make a significant impact in climate change. Dr. Jaccard's analysis is premised on the very long-term horizon when there is no longer gas and coal-fired generation on the margin in the Western Interconnection that can be displaced by the high-efficiency direct consumption of natural gas in domestic and commercial applications in British Columbia. Jurisdictions within the Western Interconnection have made significant investments in gas and coal-fired generation (they account for 58% of the energy

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[98] Transcript, Vol. 3 at 297-298.

[99] Exhibit C13-5, at 70; Transcript, Vol. 3, at 298-299.

[100] Exhibit C13-5, at 68.

[101] Terms of Reference (available at http://www.bcuc.com/sectionfiveinquiry.aspx). One of the recitals is: "Whereas the 2007 Speech from the Throne stated: Government will pursue British Columbia's potential as a net exporter of clean, renewable energy."

[102] Terms of Reference, Section 6 (b) (vi).

[103] BC Hydro Submissions, at 55. See Item 15.

[104] Transcript, Vol.6, at 811 to 814.

[105] BC Hydro Submissions, at 56.

generation),[106] and it will be decades before these are displaced by a cleaner domestic resource. Notably, California, Washington and Oregon have used a CCGT operating at 50% efficiency level as their performance standard for clean electricity.[107]

53. BC Hydro has made an unjustified leap in logic in assuming that exports from BC will only displace higher cost renewables. In the Western Interconnection, gas and coal-fired generation collectively represent about 58% of the energy generation, and are on the margin over 80% of the time.[108] Renewables currently represent approximately 6% of energy generation in the WECC.[109] Appendix H of the LTAP Application, Global Energy's Renewable Energy Market Analysis Report, contemplates that introducing renewable power into supply resources of the Western Interconnection will displace gas-fired and coal-fired generation. For instance, the Report states:

> Global Energy is also aware that the WCI is reviewing studies done by the California Energy Commission (CEC) that show amounts of GHG reductions in each Western state under different penetrations of energy efficiency and renewables.
>
> The CEC studies discussed in the above paragraph were performed by running hourly simulations of the WECC power grid, with hourly loads across WECC being served by economic dispatch of generation available in the region. In its "current conditions extended into the future" case, the CEC studies demonstrate the reality that much load in WECC is served by natural gas-fired generation. As the CEC increased penetration of renewables in the future in its alternative views of the future, the renewables will run to the meet the load, thereby displacing natural gas-fired generation that would otherwise be needed to meet loads. The CEC ran a few sensitivities with high GHG taxes in place. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal-fired generation rather than natural gas-fired generation because coal generation emits about twice the amount of GHG/kWh than does natural gas-fired generation. The CEC concludes that a good way to reduce GHG is to reduce thermal generation levels by causing higher penetrations of energy efficiency and renewable power supplies.[110]

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[106] Exhibit B-3, Response to Terasen IR 1.2.3; 2.4.2.

[107] Exhibit B-1, at 4-20, lines 4-10. This means that GHGs are offset to the level of a 50% efficient CCGT only, which implicitly means that gas-fired generation will continue to play a role in the WECC region to displace coal-fired generation on the margin.

[108] Exhibit B-3, Response to Terasen IR 1.2.3; 2.4.2.

[109] Exhibit B-3, Response to Terasen IR 1.2.3

[110] Exhibit B-1-1 Appendix H, at 11 and 12.

54. Also, fulfilling RPS targets is not the only reason that parties from U.S. jurisdictions may seek to acquire green power from BC. Mr. Youngman noted, for instance, the potential for significant changes under the Obama Administration in the areas of cap and trade and more aggressive climate change policies and legislation.[111] This suggests that changes imposed at the U.S. federal level could begin to overtake the RPS requirements imposed at the state level. It is clear, however, that if BC's renewable electricity is consumed for space and water heating in BC, then it will not be available to reduce the heavy reliance on fossil fuel-based electricity generation in other jurisdictions.

55. Based on the evidence discussed above, the Commission should reject BC Hydro's argument on page 68 of its Submissions that the premise of regional impacts "can only be derived by two events simultaneously occurring: (1) BC Hydro having surplus it did not plan for as a result of fuel switching or BC Hydro building for export; and (2) No U.S. entity wanting to acquire BC Hydro's clean or renewable energy to fill that entity's RPS targets."

B. Avoidance of Imports of Electricity Generated from Coal and Natural Gas

56. BC Hydro is a net importer of electricity in most years.[112] More than 50% of BC Hydro's imports come from low-efficiency gas-fired and coal-fired generators elsewhere in the Western Interconnection.[113] BC Hydro's reliance on these imports would decrease as load requirements associated with, for instance, space and water heating decreased. According to BC Hydro's 2007 CPR, a GHG factor of 550 tonnes per GWh was assigned for BC Hydro's electricity generation based on actual values for imported electricity in F2006, whereas the Greenhouse Gas Emission Factor for a high efficiency furnace is 200 tonnes/GWh.[114] Thus, there is a clear GHG reduction advantage to using natural gas in direct end use applications to reduce BC Hydro's requirements to import electricity produced by gas or coal-fired generation. BC Hydro has acknowledged this environmental benefit in previous proceedings: "In the past

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[111] Transcript, Vol.9, at 1583 to 1585.

[112] Transcript, Vol. 3, at 270; Transcript, Vol. 6, at 814.

[113] Transcript, Vol. 3, at 271; Exhibit C13-5, at 40.

[114] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 121. As indicated in a later footnote, the 200 tonnes/GWh figure was derived from evidence that suggests natural gas at 100% efficiency produces 180 tonnes/GWh. The Terasen Utilities recalculated this based on 90% efficiency.

BC Hydro encouraged customers to use natural gas instead of electricity for space heating, based on economic <u>and environmental</u> considerations." [Emphasis added.][115]

57. Self-sufficiency is a "red herring" in this analysis. BC Hydro will remain a net importer until it achieves self-sufficiency,[116] but will continue to import power after 2016 as self-sufficiency is determined on an annual net basis.[117] From the perspective of GHG emissions, the relevant consideration is what resource is on the margin in the Western Interconnection at the time of the imports. Where imports occur during the peak winter months, space heating load can be expected to drive a disproportionate amount of the imports of electricity generated from the combustion of gas and coal.

C. Natural Gas is Consumed at Higher Efficiency

58. The combustion efficiency of natural gas is important in terms of lowering GHG emission, irrespective of the status of British Columbia's (or BC Hydro's) electricity imports / exports.[118] From a GHG perspective, consuming natural gas in domestic appliances at 80%-95% efficiency is preferable to using it in gas-fired generation at less than 50% efficiency. Whereas the emissions factor for furnaces is 200 tonnes / GWh, the emissions factor for a CCGT operating at 50% efficiency is almost double that amount (360 tonnes / GWh).[119] Natural gas production has a strong future in British Columbia. The Energy Plan, for instance, expresses government's intent to "take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas section in British Columbia."[120] The provincial budget and fiscal plan for 2009/10 – 2011/12 shows Government's continuing support for the expansion of British

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[115] Exhibit B-3, Response to Terasen IR 1.3.1.

[116] Transcript, Vol. 3, at 270-271.

[117] Special Direction 10, s.3

[118] Transcript, Vol. 12, at 2171-2173..

[119] See Exhibit C13-5, at 75 (rebate according to efficiency rate). Exporting natural gas for consumption in a gas-fired generator could still reduce GHG's in the Western Interconnection, although to a lesser extent that if it is consumed in domestic applications, if it displaces coal-fired generation. According to BC Hydro's 2007 CPR, Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 121, the GHG emission intensity factor for natural gas combustion is 180 tonnes/GWh (it appears this assumes 100% efficiency). Thus, the emissions factor for natural gas consumption at 50% efficiency is 360 tonnes/GWh, which is better than the emissions factor assigned to BC Hydro's imports in 2006 of 550 tonnes / GWh.

[120] Exhibit C13-5, at 64.

Columbia's "abundant natural gas resources."[121] The same logic that favours the consumption of natural gas in high efficiency appliances applies regardless of where the natural gas is produced.

D. The Price of Natural Gas Consumption Within BC Includes the Cost of Carbon

59. The optimal balance of energy sources is achieved through efficient pricing, allowing British Columbians to make their own decisions regarding the appropriate energy source for particular end uses and paying the associated cost. This requires both electricity and the energy alternatives to be priced efficiently from a resource cost perspective. BC Hydro's opposition to Electric Load Avoidance DSM based on its potential to increase consumption of natural gas within BC fails to account for the fact that the cost of associated GHGs is already factored into the natural gas resource cost by virtue of consumers having to pay the carbon tax. Customers are expected to respond to that price signal by reducing consumption. The focus in this proceeding should instead be on getting the right price signals on the electricity side that reflect BC Hydro's marginal cost of supply.

60. The Province's Strategic Plan 2009/10-2011/12 emphasizes the role of the carbon tax in sending appropriate price signals to enabling customers to make choices with respect to energy consumption: "The tax has the advantage of providing an incentive without favoring one way to reduce emissions over another. It gives British Columbians a choice on how they wish to adapt their behavior to reduce their consumption of fossil fuels."[122]

61. Although BC Hydro has referred to its own emissions associated with FNU3 and Burrard as GHG-free after 2016 by virtue of a legislative requirement to purchase offsets, obviously the emissions within British Columbia associated with the operations of these facilities are not suddenly disappearing in 2016. The effect of offsets is really to add the cost of GHGs on to BC Hydro's cost of acquiring electricity from gas-fired generation. The requirement to purchase offsets sends efficient price signals to BC Hydro to ensure that it is not incented to generate electricity in this manner without considering the GHG cost. Logically, BC Hydro's GHG argument against Electric Load Avoidance DSM should fall away if consumers of natural

[121] Exhibit C13-5, at 79.

[122] Exhibit C13-6, The BC Strategic Plan 2009/10-2011/12.

gas in BC purchased offsets. Natural gas consumers are, of course, currently free to purchase offsets but are not obligated to do so. Instead, domestic natural gas consumers are required to pay the carbon tax.[123] The carbon tax provides the desired price signal that would be provided by acquiring offsets.

62. BC Hydro has implicitly acknowledged that offsets and the carbon tax provide alternative price signals for GHG emissions[124] by requesting confirmation from the Province that it will not be necessary for BC Hydro to purchase offsets and pay the carbon tax after 2016.[125] The fact that BC Hydro received that confirmation from the Province[126] reinforces that the Province shares BC Hydro's view in this regard.

63. The Terasen Utilities are not suggesting that offsets are merely a "paper exercise", in the pejorative sense, as BC Hydro has understood. Rather, the submission is that the carbon tax and offsets are different ways of achieving a real, measurable reduction in GHGs through efficient pricing. The amount of the carbon tax paid in respect of domestic natural gas consumption and the amount of offsets required by BC Hydro to address emissions from its gas-fired generation would reflect the relative efficiency of end use consumption (80-95%) versus gas-fired generation (30% for Burrard). Ultimately, the right pricing in either case should result in the efficient amount of consumption.

64. Later in these submissions we address the fact that BC Hydro's GHG offsets for its gas-fired generation are unlikely to be acquired exclusively from within BC, meaning that the GHG benefit that forms the basis of the offset occurs regionally. Offsets within BC have the same value from a climate change perspective as offsets acquired outside BC, but acquiring offsets exclusively within BC will cost upwards of three times as much for BC Hydro's customers. This is another illustration of the importance of taking a regional view to GHG emissions, and not examining only provincial GHG emissions.

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[123] Transcript, Vol. 6, at 872.

[124] Transcript, Vol. 6, at 866 (BC Hydro's witness acknowledged that both offsets and carbon taxes provide "provide an economic disincentive..."; see also Transcript, Vol. 6, at 871-872.

[125] Transcript, Vol. 6, at 823-824; Transcript, Vol. 6, at 870 (confirming Ms. Van Ruyven's statement).

[126] Transcript, Vol. 6, at 823-824.

65. In sum, on the natural gas side of the resource analysis, efficient pricing has been achieved by the GHG emissions associated with the consumption of the natural gas being subject to the carbon tax or a requirement to purchase offsets. The task at hand is to ensure that electricity is also priced appropriately.

E. Summary Regarding Regional GHG Emission Reduction and Efficient Pricing of GHGs Within BC

66. BC Hydro's objection to Electric Load Avoidance DSM is rooted in the assumption that natural gas is the logical alternative energy source. BC Hydro discounts the future potential for British Columbians to adopt other alternative energy sources without considering the effect low electricity rates have on the development of the market for these alternatives. The potential to reduce GHG emissions on a regional basis, combined with the obligation on British Columbians to pay the carbon tax on domestic gas consumption, eliminates BC Hydro's primary policy basis for opposing Electric Load Avoidance DSM. BC Hydro should be pursuing Electric Load Avoidance DSM to the economic benefit of BC Hydro ratepayers as a whole with the comfort that its initiative is consistent with the worthwhile objective of mitigating climate change.

VI. EXISTING POLICY FRAMEWORK SUPPORTS EFFICIENT CHOICES AMONG ENERGY SOURCES

67. BC Hydro must, by virtue of section 44.1(2)(b) and (f) of the UCA, explain why it is not pursuing cost-effective Electric Load Avoidance DSM to reduce (all else equal) electricity rates for its customers. BC Hydro's approach has been to frame the Electric Load Avoidance DSM issue as a policy choice between British Columbians using clean electricity or GHG-emitting natural gas for particular end uses.[127] A more nuanced approach is required, which recognizes the benefits to customers in terms of lower rates (all else equal), the availability of an increasing variety of energy alternatives to electricity, regional GHG benefits, and the fact that gas consumers in BC must pay for GHG emissions through the carbon tax as a form of price signal. In this Part the Terasen Utilities makes the following points:

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[127] See, for instance, BC Hydro Submissions, at 51-71

(i) Where alternatives to electricity exist for particular end use applications, the objective should be to identify, in the words of the Energy Plan, the "right fuel, for the right activity, at the right time".

(ii) Electric Load Avoidance DSM can be used to counteract inefficient price signals inherent in rates that primarily reflect embedded costs that can cause customers to adopt electricity as an energy source where it is not efficient to do so from a TRC perspective. Customers are free to choose the right fuel for their purposes based on more efficient price signals. This cannot be equated with being "pro-natural gas".

(iii) The Province's pursuit of electrification initiatives reflects its policy of "the right fuel, for the right application, at the right time", and is not evidence of Government opposition to Electric Load Avoidance DSM.

(iv) The *Greenhouse Gas Reduction Targets Act* ("GGRTA") is not an appropriate basis to preclude BC Hydro from pursuing cost-effective Electric Load Avoidance DSM for the benefit of its customers.

(v) Electric Load Avoidance DSM represents an opportunity to reinforce the need for British Columbians to consider energy efficiency.

(vi) BC Hydro's concern about customers "locking in" to a bad fuel choice is misplaced, and BC Hydro should be concerned about the impact of its policies on its customers as a whole.

68. BC Hydro has an opportunity to demonstrate initiative in advancing Government policy through the pursuit of cost-effective Electric Load Avoidance DSM.

A. "Right fuel, for the Right Application, at the Right Time"

69. BC Hydro says that it is awaiting a clearer government directive before pursuing Electric Load Avoidance DSM.[128] However, Government's current neutral position on energy choice is not a policy void. The Energy Plan identifies a future role for electricity, natural gas, and alternative energy sources supplemented by natural gas.[129] The policy emphasis in the Energy Plan is on the importance of making efficient choices among energy sources available for particular end uses, rather than expressing a single preference for any energy source. For example:

[128] Transcript, Vol. 3, at 281-282

[129] Exhibit B-1-1, Appendix B1 at 24.

> It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. [130]

70. Although Mr. Elton at one point rather dubiously characterized the above quoted passage from the Energy Plan as "just one of those good statements that people put into these kinds of policies" as opposed to being an expression of policy,[131] BC Hydro did acknowledge on other occasions that Government policy emphasizes energy efficiency.[132] It would be at odds with this policy for Government to state a preference for one energy source, for all activities, for all time. BC Hydro customers will benefit from BC Hydro applying the policy of "the right fuel, for the right activity, at the right time".[133]

B. Efficient Price Signals *Versus* Being "Pro-Natural Gas"

71. BC Hydro characterizes Electric Load Avoidance DSM as "an action by BC Hydro, as part of its DSM programs, to financially incent customers (who would otherwise select electricity as the energy form) to select natural gas as the energy form."[134] The use of financial incentives is an important aspect of Electric Load Avoidance DSM; however, the implicit suggestion that pursuing cost-effective Electric Load Avoidance DSM requires BC Hydro to be "pro-natural gas" is not correct.

72. Cost-effective Electric Load Avoidance DSM acts in conjunction with the existing conservation rate structures (such as the RIB rate), to *counteract* the fact that electricity rates based on embedded costs encourage customers to adopt electricity as an energy source

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[130] Exhibit B-1-1, Appendix B1 at 24; Exhibit C13-5 at 61.

[131] Transcript, Vol. 3, at 280-281. Contrast this statement to Mr. Elton's characterization of other parts of the energy Plan as deliberately allowing for flexibility. In response to a question from Mr. Oulton that there is no legislated requirement on the Burrard timetable, Mr. Elton stated at Transcript, Vol. 5, at 694 that "There is no legislative requirement, therefore it's one of those areas where you – I think you seek to be in the right – in the same direction as government policy, and you seek to use the flexibility that they've offered."

[132] Transcript, Vol. 3, at 281-282.

[133] In effect, this results in BC Hydro returning to the policy it pursued until the 2007 Rate Design proceeding, exemplified by the following statement on its website: "We encourage customers to think about how they use energy. It's important to match your energy source to its best use. Electricity is best suited for lighting and powering our appliances and televisions, whereas natural gas is ideal for space and water heating." Exhibit C13-9, at 4.

[134] BC Hydro Submissions, at 62, lines 3-5.

where the TRC analysis demonstrates that electricity is not the most efficient fuel alternative for particular end uses. BC Hydro's low electricity rates have the unintended consequence of constraining customer choice, as illustrated by the fact that the measures identified in the CPR as having a TRC of one or more all resulted in a negative or excessive payback period for customers.[135] Electric Load Avoidance DSM drives customers to make decisions among energy sources recognizing BC Hydro's avoided marginal cost of supply, unconstrained by relative price differences in capital costs or embedded cost-based electricity rates. Natural gas was the only fuel alternative studied in the 2007 CPR, but heat pumps and other alternative energy systems also represent potential alternatives to electric baseboards, for example, that a customer could choose from when the economics make sense or where a customer's personal values play an important role in the choice. BC Hydro should not assume that electricity will be each customer's moral choice as they appear to do in their final argument.[136] Once the inefficient price signals inherent in the existing electricity rates are mitigated by Electric Load Avoidance DSM incentives, customers may choose other alternatives.

73. BC Hydro cites at page 62 of its submission's Mr. Elton's evidence that "[BC Hydro has] sought clarification on this and received the answer, it isn't government policy to encourage fuel switching from electricity to natural gas." BC Hydro also cites Ms. Van Ruyven's statement that: "I don't believe there is any government policy that specifically says that BC Hydro should encourage fuel switching from electricity to natural gas". There is nothing in either of these statements to suggest anything other than a neutral stance on fuel choice.

74. Ms. Van Ruyven also recounted government representative as indicating that government would not formulate a policy that would result in BC Hydro promoting a program that would incent an increase in GHG emissions within B.C.[137] BC Hydro has not taken such an unequivocal stance with respect to its own programs that would result in increased GHG emissions in the province. FNU3, for instance, results in greater GHG emissions within British Columbia.[138] BC Hydro's response to this is to cite carbon offsets as negating the physical GHG

[135] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108 & footnote 65.

[136] BC Hydro Submissions at 62, line 7, item (2).

[137] BC Hydro Submissions at 63.

[138] FNU3 results in less GHGs per GWh, but the generation capacity will increase significantly such that GHGs will increase overall. See Exhibit B-12, Response to Terasen IR 3.8.1.

emissions; but, as discussed previously, natural gas consumption is subject to an equivalent carbon pricing mechanism in the carbon tax. All of this illustrates that Government policy must be more nuanced than to preclude BC Hydro initiatives that result in GHGs in the province.

75. The Terasen Utilities are not suggesting that the Province has a policy of favouring a particular energy source for particular end use applications, a misconception that seems to underlie a number of BC Hydro's submissions.[139] Rather, the Terasen Utilities rely on the express wording of the Energy Plan and the Government's stated preference for choosing the "right fuel, for the right activity, at the right time".

76. Where energy alternatives do exist, it is imperative that the appropriate rate and incentive mechanisms, as well as consistent messaging, are put in place to inform available energy choices and free customers to make choices among energy sources that are efficient from a TRC perspective for a particular application. BC Hydro has acknowledged that providing right price signals can "encourage customers to make energy efficient choices."[140] BC Hydro will apply Provincial policy by encouraging customers to use energy more efficiently through Electric Load Avoidance DSM.

C. Electrification Initiatives

77. BC Hydro cited in opposition to Electric Load Avoidance DSM that "one of the most significant GHG implementation uncertainties from a fuel switching perspective is the extent of BC Government electrification initiatives."[141] BC Hydro provided two examples of electrification initiatives relating to the adoption of electricity at truck stops and ports in place of diesel and marine fuel.[142] To the extent that BC Hydro is suggesting that these initiatives are the beginning of a trend towards mass electrification, or evidence of Government opposition to Electric Load Avoidance DSM, it is reading far too much into these initiatives. BC Hydro has

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[139] For example, BC Hydro's response on page 63 to the Energy Plan's reference to "right fuel, for the right activity, at the right time" is to observe that "Noticeable by its absence is any reference to encouraging fuel switching from electricity to natural gas…". The inclusion of such a statement would be at odds with the Province's emphasis on the importance of choosing the "right fuel, for the right activity at the right time".

[140] Exhibit C13-9, at 5 (IR response from RIB Application proceedings)..

[141] Exhibit B-4, Response to BCSEA IR 2.29.2, at 48.

[142] Exhibit B-4, Response to BCSEA IR 2.29.2.

stated that the Province is neutral as to fuel choice.[143] Government's support for the development of natural gas is evident.[144] The Province has also promoted initiatives that use, for instance, liquefied natural gas to fuel heavy-duty trucks.[145] In short, the electrification initiatives cited by BC Hydro, like the Province's support for the LNG initiative cited above, are simply a reflection of the Province's policy favouring "the right fuel, for the right activity, at the right time".

D. "Provincial" GHG Emissions

78. BC Hydro interprets the provincial emissions reduction target in the GGRTA as a prohibition against pursuing cost-effective Electric Load Avoidance DSM, at least in so far as the alternative fuel is natural gas. There are several reasons, addressed below, why the GGRTA is not an appropriate basis to preclude BC Hydro from pursuing of cost-effective Electric Load Avoidance DSM for the benefit of its customers.

(ii) Mitigating Climate Change *versus* Pursuing a Target

79. BC Hydro's interpretation of Government policy is exemplified by Mr. Elton's response to the question of who benefited from the position BC Hydro was taking in a circumstance where GHGs were being reduced overall and BC Hydro customers were paying lower rates. He replied that the beneficiaries are "[t]he people who are living in a province that achieves its targets."[146] This analysis unjustifiably elevates to the status of ultimate objective one *means* by which Government has chosen to pursue its ultimate objective of mitigating climate change associated with GHG emissions.

80. The passages from the Energy Plan quoted by BC Hydro in its Submissions in support of this argument regarding the GGRTA[147] are ultimately emphasizing climate change. The Premier noted for instance, that "The world has turned its attention to the critical issue of global warming" and indicated that the ultimate purpose of the steps outlined in the plan was "arrest the growth of greenhouse gases and reduce human impacts on the climate".[148] The

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[143] Transcript, Vol. 3, at 275.

[144] See, e.g., Energy Plan, Exhibit C13-5, at 61; 2010/2011 Strategic Plan, Exhibit C13-6.

[145] Exhibit C13-5, at 60.

[146] Transcript, Vol. 3, at 289.

[147] BC Hydro Submissions, at 51.

[148] Exhibit B-1-1, Energy Plan, at 4.

passage from Message from the Government in the Climate Action Plan similarly opens with the statement "Global warming is the challenge of our generation."[149] The GGRTA target and Government's ultimate objective of climate change mitigation are aligned in most cases, which makes the GGRTA a useful tool in combating climate change. However, where the legislated target and the ultimate objective are at odds, the *means* should not trump the *end goal.* It is important in the case of Electric Load Avoidance DSM to keep in mind that the ultimate objective behind the legislation is mitigating climate change because the associated GHG emission reductions are regional. BC Hydro customers (and British Columbians generally) benefit from lower GHG emissions, irrespective of whether the reduction occurs in BC or across the BC-US border.[150]

81. The Province has used other legislation to achieve its climate change objectives, which do not focus exclusively on provincial emissions. The UCA, i.e. the legislation that defines the Commission's jurisdiction, refers to "government's energy objective" as being "to encourage public utilities to reduce greenhouse gas emissions". Although the GGRTA focuses on provincial emissions, the Government objective identified in the UCA is unqualified by reference to "*provincial*" GHGs or the province's GHG targets under the GGRTA. The Western Climate Initiative ("WCI"), to which the Province is a member, is a regional initiative to combat climate change.

82. Government's promotion of natural gas development in the Province[151] is another example of a circumstance where taking BC Hydro's approach would ultimately run counter to the Province's support for mitigating climate change. The production of natural gas contributes 18% of BC's total GHG emissions.[152] However, the consumption of natural gas in end use

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[149] British Columbia Climate Action Plan,, available at: <http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf>, at 1.

[150] Transcript, Vol. 6, at 811-812.-

[151] Exhibit B-1-1, Appendix B1, at 32. Exhibit C13-5, at 64. The Energy Plan states that it "is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector." Government has since continued to sell land for resource development and the sales have attracted record levels of land sale bonuses in the last two years. See Exhibit C13-5, at 62 (Minister Neufeld's Press Conference Statement). In Exhibit B-12, Response to BCUC IR 3.248.1, BC Hydro acknowledged this fact. "Land sales in Northwest B.C. significant [sic] increased during 2008, signaling that there could be a strong potential for future development of natural gas reserves in the region."

[152] Exhibit B-1-1, Appendix B1, at 23. Mr. Elton suggested that although government is interested in promoting many activities that will increase GHG emissions in the province the GHG reduction target would have taken

appliances has a significantly lower emissions factor (200 tonnes/GWh)[153] than the emissions factor applied to BC Hydro's imports in 2006 (550 tonnes per GWh).[154] This is still the case where the natural gas is consumed in a CCGT at 50% efficiency to generate electricity (360 tonnes/GWh).[155] Thus, it is better from a climate change perspective to produce and consume natural gas anywhere in the WECC region for direct use applications or for gas-fired generation than it is to generate electricity using a higher emitting energy source such as coal. Coal generation emits about twice the amount of GHG per GWh than does natural gas-fired generation.[156]

(iii) BC Hydro's Regional Approach to Offsets

83. As outlined in Part III of these Submissions, the successful implementation of cost-effective Electric Load Avoidance DSM results in a direct benefit to BC Hydro customers in the form of lower rates (all else equal). BC Hydro is already pursuing other policies for the benefit of its customers that result in provincial GHG emissions. FNU3 and the continued use of Burrard, both of which BC Hydro advocates, will generate GHG emissions in the province.[157]

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into account these expansions in natural gas development. (Tr. Vol. 3 page 293 lines 14-23). However, at the time the 33% target was announced in the 2007 Throne Speech (Exhibit B-1, page 4-5, footnote 52, link to B.C. News Release on BC joining WCI) the gas production forecasts were indicating only modest growth. (Exhibit B-3, BCUC IR 1.67.1, Attachment 2, Climate Action Plan, Appendix I, page 100-101, which references NRCan's 2006 forecast.) The subsequent pursuit of the Horn River play has resulted in a step change in these forecasts. The CAPP letter filed by BC Hydro (Exhibit B-1-1, Appendix B1, at 23) indicates that "Production from the Horn River Basin shale gas is forecast to grow from approximately 50 mmscf/d million cubic feet per day) in 2009 to approximately 2,700 mmscf/d by 2020. The forecast is derived from a survey of the area operators of the HRPG which requested their anticipated annual drilling well count and the associated production. The well count derived is approximately 80 in 2009, growing to over 200 wells per year in 2016, then maintaining that level. It is anticipated that there could be a total of 2,200 wells producing in 2020." This step change in BC's natural gas production levels will lead to an associated increase in GHG emissions produced in BC.

[153] CPR, Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at 121 of 138, notes that the number on the record is 180 tonnes/GWh for direct use of natural gas. However, this appears to correspond to 100% efficiency. 90% efficiency, by our calculations, is closer to 200 tonnes per GWh, so we have used this amount in these Submissions.

[154] Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at 121. Also, it is clear that emissions levels in the WECC regional will remain at this level for some time, as estimated average performance standard in Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, and Wyoming. A performance standard is the GHG emissions level above which **offsets** must be acquired. (Exhibit B-1, p. 4-20 lines 14-21).

[155] Exhibit B-1, at 4-20, lines 4-10: "California, Washington State and Oregon require thermal plants to offset to the equivalent of a CCGT, This results in the California, Washington State and Oregon performance standards being set at 360 tonnes of GHG per GWh."

[156] Exhibit B-1-1, Appendix H, at 10-11.

[157] Transcript, Vol. 6, at 865-866. GHG emissions associated with FNU3 is discussed in Terasen IR 3.8.1. The Terasen Utilities take no position on whether FNGU3 is in the public interest, and recognize the value to BC Hydro of continuing to operate Burrard.

Unlike Electric Load Avoidance DSM, running these facilities does not deliver an offsetting GHG reduction elsewhere in the Pacific Northwest. These initiatives illustrate the need to balance government's interest in reducing GHG emissions against other competing objectives.

84. BC Hydro seeks to distinguish the "provincial" emissions associated with Burrard and FNGU3 from the emissions associated with domestic natural gas appliances by pointing to the requirement to offset the GHG emissions associated with its facilities after 2016, and the absence of any existing obligation on natural gas consumers to offset GHG emissions.[158] The inconsistency of BC Hydro's reliance on offsets with its failure to recognize the carbon tax as a means for pricing carbon was discussed above. In the context of the regional approach to GHG emissions it is noteworthy that BC Hydro will likely purchase offsets outside the province in order to reduce the costs of purchasing those offsets.[159] This requires a regional perspective towards GHG emissions, analogous to that being advocated by the Terasen Utilities. In the case of offsets acquired outside of BC, the GHGs will be emitted in British Columbia, while the GHG reduction that forms the basis for the offset will be occurring outside of British Columbia. There is no logical distinction between acquiring offsets from outside British Columbia and (i) using electricity "freed-up" by Electric Load Avoidance DSM to displace gas or coal-fired generation on the margin, or (ii) exporting BC's natural gas to reduce GHG emissions in the WECC region. Extra-provincial offsets are being considered by BC Hydro because they will cost less and ultimately save customers money.[160] Electric Load Avoidance DSM should also be considered for this reason, among others.

E. Conflicting Messages to the General Public

85. Counsel for BCSEA-SCBC raised in his Opening Statement a concern that promoting electricity to natural gas Electric Load Avoidance DSM programs would create confusion with regard to reducing GHG emissions and burning fossil fuels.[161] BC Hydro's

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[158] Exhibit B-12, Response to BCUC IR 1.22.2; BC Hydro Submissions at.67, lines.8-11.

[159] Transcript, Vol. 9, at 1532-1534.

[160] Exhibit B-1, at 4-10 and Table 4-2; The B.C. only case for establishing the cost of offsets was not considered likely by Natsource in its modeling of the cost of offsets. Table 4-2 indicates that the expected cost of offsets from a B.C. only case would be three times or more the expected cost of offsets if they were acquired from within the WECC.

[161] Transcript, Vol. 3, at 222-223.

witnesses echoed this position during the hearing[162] and BC Hydro repeated it in its Submissions.[163] There is no evidence to support this contention that the public will be confused. Rather, the evidence is that the Province has emphasized in the Energy Plan the importance of "for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity, at the right time". BC Hydro, until after the 2007 Rate Design Application proceeding, adopted a nuanced approach, as exemplified by its website encouraging customers to match their energy source to its best use.[164] Other utilities in the Pacific Northwest (the examples in the record are Avista and Puget Sound Energy) continue to take a more nuanced view, with the apparent approval of regulators,[165] in the confidence that people will understand the value in making efficient fuel choices. The pursuit of Electric Load Avoidance DSM presents an opportunity to reinforce the need for British Columbians to consider and "understand the appropriate uses of different forms of energy".[166]

F. Lasting Implications of Customer Decisions Regarding Energy Source

86. During the hearing BC Hydro's witnesses suggested that BC Hydro was reluctant to encourage the adoption of natural gas as an energy source for particular end uses out of concern that customers who switch to another energy source would be subjected to high future gas prices and operating costs.[167] The concern here, as characterized by BC Hydro, is that "[i]f that choice ends up to be a bad choice, particularly if that choice was originally made when all the signposts were that electrification of space heating may be required to meet climate action targets, BC Hydro could be seen by that customer in a bad light as a result of such encouragement. Recall, customers have long memories."[168] There are a number of problems with BC Hydro's approach.

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[162] Transcript, Vol. 3, at 284.

[163] BC Hydro Submissions at 71, l.25 to 72, l.15

[164] In response to Terasen's Information Request in BC Hydro's 2007 Rate Design Application proceedings, BC Hydro stated that "in the past, BC Hydro encouraged customers to use natural gas instead of electricity for space heating, based on economic and environmental considerations. BC Hydro is reviewing this practice in light of the 2007 Energy Plan." See Exhibit C13-9, at page 5.

[165] See for instance, Exhibit C13-9, at 11-12, the staff decision from the Washington Utilities Transportation Commission in respect of Puget Sound Energy's programs.

[166] Exhibit C13-5, at 61.

[167] Transcript, Vol. 9, at 1521 - 1522.

[168] BC Hydro Submissions, at 66..

87. First, this paternalism is at odds with the Province's approach to facilitate British Columbian's ability to make energy choices based on efficient price signals, as exemplified by the carbon tax. The Province's Strategic Plan 2009/10-2011/12 emphasizes the role of the carbon tax in sending appropriate price signals *to enable customers to make choices* with respect to energy consumption.[169]

88. Second, BC Hydro's vision of the future from which it is protecting its customers is suspect. With respect to BC Hydro's reference to natural gas price increases, BC Hydro's witnesses testified as to their expectation that the sustainable long-term gas prices will be in the $6 to $8 per MMBtu range.[170] All of the gas price forecasts provided by BC Hydro (except that of its own internally developed high gas price forecast and internally developed weighted average) reside below or in the lower part of this range until 2020.[171] In contrast, electricity prices have been rising steadily and will continue to do so.[172]

89. Third, in making this judgment for customers, BC Hydro is according insufficient weight to the fact that its customers *as a whole* will pay higher electricity rates (all else equal) as a result of the customer choosing electricity over another energy source due to the embedded cost-based electricity rates or relative capital cost of adopting a particular alternative energy source.[173] Customers paying higher rates in the future (all else equal) may look back on BC Hydro's opposition to counteracting inefficient price signals that have the effect of encouraging electric space and water heating load as a "bad" decision. This is particularly so where GHGs can also be reduced on a regional basis. Once individual customers faced with a choice among energy sources for particular end uses choose electric appliances as a result of those price signals, BC Hydro is locked in to that decision, and customers as a whole must pay for it.

90. There is no justification for this paternalism evidenced in BC Hydro's submission. BC Hydro should pursue Electric Load Avoidance DSM as a means of establishing more

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[169] Exhibit C13-6, The BC Strategic Plan 2009/10-2011/12.
[170] Transcript Vol. 10 at 1888-1889.
[171] Exhibit B-32.
[172] Exhibit B-10, at 25.
[173] See, for example, Exhibit B-4, Response to BCUC IR 2.206.3.

efficient price signals, and allow the customers to make the choice as to the energy source they adopt for particular end uses.

G. Summary

91. Electric Load Avoidance DSM can be used to counteract inefficient price signals inherent in rates based to a significant extent on embedded costs, with resulting economic benefits to BC Hydro customers and a provincial and regional GHG reduction. Mitigating increases in electricity rates through cost-effective Electric Load Avoidance DSM, and reducing GHG emissions in the process, is aligned with provincial policy as reflected in the Energy Plan and "government's energy objectives". It is also in the public interest, which is the ultimate test to be applied by the Commission in this Application.

VII. COMMISSION DETERMINATIONS AND NEXT STEPS

92. As indicated previously, the Terasen Utilities are cautiously optimistic about BC Hydro's new overtures to investigate Electric Load Avoidance DSM. However, certain parameters that BC Hydro has placed on the inquiry in the high level discussion that appears on pages 57-59 of its Submissions suggest that there remain fundamental disagreements among the intended participants in the study process that require the Commission's intervention at this time. The Terasen Utilities respectfully submit that the evidence on the record supports the following findings, which should be made express in the Commission's decision in order to help to frame the study:

(i) The pursuit of cost-effective Electric Load Avoidance DSM can be used to achieve efficient pricing, which in turn will allow customers to make appropriate fuel choices.

(ii) To the extent that customers faced with efficient price signals adopt another energy source it will contribute to BC Hydro's efforts to close the load-resource gap, thus avoiding the need to acquire new higher cost electricity supply for that portion of the demand. This will result in lower electricity rates (all else equal) for BC Hydro customers as a whole.

(iii) Using cost-effective Electric Load Avoidance DSM to achieve efficient pricing is consistent with the Energy Plan's emphasis on the "right fuel, for the right activity, at the right time", and is consistent with the Province's neutral position on choice of energy source.

(iv) The potential for GHG reductions outside of the province as a direct result of pursuing cost-effective Electric Load Avoidance DSM suggests that BC Hydro should be pursuing cost-effective Electric Load Avoidance DSM.

(v) The way in which the GGRTA measures GHG emissions, i.e. on a provincial basis, does not and should not prevent BC Hydro from pursuing cost-effective Electric Load Avoidance DSM to reduce rates for BC Hydro customers (all else equal). The presence or absence of a requirement to offset GHG emissions is not determinative in the context of Electric Load Avoidance DSM as the energy alternatives adopted by customers will have the cost of carbon priced in to them by way of the carbon tax.

93. BC Hydro acknowledges the Commission's jurisdiction to direct a study of Electric Load Avoidance DSM.[174] The Commission should issue the following additional directions to BC Hydro to guide its future work. These directions are consistent with the evidence in this proceeding and are appropriate in the circumstances:

(i) The cost-effectiveness of Electric Load Avoidance DSM should be determined with reference to the Total Resource Cost (TRC) test.

(ii) In performing a TRC analysis for Electric Load Avoidance DSM, BC Hydro should be using an updated avoided cost (before line losses) of at least $120/GWh. In the case of programs directed at space heating load, BC Hydro should be using time of delivery weighting per the approach adopted in Exhibit B-73.

(iii) Cost-effective measures (i.e. those with a TRC ratio of benefits to costs of greater than 1.0) should not be eliminated from consideration as a means of addressing the load-resource gap based on a simple payback analysis using current rates paid by BC Hydro customers.

(iv) Part of BC Hydro's study must include exploring different incentive models within the framework of Electric Load Avoidance DSM.

94. The Terasen Utilities submit that it is unnecessary to reject any part of the LTAP provided that appropriate Commission directives are in place and that the current two-year LTAP cycle is maintained.

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[174] BC Hydro Submissions, at 22

VIII. CONCLUSION

95. BC Hydro has an opportunity to close the forecasted load-resource gap by pursuing Electric Load Avoidance DSM in tandem with its proposed *load reduction* DSM. BC Hydro customers will benefit from lower rates than would otherwise be the case if BC Hydro pursues Electric Load Avoidance DSM having a TRC benefit/cost ratio of more than one. British Columbians will benefit from reduced GHG emissions in the region. The legislative and policy context, exemplified by "government's energy objectives" and the Energy Plan policy of "right fuel, for the right activity, at the right time", supports the pursuit of cost-effective Electric Load Avoidance DSM in priority to acquiring higher cost supply. The Terasen Utilities look forward to working productively with BC Hydro and other stakeholders to develop appropriate terms of reference for the further study of Electric Load Avoidance DSM in line with the Commission's direction.

ALL OF WHICH IS RESPECTFULLY SUBMITTED,

[Original signed by Matthew Ghikas]

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Matthew Ghikas
Counsel for the Terasen Utilities

[Original signed by Song Jin Hill]

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Song Jin Hill
Counsel for the Terasen Utilities

April 27, 2009

WRITTEN SUBMISSION FROM:

THE PEMBINA INSTITUTE

PEMBINA
institute

October 18, 2013

Advice to BC Hydro Regarding the Draft Integrated Resource Plan

by Matt Horne & Tom-Pierre Frappé-Sénéclauze | 604.874.8558 x 223 | matth@pembina.org

Overview

The Pembina Institute appreciates the opportunity to provide comments on the draft IRP. On balance, the efforts on BC Hydro's part to analyze options and make that analysis available to TAC participants have been commendable. We have grouped our recommendations under the following headings:

- Scenario planning
- Clean energy act objectives
- Conservation
- New supply
- TAC process

One overarching challenge of this planning exercise is the fact that the economic and energy policy context in the province is in a period of rapid change, and has been for the last few years. To account for the potential of these fluctuations continuing, BC Hydro should prioritize flexibility in planning for new load and supply options. BC Hydro made commendable efforts to keep options open while reducing expenditures in the short term (IPP portfolio optimization, DSM expenditures revisions, advancing studies for GM Shrum upgrade and Revelstoke 6), yet fails to properly value flexibility in other decisions (Site C, limiting research on DSM options 4 and 5).

Looking at the changes in forecasted load resource balance (LRB) over the IRP drafting period shows a clear indication of the shifts in the planning landscape over the last two years. Between late 2011 and August 2013 the IRP analysis went from predicting an LRB in significant deficit over the entire planning period, to predicting a surplus for the next five to ten years. Taking the base case estimates for F2024 as an example, the LRB prediction went from a deficit of 9,046 GWh to a surplus of of 690 GWh, a swing of nearly 10,000 GWh[1].

There were both policy and economic drivers for this rapid change in the forecast. About half of the shift was due to the redefinition of the self-sufficiency requirement in

[1] Calculations based on BC Hydro data, spreadsheet available at: http://pubs.pembina.org/reports/energy-load-resource-balance-changes-bch-pembina.xlsx

February 2012[2], and ten percent was due to a revision of expected supply from IPPs (revised downward until F2021, upward after that). About 15 percent of the shift came from a reduction in the load forecast for residential, commercial, and industrial customers, and another 25 percent from the reduction in LNG base case load. Together, these factors changed the load resource balance predictions by up to 2.6 times the average energy expected from Site C. This is a significant shift in less than two years of planning, and we have reason to expect further shifts as various drivers, such as the size and pace of LNG, climate and environmental policy, technological innovation, and the role of distributed generation, are in rapid evolution.

Our recommendations suggest some ways to partially address this uncertainty by having BC Hydro maximize the flexibility of its supply and DSM options, and play a constructive role in advancing public conversations about a broader set of possible future energy policy environments. That said, it is paramount that the B.C. government also take a more proactive role in facilitating a dialogue with British Columbians about developments like LNG with such wide ranging and significant costs and benefits.

Scenario planning

1. **Explore changes to provincial energy policy:** In the same way that BC Hydro has made good efforts to assess a range of market factors in developing the IRP, we recommend adopting a planning approach that assesses a range of provincial energy and climate policies. We recognize that BC Hydro does not want to be perceived as undermining the provincial government's role to set policy, but we believe it is important for its responsibility in long term electricity planning to consider the outcomes of a range of possible policies. Given that there were at least two major changes to provincial policy during the development of the IRP (self-sufficiency and LNG clean energy requirements), it seems prudent to ensure the robustness of the planning exercise and explore a range of potential futures.

   In order to avoid a conflict with the province's roles and responsibilities, this additional scenario planning should focus on a range of plausible futures without attempting to apply probabilities to them. It would also likely be more successful if it avoided specific policy instruments and instead focused on the types of outcomes those policy shifts could drive. As an example, a possible variable would be the degree of regional environmental protection in the province, which would have general impacts on the costs and availability of new supply options. There would be many ways that provincial governments could influence regional environmental protection (e.g. environmental assessment, protected areas, environmental pricing/taxation, water use planning, etc.), but the specific policy

[2] Self-sufficiency previously required BC Hydro to plan based on critical water level, and to plan for an additional 3,000GWh insurance after F2020. In February 2012, the definition of self sufficiency was readjusted to allow planning based on average water levels (thus reducing the resource load balance gap by 4,100 GWh), and to remove the insurance requirement.

tool would not be the focus of the IRP, just the implications for resource planning needs and options. Similarly, the IRP could explore other possible policy spaces based on factors like the degree of climate protection (i.e. preference for fossil-fuel energy versus low-carbon options), the priority placed on energy self-sufficiency versus regional grid reliance, etc.

From this map of possible futures, the IRP would then focus on the current policy context and make plans that are commensurate with current priorities. However, as these priorities shifts, there would remain a broader context to understand and prepare for the consequences of different policies.

2. **Develop and utilize better tools to help decision makers and the public understand the issues and tradeoffs:** The significant documentation for the IRP is an important part of the process that provides transparency for those with the ability to assess the details. While we support continuous improvement in this documentation, it is also important to acknowledge its limitations in reaching audiences that are not able to explore the material in significant detail. To address this limitation, we recommend that BC Hydro develop and utilize interactive tools that make the issues being explored in the IRP more accessible to decision makers and the public. Although the details of resource planning are undeniably complex, the economic, environmental and social tradeoffs can also be presented in a simple and intuitive manner that allows a broader audience to engage in the process more meaningfully. The Pacific Institute for Climate Solutions citizens engagement stream of research could be a useful local resource in exploring these types of communication and engagement tools.

Clean Energy Act objectives

While our previous recommendations support the idea of exploring alternative provincial energy policy futures, we recognize that BC Hydro has an obligation to comply with existing legislation.

3. **Provide overall assessments of performance against *Clean Energy Act* objectives:** The executive summary of the IRP currently lists most of the *Clean Energy Act* objectives, but it provides only a limited assessment of how the IRP preforms against those objectives. Table 1-1 provides some of this assessment: in some cases assessing the IRP's performance against the objective, and in others assessing how individual actions relate to objectives without assessing if the net impact of actions is sufficient to meet the CEA objective. We recommend that all objectives be assessed at an IRP level (i.e. does the set of actions in the IRP as a whole meet the objective, in addition to an action level assessment if appropriate) and that a concise version of that assessment be included in the executive summary.

4. **Communicate that B.C.'s GHG targets are likely to be missed under current provincial policy and the IRP actions:** Table 1-1 indicates how different actions will help the province reduce greenhouse gas emissions. While this is useful and relevant information, the draft IRP does not explain how well the province will be doing against its overall GHG targets in 2020 and slightly in advance of 2050. Responsibility for meeting those targets clearly falls to the provincial government, but from our perspective, BC Hydro has an opportunity and responsibility to go beyond presenting greenhouse gas reductions and to help decision makers and the public understand what the IRP means for provincial greenhouse gas emissions.

   Based on analysis Pembina completed on the province's objective of having three to five LNG plants, it is almost certain that B.C. will miss its 2020 greenhouse gas reduction target based on current provincial policies and the actions in the IRP. The actual emissions will depend on the level of development and the technologies used to limit emissions, but based on a scenario of just one large project proceeding (24 million tonnes of LNG per year), the emissions from natural gas extraction and processing, and the LNG facilities, are estimated to be 21 million tonnes per year — 53 per cent of the provincial target for 2020. Given that the facilities will be operational into the 2040's and beyond, it is equally important to acknowledge the degree to which they would consume B.C.'s emissions target for 2050 (11 million tonnes for the entire province).

   We do not expect BC Hydro to figure out how B.C. is going to meet its greenhouse gas reduction targets, but we do think BC Hydro should be clear to decision makers that one of the consequences of the IRP is almost certainly to be B.C. missing its targets.

Conservation

There have been a number of encouraging shifts in the analysis and characterization of demand side management opportunities through the IRP process (e.g. the redevelopment of DSM option 5 and improvements to some of the language that characterized DSM in a negative light). These are on top of improvements from the last long-term acquisition planning process that did not look at DSM options more expensive than the cost of supply. We still see several areas in the draft IRP where conservation efforts could be improved.

1. **Accelerate timelines for DSM options 4 and 5:** We do not agree with the lack of urgency regarding the investigation and potential deployment of activities in DSM options 4 and 5, which wouldn't move forward until at least the next IRP is completed (potentially 2017). We understand that the lack of data on potential energy and capacity savings from these options complicate their inclusion in supply options and expenditure plans; however, until further research is conducted to pilot and evaluate these approaches this will remain a self-fulfilling prophecy, and we will miss a potential opportunity for long term savings provided

by these DSM options. Some resources were allocated in recommended action 3 to advance some of the codes and standards research called for in options 4 and 5; however, from our perspective, the scope of effort is not sufficient to ensure adequate information is available to include options 4 and 5 in future planning. This information should be available when DSM expenditures ramp up again in or around F2017, and before a decision is made on Site C.

2. **Accelerate timelines for capacity DSM options:** Similarly to the previous recommendation, language on this in the draft IRP does not convey a sense of urgency in the explorations of capacity focused DSM, which is incongruent with the fact that BC Hydro is projecting relatively near term capacity constraints.

3. **Clarify the degree of DSM uncertainty that the provincial government can influence:** The uncertainty analysis conducted on DSM options has been a useful exercise that appears to have helped reduce the potential of overestimating expected savings from DSM options. However, it is important to acknowledge that there are different types of uncertainty, some of which can be influenced or completely controlled by the provincial government. For example, whether or not the provincial government is going to pass regulations for new lighting standards is something that is uncertain from BC Hydro's perspective, but something that the B.C. government can see with relatively high certainty because they make the decision as to whether regulations will proceed or not. BC Hydro has not indicated how significant these 'controllable' sources of uncertainty are, and because all of the sources of uncertainty are lumped together, decision-makers are presented with a picture of uncertainty that is overstated. The presentation of the IRP should be revised to indicate the different types of uncertainty.

New supply

4. **Include metrics of flexibility in portfolio analysis:** Some resource options offer more flexibility to BC Hydro than others; DSM expenditures and expected savings can be adjusted up or down depending on the short term forecast, as was done in this revision of the IRP. The current DSM plan decreased expenditure by $127M, a 22 percent decrease in the F2014-2017 plan proposed in the last draft of the IRP, while maintaining long term energy savings objectives. This is a timely example of the capacity of DSM to respond quickly to new load resource balance outlooks. Despite the obvious value of this flexibility, there is currently no way to explicitly include this as a decision factor in the portfolio analysis which guides the new supply outlook in the IRP.

   Similarly, through the recent IPP portfolio optimization process, the IPP contribution to the forecasted energy surplus was reduced by roughly 1,800 GWh, and a further 1,500 GWh was delayed by 0.5 to 2 years. This is another example of flexibility which would not be offered by committing to larger supply sources, like Site C. This adaptive advantage could be leveraged further going forward by releasing smaller annual calls for power based on the latest revisions of the load resource balance. Had we adopted such an approach instead of the large power calls of the early 2000s, we might not be finding ourselves in the current surplus situation. Incorporating a mechanism for pre-approval of projects, such as discussed in recommendation 9 below, could further decrease in-service time and allow for a more reflexive response to predicted mid-term load increases.

The current inability to assess and value the flexibility of different supply options is a significant shortfall which should be remedied, preferably as an explicit quantitative factor in the portfolio optimization. One way to do this, albeit computationally expensive, would be to consider various decision points with alternate scenarios along the planning horizon, and to calculate the risk of stranded assets for various supply options based on decisions along these multiple paths. Another approach could be to add a ‘flexibility credit’ akin to the ‘capacity credits’ used to adjust UEC and consider different values for flexibility when doing sensitivity analysis. Finally, portfolios should be compared to each other under a range of possible load resource balance gaps. This was done in the Site C sensitivity analysis, and shows that under a small gap scenario the NPV of Site C is more than a billion dollars more expensive than a more adaptive clean resources portfolio (Table 6-12).

5. **Account for deliverability and cost uncertainty for supply projects:** The draft IRP continues to suffer from a relatively weak approach to characterizing uncertainty on supply side resources apart from an assumed attrition rate for new projects. This stands in stark contrast to the excellent effort to characterize and account for uncertainty in DSM options. The implications of this weakness are unclear, but based on the relatively significant implications of assessing uncertainty in efficiency and conservation options, it would be prudent to apply a similar approach to supply side options.

   All supply-side options will have uncertainties about costs that will impact their attractiveness relative to each other and to DSM options. Site specific projects such as Site C that are not easily replaced with alternatives will also have uncertainty relating to deliverability (i.e. can the project be developed) that are not assessed in the IRP. Taking Site C as an example, there is a probability that it will not be approved, there is a probability that it will take longer to develop than anticipated, and there is a probability that its cost will differ from the estimate currently presented in the IRP. From Pembina’s perspective, these types of uncertainties seem material to the planning process in the same way that DSM uncertainties have proven to be. For the portfolio analysis, the energy savings expected for DSM measures is adjusted downward in an effort to reflect their uncertainty; to ensure a fair comparison, the average energy expected from supply options should be similarly adjusted to capture delivery uncertainty.

6. **Account for the impacts of climate change on new projects:** The draft IRP discusses climate change impacts for BC Hydro's existing system, and the conclusion relayed in the draft IRP is that the potential impacts are minor when looking out to 2050. This may be a valid conclusion for the existing system, especially within the planning horizon, but the level of analysis is inadequate for new projects given those projects will be operational into the 2060s and 2070s and beyond when climate change impacts are expected to accelerate. For example, changing flows on the Peace River could positively or negatively impact the timing and availability of energy from Site C, and those types of impacts need to be accounted for in the analysis. We recommend accelerating the next steps in BC Hydro's climate change adaptation strategy with a focus on assessing the implications for Site C and figuring out how to account for climate change impacts on power projects where BC Hydro is not the proponent. The analysis should also be extended beyond hydro-electric projects to assess the potential implications for wind and biomass resources.

7. **Delay construction decision on Site C:** For several reasons, we feel a decision to move ahead with Site C continues to be premature. BC Hydro has clearly not addressed the concerns being expressed by Treaty 8 First Nations and until those concerns are substantively addressed, it is not clear how the project would have free, prior and informed consent from those communities. The conclusion that Site C is the cheapest supply option does not appear to be robust enough to justify a multi-billion expenditure. Based on the information presented in the IRP, we consider a gradual commitment through smaller regular power calls to be a more fiscally prudent approach – even if costs might be higher.

   According to BC Hydro's portfolio analysis, without LNG, upgrades to GM Shrum and Revelstoke 6 would be sufficient to fill the capacity gap until F2027 (under DSM option 2, p. 6A-19) or F2028 (under DSM option 3, p. 6A-31). Even considering a seven year construction period, that would still provide until F2019 or F2020 to make a decision on Site C. This delay should be used to better understand the future of LNG, the role of distributed generation, and the conservation potential of DSM option 4 and 5, and thus inform the need for Site C. Given the magnitude of the expenditure, we also consider that it would be in the public interest for this project to be reviewed by the BCUC.

8. **Strengthening the analysis of Site C:** There are three specific areas where we think the analysis and consideration of Site C should be strengthened prior to committing to the project: accounting for cost uncertainty, strengthening the sensitivity analysis, and factoring in non-financial considerations.

   The assumption that Site C is a more cost effective option should be further tested for robustness. For a F2024 in-service date, The IRP estimates the NPV cost difference between Site C and an optimized clean resource alternative to be

630 million dollars: less than 8 percent of the estimated total cost of the investment for Site C. The gap nearly halves (360 million) assuming a ten percent capital cost overrun for Site C; cost overruns larger than this are not uncommon for large projects – particularly if there is competition for skilled labour from other large scale projects, like LNG plants, major pipeline construction, or a growth of NG sector in NE BC. We recommend that BC Hydro re-evaluate the portfolio cost comparisons once the cost implications of the previous four recommendations are considered, and after the cost estimate for Site C is revised based on new information that emerges from the joint review panel.

The sensitivity analysis conducted in Section 6.4 offers some insights, but is limited by the fact that each factor is only considered in isolation, and that some intermediate options are not considered. For example, the sensitivity analysis clearly shows that Site C is not cost effective under the low-gap scenario, with an additional NPV cost of over a billion dollars over the clean resource option. Given that BC Hydro only assigns a ten percent likelihood to this scenario, we also would recommend considering intermediate options, and a broader range of likely outcomes. This would help illustrate the size gap in which the clean portfolio is cost competitive with Site C, the likelihood of that outcome, and whether it can be achieved through more aggressive DSM. Furthermore, given that delaying Site C to F2026 shows to be more cost effective than meeting the earliest in service date of F2024, it would also be valuable to show what the cost advantages (if any) are to delaying Site C to F2028 or F2030. While we appreciate that there are limits to duration of environmental permits, if they are granted, we still would consider it a valuable source of information for BC Hydro and the government, who grants the aforementioned permits, to consider.

There are several non-financial factors where Site C differs substantially from the clean portfolio and we think it would be valuable to explore these tradeoffs in more detail and figure out how to more explicitly include them in the IRP decision making framework. In particular:

- Compared to the clean resource portfolio, Site C has more than double the land footprint, an additional 3,110 ha reservoir, and 123 km of affected stream (Table 6-14, p. 6-39). Because the clean portfolio selected by the optimizers includes municipal solid waste generation, the selected portfolio has a greater GHG footprint than Site C (217,000 tonnes CO_2e/yr); though this could be reduced by prioritizing low-emissions or carbon neutral resources.
- While Site C would offer 30 percent more jobs during the seven year construction period, the clean energy portfolio is estimated to offer 13 times more jobs for operation of the facilities, thus offering real opportunities for long term economic development in rural areas (table 6-15, p. 6-40).
- And as discussed earlier, the clean portfolio offers the significant advantage of being adjustable throughout the planning period, thus diminishing the risk of stranded assets and managing the possibility of further rate increases.

9. **Expedite permitting for additional renewable energy projects:** We would not want a delay in Site C or other renewable energy projects to translate into increased pressure to build natural gas-fired generators in the province because they are deemed to be the only option that can be deployed quickly enough to meet demand. To mitigate against this risk and keep options open, we recommend moving ahead with permitting work for additional renewable energy generation projects such that they can be deployed on a faster timeline if needed. This would necessitate some sort of additional relationship with independent power producers that would reserve BC Hydro's right to access the power at a certain price, while also giving the producer the financial certainty to move forward with the permitting steps that aren't typically completed until an electricity purchase agreement is in place.

10. **Test approaches to better integrate non-financial factors into future IRPs:** The efforts to characterize environmental attributes in this IRP represent a notable improvement from past BC Hydro planning processes. They still leave much to be desired, however, because although the characterization has become much more sophisticated, there is still limited ability to incorporate the information into the analysis in a material way. Making progress on this challenge should be a priority post-IRP approval so that possible approaches can be developed and reviewed prior to the start of the next IRP.

    One approach would be to estimate the non-financial costs for resource options in the same way that BC Hydro pioneered efforts to include GHG costs several years ago. Estimating other environmental costs is admittedly a challenge, but that is not a good reason to avoid the issue because by avoiding it, the current approach is akin to saying those environmental attributes (beyond GHGs) do not have a value, which is clearly not the case in reality.

TAC Process

The following four recommendations relate to the TAC process itself and are for consideration for future IRPs or other BC Hydro planning processes.

11. **Form an ongoing resource planning advisory committee:** as we have discussed, the electricity landscape is shifting rapidly, and BC Hydro should cultivate a capacity to adjust its plan on a more ongoing basis. Regular engagement with stakeholders on issues of resource planning would provide a forum to address changes as they occur, get diverse perspectives on possible paths forward, and build relationships that allow participants to engage each other with trust and clarify areas of consensus. The existing Energy Efficiency and Conservation committee is a successful model that could inspire such a committee.

12. **Increase the effort to find consensus within the TAC:** The TAC's terms of reference made space to actively explore possible areas of consensus, but this option was not attempted through the process. While it is hard to predict if consensus would have been possible given the range of perspectives represented on the TAC, it would have been worth the effort to try. The potential value in this exercise is that BC Hydro may be able to find areas where there is explicit support (or opposition) across a range of interests and it allows those parties to directly seek compromises.

13. **Use an external facilitator:** While the BC Hydro staff tasked with facilitating the TAC did a good job, our perspective is that the overall process would be more effective with an external facilitator (an approach used by BC Hydro for other processes such as the EC&E committee). Given that BC Hydro was also a participant in the discussions, a facilitator from an organization not affiliated with any of the participants would likely have helped advance the TAC discussions and improve the quality of advice to BC Hydro.

14. **Increase participant funding:** The participant funding made available to TAC members was adequate to prepare for meetings and participate in those meetings. Pembina appreciates this support, and encourages BC Hydro to continue making participant funding available for future processes. In the interests of supporting well thought through advice from the TAC, we would also recommend that BC Hydro make additional participant funding available to acknowledge the time requirements involved in developing advice to BC Hydro outside of TAC meetings. There were five instances in which BC Hydro solicited TAC input in addition to advice provided during meetings and funding was not available for these contributions.

WRITTEN SUBMISSION FROM:

ASSOCIATION OF MAJOR POWER CUSTOMERS OF BRITISH COLUMBIA

Association of Major Power Customers of BC

October 18, 2013

By E-Mail

Integrated Resource Planning
BC Hydro
Vancouver, BC

Re: Comments on BC Hydro's Integrated Resource Plan

We write to provide BC Hydro with the Association of Major Power Customers of BC's (AMPC) comments on BC Hydro's 2013 Integrated Resource Plan (IRP).

AMPC represents large industrial customers of BC Hydro, customers whose international competitiveness depends in significant part on BC Hydro's efficiency and ability to deliver reliable low cost power now and in the future. AMPC believes that BC Hydro's ability to do so depends in the first instance on the quality of its planning processes to openly evaluate and discuss all options, their costs and impacts.

The IRP is a 20 year plan that is only intended to be reviewed every five years. It is binding on the BC Utilities Commission. Accordingly, it will be relied on heavily and must be thorough, considering a full range of options, and as objective as possible. Government and stakeholders need to understand the ramifications of the decisions being made both today and tomorrow as best they can. Failing to consider a broad range of alternatives because some look unattractive today, and failing to objectively assess where we are today because those assessments may make some uncomfortable about past decisions, helps no-one and is certain to lead to future mistakes. Unfortunately, AMPC considers that the current IRP contains both these failings.

AMPC is of the view that the current IRP has several key flaws which necessitate that it be reformulated before it is submitted to the Government. The risks of proceeding with limited input and scenarios restricted by current policies alone are now becoming clear in BC, where we now face a surplus of high cost generation ($80 – 130) combined with low price markets ($25 -$35) for that surplus, and in Ontario where the government's future is uncertain due in large part to the cost consequences of government interference in energy planning. The IRP should be an exercise in looking forward towards a number of possible future policy and economic environments, and providing as much useful information to the Government as possible. If this is done the government can formulate policy in a changing world based on a good understanding of the full spectrum of facts and potential resulting options.

This IRP comes at a critical time in BC's Hydro's history. BC Hydro's rates are increasing at 4-6 times the rate of inflation, and will continue to do so unless something beyond the IRP is done to address the problems. If these rate increases continue they will have significant ramifications for the economy of BC, and BC Hydro will not have done stakeholders any favors by not fully assessing where we are and what the cost of the choices we make today are.

AMPC believes that in spite of all the good work that has gone into it this IRP, it is seriously flawed and compromised because:

- The consultation the IRP relies upon was limited in scope and dated, in that the consultation that was undertaken largely concerned a prior plan materially different than this one.
- The IRP does not disclose its likely long term rate impacts, even though the BC Utilities Commission commented on the importance of such information in similar circumstances in a May 2007 BC Hydro Decision. Such information is essential for all stakeholders to understand the impacts of the plan. Accurate rate impact information is also necessary to develop credible load forecasts that support the need and timing of any resource additions.
- The IRP does not adequately recognize the gravity of the current surplus and the need not to repeat or exacerbate the underlying problems. While the IRP cuts back in some areas, it does not adequately model or consider options that might help further. For example, additional reductions to independent power producer (IPP) purchases, the unconstrained use of natural gas, and additional reductions to DSM and/or the suspension of Site C work.

The balance of this letter discusses each of these matters in turn.

Consultation

Much is made of the degree of consultation that has gone on since the last IRP. It is true that there has been significant consultation, but it must be recognized that consultation has been restricted in substance, scope and time.

AMPC believes that meaningful consultation requires that informed stakeholders understand the choices that are being made and their impacts on the stakeholders. In this case neither was possible. Key topics such as rate impacts and the use of natural gas for generation beyond the Clean Energy Act restrictions were "off limits". The refusal to deal with subjects that stakeholders consider important limits the value and effectiveness of the consultation. Stakeholders simply need to know what the cost of a plan is. If the cost is low, and the trade-offs limited stakeholders may well be content with a plan as presented. If the cost is high, as AMPC believes this plan is, then stakeholders including policy makers need to be properly informed as to what the trade-offs are and their cost.

The consultation process was suspended for a significant period while the Government considered its position on LNG and other changes, such as the developing surplus that had become apparent in the last year. During the suspension BC Hydro's IRP evolved substantially into what was essentially a new plan. Consultation on that new plan was limited to a one-day workshop and follow-up comments by stakeholders. In AMPC's view this is not meaningful consultation.

Rate Impact and Economic Development

One of the most important aspects dealt with in any Integrated Plan is "what will the impacts be?" As noted above, trade-offs that may be acceptable in a low impact plan may not be acceptable in a high impact one. Yet BC Hydro is completely silent on this issue. One can only assume that is because it does not want to tell stakeholders what is coming.

Rate impacts are also important because they provide a real world foundation from which to judge assumptions, such as forecast load growth and elasticity effects. AMPC is concerned that Industrial rates have been rising faster in BC than in other jurisdictions where many of their competitors are located. The rate increases in the range of 26% over 2 years mentioned in the leaked Working Group Paper have raised industrial customers' concerns about their future competitiveness, and in some cases survival, to new heights. AMPC believes that if increases continue as they have, and as AMPC predicts (9 – 10% average per year for 10 years), and as has been leaked (26% over 2 years), anticipated loads will not materialize. Not only will the elasticity factors used in the load forecasts be out, they will be badly out, as at a certain price the decision to continue operations becomes binary and companies cease to operate, not just use a little less electricity. BC Hydro is planning to spend billions of dollars based on having these loads in place and these forecasts must be as accurate and transparent as possible.

The necessity for BC Hydro to provide long term rate forecasts, and the reasonableness of doing so, was addressed by the BCUC in its May 11, 2007 Decision concerning BC Hydro's Integrated Electricity Plan and Long Term Acquisition Plan (the predecessors to the IRP). The Commission said the following at p. 154:

> *<u>The Commission Panel is concerned that BC Hydro has not studied the trajectory of its own retail rates in real terms. The Commission Panel notes the considerable efforts made in forecasting wholesale electricity prices and natural gas prices.</u> The Commission Panel notes the evidence on negative margin which will increase the pressure on BC Hydro's rates, as will any significant investments in plant and equipment.* ***Therefore, the Commission Panel directs BC Hydro to file a report containing, among other things, a financial forecast of BC Hydro's rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. Input assumptions should be summarized in a concise, but comprehensive manner.***
> [underlining added for emphasis, bold in original]

There can be no excuse for the absence of this information in this IRP, particularly when so much less important information is provided. Stakeholders will not have confidence in BC Hydro's load forecast or believe that its IRP is in their best interest without this information.

BC Hydro's Response to the Surplus Supply Situation

The forecast surplus is having a substantial effect on customers and the situation is likely to get worse before it gets better. BC Hydro has more resources under contract than it needs or can profitably sell. It is buying firm electricity under recent contracts with IPPs for $85 – 135/MWh and selling it for $25 – 35/MWh. Cumulatively the impact of these sales is transferring hundreds of millions of dollars per year from BC Customers to IPPs. For example Table 4.2 from BC Hydro's IRP shows a surplus after DSM for 2017 of 6,913 GWh. If this power is bought at $100/MWh and sold into power markets for $30/MWh, both conservative assumptions, the loss to ratepayers in that year will be $483.9 Million. In other words, customers' rates could have been reduced by half a billion dollars or about 12% if BC Hydro was not committed to purchase that much power at such high prices. That half billion dollars clearly affects the overall BC economy and BC's relative competitiveness for industry. It needs to be mitigated.

While BC Hydro has taken some steps to reduce IPP purchases from some IPPs who have failed to make contractual commitments, BC Hydro can and must do more in rearranging its supply plans, both IPP and internal, in recognition of the harm rapidly rising rates are doing to customers. Reading the IRP leads one to believe BC Hydro recognizes the crisis it is facing in terms of rates, but still wants to do something for everyone, just a little bit less than in the past. As long as customers are paying the resulting costs this is not acceptable. Some additional things BC Hydro could do include:

- Cancel all IPP contracts where IPPs have failed to meet, or will not meet, their obligations within a reasonable time period.
- Model the use of natural gas unconstrained by the Clean Energy Act. It is important to know how much the Clean Energy Act's limits on natural gas use are costing customers so that a rational debate can be held on whether or not policy changes should be made now, or in the future.
- Revisit DSM and ensure it is the least cost-effective DSM programs that are being curtailed. DSM cost effectiveness should be established by technical experts based on sound data clearly stating the rate impacts, and not the use of untested regulations.
- Revisit the timing of and need for Site C. It is clear that if BC Hydro undertakes its proposed DSM programs Site C's timing is premature. Customers should not simultaneously pay for (i) DSM to avoid new supply side resources, and (ii) the very new supply side resources that are supposed to be avoided by DSM. Furthermore, as the total cost for Site C approaches $8 Billion, the desirability of getting involved in a mega project of this nature, with its long lead times and high cost risks, do not look as attractive as they once may have. BC Hydro and the Government should take advantage of the additional time the surplus has provided to re-evaluate the prudence of proceeding further with this project in a time of uncertain load forecasts.

Conclusion

This IRP is a critical policy document going forward, as it is caught up in the tension between the world that the Clean Energy Act contemplated and the reality of the energy market that has resulted due to subsequent global economic challenges, a low cost natural gas revolution, and changing energy policies in neighbouring jurisdictions. It is critical that the IRP include an assessment of its full impact on customers, and an open view of all the generation options available to BC Hydro so that BC Hydro customers and taxpayers can appreciate the risk, cost, and value of policy choices and their alternatives.

Yours very truly,

(original signed by R.B. Wallace for R. Stout)

Richard Stout

WRITTEN SUBMISSION FROM:

ASSOCIATION OF MAJOR POWER CUSTOMERS OF BRITISH COLUMBIA

ATTACHMENT

INSTITUT C.D. HOWE INSTITUTE

COMMENTARY

NO. 389

A New Blueprint for Ontario's Electricity Market

Ontario can more cost-effectively meet its electricity needs and environmental objectives by returning to reliance on a well-designed market, with truly independent institutions and long-term price signals for new capacity on a technology-neutral basis.

A.J. Goulding

November 2013

The Institute's Commitment to Quality

About The Author

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The Study In Brief

An ongoing challenge for power markets worldwide is to assure sufficient continued investment to maintain reliability. A properly designed capacity market – in which plants receive payment for available supply capacity whether or not the power generator runs – may enable Ontario to increase reliance on market signals for new investment. To be effective, the government must pair building a capacity market with several changes in the role and function of existing Ontario power market institutions. The government should isolate policymakers from implementation agencies.

The Ontario power sector today has oversupply, a mismatch of generator capabilities and needs, rising prices to final consumers, a lack of transparency in prices, and volatile and contradictory policies. Consequently, private-sector actors are unable to justify investment without some form of government-backed contract. The government's failure to rely on either sound planning or market principles has meant that the province has not procured generation capacity at a long-run least cost.

Current surplus supply conditions provide a window for thoughtful policy review. The government should establish a market that sends transparent and effective price signals of the need for new electricity generation capacity. Doing so first requires creating appropriate buffers between implementation entities and policymakers, meaning that the government should not use ministerial directives to interfere with the day-to-day operation of key power sector institutions. It also requires that the province replace the Ontario Power Authority's principal buyer role with newly created supply entities.

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Ontario's electricity system operates on a framework constructed haphazardly to satisfy often-contradictory public policy goals. The result is a litany of inefficiencies.

The province's power sector today has an electricity oversupply, a mismatch between generator capabilities and supply needs, rising prices for final consumers and a lack of cost transparency, along with a record of volatile, often contradictory, policies. Consequently, private-sector electricity generators are unable to justify investment in the system without some form of government-backed contract.

While various provincial governments have announced laudable goals over the years, their failure to implement either sound planning or rely on market principles has meant that Ontarians are not getting electricity at the lowest possible cost. Projections suggest that Ontario residents and businesses will be paying substantially higher electrical bills over the next decade than if the provincial electricity system had instead relied on combined cycle natural gas turbine electricity generation,[1] even when the potential costs of buying greenhouse gas emissions credits are taken into account. As well, Ontario's Feed-in Tariff program, under which the province has contracted for extensive wind and solar power for some years into the future, will increase generation and transmission costs, further hiking electricity prices.

Meanwhile, the development of low-cost shale gas in North America has meant that the economics of natural gas-fired electricity plants, and combined cycle plants in particular, have changed dramatically. The province should redesign its electricity generation procurement to incorporate market signals that would attract long term least-cost generation sources while avoiding the procurement mistakes of the past.

In future, Ontario's electricity generation procurement should become technologically neutral to ensure that the province builds the most cost-effective, environmentally compliant generation assets. The province should accompany this procurement policy shift with changes in the role of existing Ontario power market institutions, as well as a framework to isolate policymakers from implementation agencies. History has proven that unless institutions are autonomous, politicians often succumb to the temptation to circumvent electricity sector policymaking processes.

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Mr. Goulding advises a range of public and private clients in Ontario on issues associated with market design, asset valuation, and regulatory economics. Calculations produced for the purposes of this paper are purely illustrative; additional analysis would be required for any such calculations to be cited in legal or regulatory proceedings. Given the conceptual nature of this paper, discussions of individual elements are not intended to be comprehensive or exhaustive. Findings in this paper should in no way be construed as suggesting that the author supports the establishment of capacity markets in all jurisdictions or under any circumstances.

1 Combined cycle natural gas-fired turbine electricity generation combines a natural gas-fired electricity-generating turbine (the first stage) with the exhaust heat used to create steam to power a second electricity-generating turbine.

Establishing an Ontario capacity market would enable the province to increase reliance on market signals for new investment. To be efficient, this market would need an appropriate number of sellers and buyers. An important step in creating more of these counterparties is to increase the number of entities with a direct responsibility for serving the end customers. Such load-serving entities would be responsible for providing customers with the commodity portion of their load, as distinct from its transportation of it.

Currently, Ontario's Feed-in Tariff program and nuclear power programs serve narrow policy objectives, which have made their underlying generation assets more expensive than natural gas, even if a substantial price is placed on greenhouse gas emissions. To address greenhouse gas concerns, the most sensible answer is a North American cap-and-trade mechanism, which would yield additional revenue for the province through emission credit auctions.

Ontario's principal buyer-based capacity procurement is neither a planned nor a market approach, though it inflicts the worst aspects of both on ratepayers. It has resulted not only in cost impacts for the province's consumers, favouring generation technologies that don't necessarily produce the most efficient reductions in greenhouse gas emissions, but also in a surplus of generation capacity. Policymakers should capitalize on this period of surplus as it offers the government a window for thoughtful policy review.

Part 1: Problems with the Status Quo

Ontario's approach to power sector investment and planning is inefficient, expensive and arguably unsustainable. Investment decisions reflect neither market signals nor long-term, centralized, utility-style system plans. The government is using the electricity sector to support a range of shifting policy objectives, including job creation, sector-specific economic growth and emissions reduction, without credible examination of whether burdening the electricity ratepayer with the cost of such initiatives is economically efficient.

As well, Ontario has failed to insulate electricity institutions (see Box 1) from ad hoc policy changes, which have proven costly to consumers while undermining democratic principles of openness and public participation. No political party has a monopoly on political interference in the power sector in Ontario. All have engaged in ill-considered price freezes and reductions, sudden policy shifts and stopgap solutions.

The Costs of Today's Electricity System

While often characterized as "hybrid," Ontario's electricity market largely consists of a principal buyer, the Ontario Power Authority (OPA), whose decisions are heavily influenced by the provincial government. Investors have been wary about building generation capacity without an OPA contract.

Despite limited or negative electricity demand growth over the past five years (2007-2011 inclusive), averaging minus 1.1 percent per year, Ontario's installed capacity has grown over the same period by 1.8 percent annually. While a portion of this capacity increase has been justified by the decision to close all of Ontario's coal-fired power stations, current policies could result in excess supply relative to peak demand through 2019 (Figure 2).[2]

2 The graphic shows only capacity currently under contract; it does not account for further capacity to be added under the ongoing FIT program.

Box 1: Current Ontario Electricity Market Arrangements

The provincially owned Ontario Power Generation (OPG) is the province's dominant electricity supplier, with its nuclear and hydroelectric rate-regulated (also known as "prescribed") power plants providing nearly one-half of Ontario's power output (Figure 1). OPG's role, however, has diminished recently as the Ontario Power Authority (OPA), which has overall responsibility for ensuring the province's long-term electricity supply, contracted with new entrants such as solar and wind power producers using a Feed-in Tariff (FIT). OPG also has some unregulated power generating assets that operate on a merchant basis. Bruce Power operates the Bruce Nuclear Generating Station, leased from OPG, with a generating contract with the OPA. The Ontario Electricity Financial Corporation (OEFC) holds contracts with private generators built before the dissolution of Ontario Hydro.

Although OPA nominally bases its contracting decisions on its Long-term Energy Plan (LTEP), provisions of the Ontario *Green Energy Act* (GEA) and subsequent ministerial directives have overridden the LTEP. In spring 2013, the Ontario Minister of Energy announced a formal LTEP review to update long-term supply and demand forecasts, focusing on diversity of supply mix, conservation and creation of a predictable and sustainable clean-energy procurement process.

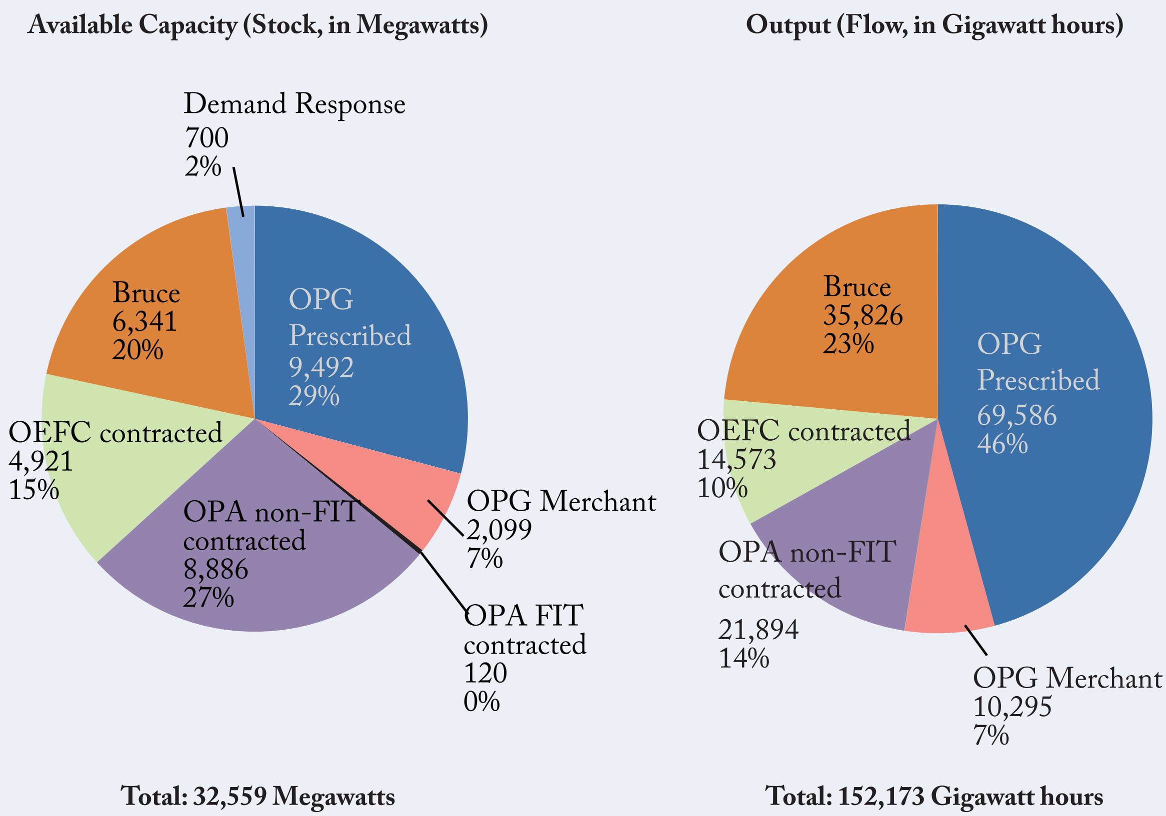
The Ontario Independent Electricity System Operator (IESO) coordinates dispatch and transmission flows and operates spot markets. The Ontario Energy Board (OEB) regulates a portion of OPG's generation capacity, but otherwise has limited oversight of generation markets and the OPA.

A large portion of wholesale energy costs are recouped through the Global Adjustment (GA). The GA is paid by electricity consumers, and was established as a so-called Provincial Benefit, separate from the Debt Retirement Charge (DRC). The DRC consists mainly of payments on outstanding Ontario Hydro debt that successor companies were unable to absorb. With the OPA's creation, the GA came to include the costs of OPA contracts that it cannot recover through market revenues. In 2012, more than one-half (54 percent) of the cost of the GA was comprised of OPA charges on contracts for generators and suppliers of conservation services, while charges on OPG's nuclear and baseload hydroelectric generation (29 percent) and the contracts held by the OEFC (17 percent) made up the remainder (IESO N.D.). Changes in IESO prices and the level of the Global Adjustment are largely symmetrical because, in order to fulfill the terms of the contracts it holds that guarantee generators a certain amount of revenue, OPA payments to generators fall, or become negative, as IESO prices approach or exceed the contract price.

Under the *Ontario Energy Board Act*, the OEB can review only OPA activities related to conservation targets and payments to and from distributors, retailers or the IESO. The OPA is required to assist the OEB by facilitating stability in rates for certain types of customers and provide information relating to medium- and long-term electricity needs, as well as the adequacy and reliability of the province's power systems. OEB also approves OPA's electricity procurement process and its annual fees.

The total cost of electricity for Ontario consumers is the sum of the Hourly Ontario Electricity Price (HOEP) and the Global Adjustment (GA). It is useful to examine this total cost from two perspectives: first, in comparison with adjacent markets over the recent past, and in comparison with the future projected all-in cost of a new, generic natural gas-fired combined cycle gas turbine (CCGT). Total energy costs to Ontario consumers have been higher than those in neighbouring western New York state despite falling natural gas prices in both jurisdictions (Figure 3).

Figure 1: 2012 Ontario Available Capacity and Output by Asset Type



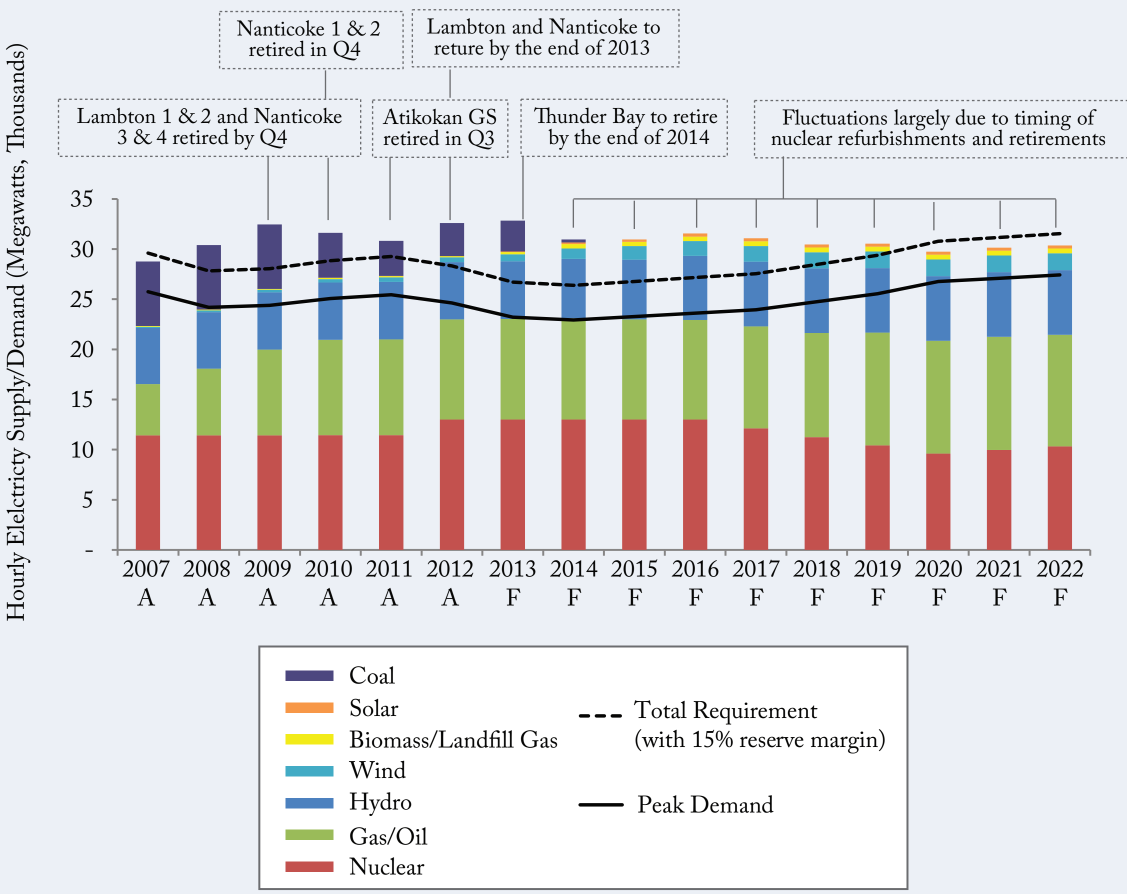
Note: Wind capacity is derated to 23.5% of installed capacity (average of 13.4% in summer and 33.6% in winter), and capacity for solar is de-rated to 20% (average of 40% in summer and 0% in winter), as reported in NERC (2011). Capacity for hydroelectric resources is de-rated to 72% (average of 67% and 77% range of contribution factors used by IESO 2012a). As of December 31, 2012, OPA reports 501 MW of in-service FIT and micro FIT capacity (solar, wind and biomass) which, after applying de-rates, translates into 120 MW of available capacity.

Sources: London Economics International (LEI) calculations from Energy Velocity commercial database; OPA (2012a,b); and IESO (2012a,b).

Cost Impacts

Natural gas plants serve as the price-setting electricity generator in most North American electricity markets. Western New York's all-in prices are more rapidly allowing customers to benefit from declines in natural gas prices, while Ontario's all-in prices are not. Looking forward, projections suggest that Ontario will be paying substantially more over the next decade than the cost of a combined cycle gas turbine that provides baseload power, even when taking into account carbon costs (Figure 4). In other words, had different policies been pursued, Ontario could have had both low-emission electricity – relative to coal power – and lower prices than currently prevail by allowing natural gas to play an even more prominent role in Ontario's fuel mix.

Figure 2: Ontario Supply-demand Balance 2007 to 2022



Notes: A: Actual data. F: Forecast. Calculations include the expected additional capacity currently under contract. Capacity for wind, solar and hydroelectric resources treated in the same fashion as for Figure 1. OPA contracted supply is as of December 31, 2012. OPA reports 2,019 MW in-service wind capacity and 3,772 MW under construction expected to come online by the end of 2015; with de-rate factor of 23.5 percent this translates into 474 MW in 2012 and 887 MW of additional wind by the end of 2015. Figure includes OPA RESOP solar contracts and IESO reported actual capacity. IESO (2012a) suggests average reserve margin target of 18.7 percent, the 15 percent reserve margin assumes that interconnections contribute to reliability. Sources: LEI calculations from IESO historical data; IESO (2012b); OPA (2012a,b,c).

The Ontario power market lacks both the clarity of a disciplined integrated resource plan and the benefits of competitive pressure on generators. In a fully regulated market, the utility would submit a procurement plan to its regulator that would be vetted in an open process. Upon approval, the utility would be charged with implementing the plan at least cost.

As it is, Ministerial directives that OPA secure electricity contracts in particular ways constantly

Figure 3: Five-year Comparison of Ontario Electricity Prices to Western New York Electricity Prices and Natural Gas Prices

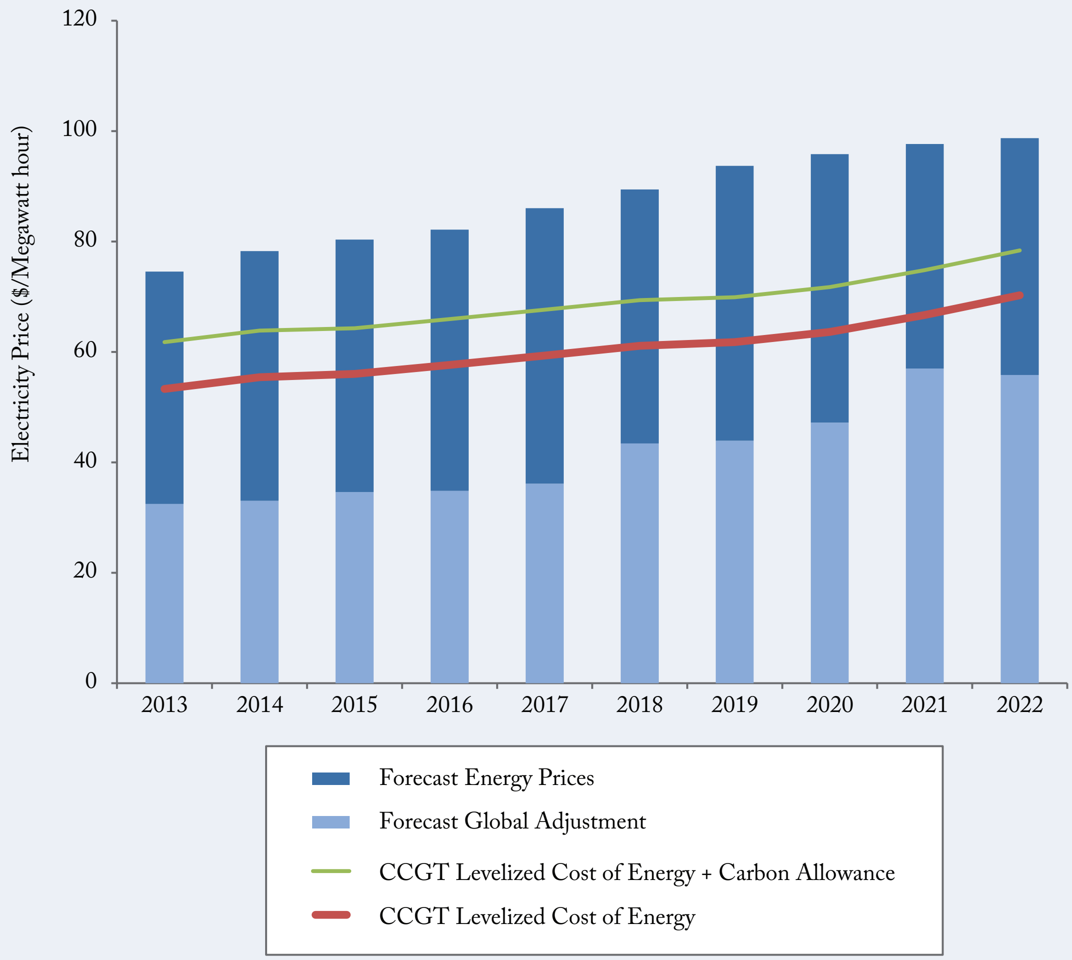
Note: Ontario prices include HOEP and GA. Western New York electricity price includes energy, capacity and System Benefit Charge (the System Benefit Charge pays for various policy initiatives consistent with some aspects of the GEA). Competitive transition charges (CTCs) in Western New York were eliminated in January 2012 and are excluded from the chart; all figures in nominal Canadian dollars, using Bloomberg historical monthly exchange rates. The Dawn Hub price is a standard benchmark of Canadian natural gas prices, the Henry Hub price is a major benchmark for US natural gas prices.

Source: LEI calculations from IESO; OPA; New York Independent System Operator; Bloomberg.

modify previously approved long-term plans.[3] Between 2005 and June 2013, the Minister of Energy issued 66 directives to OPA. Out of these, 36 directed OPA with relation to procurement of power/capacity from OPG or other generators.

3 FIT Program Version 2.0 (effective since Aug. 10, 2012) rules improved on previous arrangements by including a procurement targets provision establishing the maximum amount of MWs procured during an application period; OPA will procure up to 200 MW worth of contracts (the procurement target) during the Small FIT application window (Dec. 14, 2012 – Jan. 18, 2013). An additional 15 MW is set aside for pilot rooftop solar projects (See OPA 2012d, OPA N.D.a, OPA N.D.b and OPA 2012e).

Figure 4: Comparison of Estimated Ontario Electricity Price Levelized Cost of Natural Gas CCGT

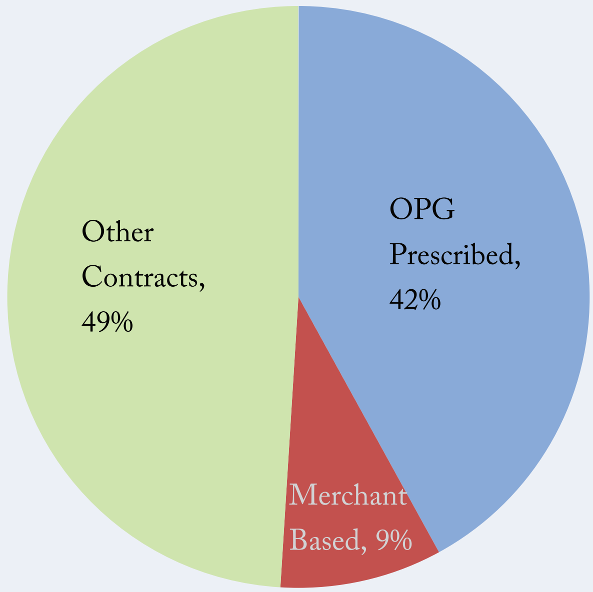


Note: CCGT capacity factor assumed to be 85 percent; gas prices are NYMEX Henry Hub forwards as of mid-October 2012 escalated toward the Energy Information Administration (2012) projected 2020 gas price, plus the 5-year (2007-2011) average differential between annual Henry Hub and Dawn prices; carbon allowance price assumed to be $20/ton; all figures nominal Canadian dollars and assuming exchange rate CA $1/US$. The CCGT capacity factor assumes a unit is added to the system when it is efficient to do so, rather than current actual capacity factors of underutilized existing plants. CCGT capacity factors averaged 26% in Ontario in 2012, according to a commercially-available database. Underutilized gas plants further highlight the extent to which supply and demand have been mis-matched in Ontario.

Sources: LEI calculations from IESO; OPA; EIA.

Meanwhile, the government has banished the word “market” from the Independent Electricity System Operator’s (IESO) name, and 91 percent of the province’s energy production is either under contract to the OPA or rate-regulated by OEB (Figure 5), few plants rely solely on IESO-run markets, because most earn revenue through OPA contracts.

Figure 5: Expected Breakdown of Ontario 2013 Generation Based on Contractual Position



Source: OEB (2013a, p. 21).

Ontario's failure to implement either a planned or a market approach for the power sector has resulted in higher costs for provincial consumers. This failure has also produced a surplus of generation capacity, with Ontario consumers liable to pay an additional $42 million to $370 million per year beyond what is required to meet a 15 percent reserve margin between 2013 and 2015.[4] The actual costs to Ontario consumers may be end up being higher than $370 million, given that the OPA has reported significantly higher capacity costs for recently constructed plants.[5]

Similarly, the Auditor General of Ontario has stated that the FIT program causes higher prices and added about $4.4 billion in costs over its 20-year contract terms compared to what would have been incurred under the previous, less-generous Renewable Energy Standard Offer Program. (Office of the Auditor General of Ontario 2011). The FIT program offered guaranteed prices for renewable projects under 10 MW until Ontario's Ministry of Energy put the program under review.

Other costs resulting from failure to implement a planned or a market approach include an estimated

4 The cost estimate for additional reserves is based on the average net revenue requirement of the clean energy supply conventional gas-fired contracts signed by OPA ($7,900 per MW-month) (OEB 2013a, p .17).

5 The new Napanee Generating Station gas-fired plant will receive at least $15,200 per MW of installed capacity each month, regardless of output (OPA 2012f).

additional $900 million to move gas-fired plants out of Oakville and Mississauga and $28 million to convert OPG's Thunder Bay Generating Station from coal to gas after spending $190 million on its construction (Legislative Assembly of Ontario 2013).

Furthermore, the ministerial-directed conversion of the Atikokan coal-fired plant into a biomass-fired operation will cost $170 million. The plant will have a levelized cost of more than twice that of a combined cycle natural gas plant (see Appendix for calculation and OPG N.D.).

Politicization of Power Sector Investment Decisions

Power sector investments are capital-intensive and long-lived. A lack of constancy in power sector policies reduces the willingness of private investors to participate. Government intervention becomes self-perpetuating, as the province replaces (directly through OPG or indirectly through OPA) private risk-taking capital. Without proper safeguards, this transfer of risk from private investors to ratepayers and/or taxpayers can result in inefficient capital allocations, as governments stray from commercial objectives and apply artificially low hurdle rates to specific projects, if they apply a hurdle rate at all.

Furthermore, the electricity sector can become a convenient instrument for policy implementation, regardless of the corresponding economic merits or lack thereof. Given the mismatch between short-run political horizons (four to six years) and long-run, least-cost planning (10 to 20 years), it is critical to have appropriate safeguards in place to prevent election-driven policy volatility.

A properly functioning power sector policy framework begins with government setting broad objectives, which are then implemented through independent institutions and market mechanisms. It does not involve, as has too often been the case in Ontario, the government issuing directives for specific actions without thoughtful analysis and transparent deliberation. The most appropriate policy objective for the power sector is to meet the reliability expectations of the average customer at long run, least cost within prevailing environmental regulations.

Unless institutions are truly autonomous, many politicians are unable to resist the temptation to circumvent electricity-sector policymaking processes. Autonomy from government does not mean being exempt from government oversight, but it does mean that qualified executives and boards are allowed to organize their activities consistent with clear mandates and are free from unscheduled interventions by policymakers.

The first way to establish electricity market independence is to ensure the independence of board members and revenue streams. Board independence is a necessary but not sufficient precondition for institutional independence – the entities need also to have dedicated funding streams that are not subject to the whims of the legislature.[6] Neighboring US states protect the independence of key institutions with defined terms of office for board members and require that the board not be solely in the hands of one political party. Board member terms need to be staggered, and removal only based on a limited number of conditions such as criminal activity or mental instability (Table 1).

6 The OEB is funded by fees, assessments and administrative penalties it collects from regulated entities (OEB 2010, Article 13.3). For its part, the OPA's operating budget is funded by fees on electricity consumers ($0.551/MWh) and registration fees on OPA procurements (OPA 2013, page 10).

Table 1: Comparison of Board Selection Criteria in Ontario, New York, and Michigan

Body	Ontario Energy Board	Ontario Power Authority	Ontario Energy Financial Corporation	New York State Public Service Commission	Michigan Public Service Commission
Number of members	At least five (currently 6 full time, 4 part time)	11	At least 2 and not more than 12 directors (currently 8)	5	3
Appointed by	The Lieutenant Governor in Council. In practice, nominated by the Minster of Energy	Minister of Energy	Appointed by the Lieutenant Governor in Council and is accountable to the Minister of Finance	Governor	Governor
Confirmation required?	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Subject to review by Standing Committee on Government Agencies	Confirmation by Senate	Consent of the Senate
Nomination committee?	No	Self nomination if there is vacancy	No	Yes, governor cannot reject nomination list twice	No
Limitation on political parties?	No	No	No	No more than 3 members may represent the same political party	No more than two Commissioners may represent the same political party
Explicit qualitifaction requirement?	No	No	No, the current Board is largely comprised of public servants employed by the Crown	Yes, education and training and 3 or more years of experience in fields of economics, engineering, law, accounting, etc.	None
Term	First term shall not exceed 2 years, may be reappointed for one or more terms of office, each of which does not exceed 5 years	Hold office at pleasure for initial term not exceeding two years and may be reappointed for successive terms not exceeding five years each	Hold office at pleasure for a term not exceeding 3 years and may be reappointed for successive terms not exceeding 3 years each	6 years	Staggered 6 years term

Sources: State and provincial laws and regulations.

The second independence measure is government divestiture of its remaining electricity assets owned by OPG, such as an "inclusive privatization" involving pension funds, unions and community or social organizations in the shareholding structure.[7] The outcome is that the resulting entities focus on achieving commercial objectives within a broad policy framework applicable to all such companies.

Challenges with the Global Adjustment

The GA obscures the costs of market interventions and interferes with economically efficient decision making in several ways. It distorts price signals: customers see the GA assessment only after they have made their consumption decisions. The GA, therefore, directly undercuts consumer efforts to save money by altering their demand levels and patterns because any resulting declines in wholesale revenue are offset by reciprocal increases in the GA.

The GA also makes consumer bills less comprehensible, potentially undermining consumer acceptance of power sector policies. Programs for large users serve to further mute price signals to these customer classes and blunt the incentive for companies to seek contracts on their own. The GA co-mingles costs to achieve environmental objectives with those related to reliability goals. Finally, this lack of transparency can lead to policymakers hiding the consequences of poor decisions.

By working to eliminate the GA, Ontario could improve the fidelity of the price signal to final consumers. Among other benefits, this would reduce the yo-yo effect of suppressing wholesale prices on one hand, and thereby potentially increasing demand, and on the other hand spending on programs that encourage consumers to alter their usage patterns. Such consumer programs, also known as demand-side management, work best when customers' power charges are comprehensive and transparent.

Why a Capacity Market is Appropriate for Ontario

One way to reintroduce market discipline to the Ontario electricity sector would be to introduce a capacity market. North American wholesale electricity markets have evolved in one of two ways: energy-only markets, such as Alberta and the Electric Reliability Council of Texas, or capacity markets. In an energy-only market, participant revenues are determined either by spot market activity or by bilateral contract positions.

For energy-only markets to work properly, policymakers must allow them to reach peak prices, which reflect a scarcity value, to provide price signals to new entrants. Competitive wholesale markets with price caps, particularly when those price caps are significantly below the level of economic losses caused by an outage, may fail to provide such signals. When allowed to operate smoothly, energy-only markets can be the most economically efficient design for competitive wholesale electricity markets. However, an energy-only market in Ontario might be greeted with skepticism by investors, given the province's history of suppressing price signals.

Capacity markets provide an additional revenue stream from "capacity" payments – a payment that a plant receives for available supply even if it is not dispatched, provided that it is able to produce electricity, if required. US capacity markets (Table 2)

7 The shareholder arrangements for Bruce Power (a partnership among Cameco Corp., TransCanada Corp., the Power Workers' Union, the Society of Energy Professionals and indirectly the Ontario Municipal Employees Retirement System) present a model for incorporating private capital into OPG or its divisions.

Table 2: Selected ISO Capacity Market Designs

ISO	Capacity market design summary
California	• Spot capacity market, serves 1 state, since 2004* • No centralized capacity market currently in place; system-wide Resource Adequacy Requirement ("RAR") and local RAR satisfied by utilities/LSEs on annual and monthly basis through bilateral trading of capacity • LSEs issue long-term requests for proposals and their longer-term procurement plans
New England	• Forward capacity market, serves 6 states, since 2006 • Use of 3-year forwards via Forward Capacity Auction with annual reconfiguration auctions • Local requirement for import constrained areas; with commitment period start, LSEs and generators can also participate in seasonal and monthly reconfiguration auctions
Midcontinent	• Voluntary capacity market, serves 11 states, since 2009 • LSE are required to buy from supply resources (which participate) in order to comply with the resource adequacy requirement in their zones
New York	• Spot capacity market, serves 1 state, since 1999 • Monthly Installed Capacity Spot Market Auction • LSEs with unmet resource adequacy obliged to purchase capacity and offer excess capacity
PJM (Northeast US)	• Forward capacity market, serves 13 states and District of Columbia, since 2007 • 3-year ahead Forward Capacity Market that relies on a downward sloping demand curve • LSEs can use self-supply and bilateral contracts and residual capacity procured in competitive auction

Note: *CAISO System RAR instituted in 2004 and Local RAR in 2006.

Sources: various ISOs.

exist in California (CA-ISO), New England (ISO-NE), the Midwest (MISO), New York (NYISO) and PJM, which serves all or part of 13 states between Illinois and New Jersey (PJM). Capacity markets provide an additional means of signaling when the market needs new generation capacity. One of the key motivations for implementing capacity markets has been to replace the so-called "missing-money" problem that arises when governments and regulators seek to suppress peak prices, for example through price caps.

Capacity markets have faced several challenges. In their initial designs, capacity prices were not known more than a year in advance, meaning developers needed to forecast future prices and convince their financers to consider the associated revenue stream in determining the asset's debt-carrying capability. As a result, some capacity markets have been redesigned to allow a three-year forward timeframe.

Capacity markets also tend to be binary – during periods of surplus, capacity is worthless. When scarcity conditions arise, the capacity price increases to a capped price that the system operator sets, usually at the amortized cost of a new simple cycle gas turbine. This amortized cost serves as a proxy for an economic means of meeting peak load. System operators have attempted to address the binary nature of capacity markets through the creation of floor prices and adjusting minimum prices based on reserve margins and bids.

Why the Status Quo Is Not Sustainable

The current Ontario power sector structure is not sustainable. Repeated use of ministerial directives increases uncertainty about policy direction and durability. The FIT program exacerbates imbalances in supply composition and increases costs. Requiring a provincially owned generator to pursue investments for other than purely commercial reasons creates additional cost challenges. Price suppression and distortion through the GA and other means produces inefficient consumption decisions.

As Ontario power costs diverge from those in neighbouring states and provinces, economic activity may suffer. Eventually, the province's credit rating may be at risk if rising prices and falling demand lead to stranded assets coupled with implicitly provincially backed entities.[8] However, Ontario can address all these issues if it focuses on improving price signals, codifying autonomy for provincial electricity institutions and deploying long-run, least-cost approaches to meeting stated policy objectives. Recent initiatives suggest the government is seeking to address these challenges in an economically rational fashion. However, broader reforms are still necessary.

Part 2: Creating a Meaningful Long-term Price Signal for Power in Ontario

The Ontario power sector already contains the necessary building blocks to create a stable long-term investment climate. Instead of replacing (or merging) existing institutions, policymakers should refocus them on long-run economic efficiency, including providing effective and transparent price signals. Obscuring price signals ultimately reduces social welfare by leading to a misallocation of resources.

Providing Appropriate Price Signals and Reallocating Risk

In the late 1990s, the province began to create a more dynamic and innovative power sector than existed under Ontario Hydro. However, while more power generation participants have entered the market as a result, the number of potential counterparties has remained narrow. The OPA has crowded out private long-term electricity buyers: generating companies have little incentive to seek alternative purchasers and electricity buyers cannot match the credit quality and duration of OPA contracts. These contracts shift operational risks to the developer's shareholders (if the plant fails to operate, the developer does not get paid), along with the risk of cost overruns. Ratepayers, however, bear the risk that OPA will over-contract on their behalf.

Risk allocation becomes awkward when the government directs the OPA to contract with OPG, as such contracts simply shift risk between ratepayers and taxpayers. Failing to subject OPG to the same discipline that private developers face – the need to bid for and win contracts and to stay within expected budgets – means that ratepayers, rather than shareholders, end up paying for cost overruns. Even if OPG did bear the burden of cost overruns, taxpayers would ultimately pay the cost through reduced dividends.

8 While OPG and OPA may be ostensibly arms-length from the provincial government, the spillover effects on the province's credit from allowing either to default makes it unlikely that rating agencies would ignore their liabilities in assessing the province's overall creditworthiness.

By re-orienting the Ontario power sector away from OPA as a principal buyer, the province can reallocate risks and make price signals more transparent, which would improve investment and consumption decisions.[9] Diversifying procurement responsibilities would reduce risks of oversupply. If private companies were on the power purchasing side, their shareholders would face lower profits if the companies over-contract, whereas entities like OPA face limited consequences in similar situations. Indeed, relying solely on private capital for future investment will result in building least-cost generating facilities to meet power supply needs consistent with environmental laws.

Stages of Market Evolution

The province should take six steps to transition the Ontario power market to a durable set of arrangements that would produce long-run, least cost power supplies for consumers.

1. *Strengthen the autonomy of power sector institutions*.
2. *Address the role of nuclear*.
3. *Create load serving entities* required to participate in a resource adequacy market (RAM).
4. *Establish a resource adequacy market*.
5. *Reallocate capacity* (total plant output potential, expressed in MW) and energy (production, which occurs when capacity is called upon, expressed in MWh) from existing OPA contracts to load serving entities (LSEs), with all subsequent contracting driven by LSE perceptions of need relative to their resource adequacy market responsibilities.
6. *Provide customers with default supply options*, which pass through prices from resource adequacy markets (RAMs) and spot markets, with those wishing to hedge able to do so using competitive offerings from LSEs.

Power Sector Autonomy

The first step in setting a proper foundation for power market evolution is to enshrine the independence of key market institutions and clarify their mandates. Once the long-term policy direction for the power sector has been defined, policymakers then need to put distance between themselves and the implementing institutions. In Ontario, the government can assure some measure of independence by insulating OEB, IESO and OPA board members from removal for any reason other than expiration of term, mental incompetence or moral turpitude, and by providing dedicated funding mechanisms for those institutions.

The government should abandon efforts, currently on hold, to merge the OPA and IESO. Due to the difference in functions between the two agencies, savings from the combination are likely illusionary, and the potential for conflict of interest is rife. While the few areas where functions are duplicated should be allocated to one or the other, maintaining the two as separate entities is critical to the integrity of the Ontario power market. Mixing the functions of market and transmission operator with that of contract administration may raise the suspicions of market participants that the combined entity will operate in a fashion that reduces OPA-related costs at the expense of other market participants while undermining the fidelity of the

9 Those who laud the simplicity of an OPA contracting regime should consider the systemic imperative for central procurement entities to over-contract. The consequences for undersupply are felt immediately, while costs of oversupply only become apparent over a long period of time, and possibly after the decision-maker is no longer in the job. The simplicity will prove costly to ratepayers unless the procurement entity and its regulator are arms-length from politicians, and the long-term procurement plans (including the associated target reserve margins) are subjected to full and proper regulatory review.

market price signal. This may drive participants from the market, increasing future investment costs and reducing the diversity of actors.[10]

The government should expand the IESO's mandate to include administration of a long-term capacity market. On the other hand, OPA's mandate should narrow. Originally intended as a transitional agency,[11] OPA was designed to address a looming supply shortfall by providing stability to investors while the Ontario power market steadied. OPA successfully accomplished this.

Through subsequent procurements and FIT, OPA also catalyzed the creation of a local private-sector renewable energy industry. Now that the government has achieved these goals, and once contracts for nuclear refurbishment contracts are in place, it should direct the OPA to cease further contracting, focus on contract renegotiations to reduce the GA and, ultimately, become a pure contracts administrator. The OPA should wind down its conservation programs consistent with a plan to enhance market price signals for efficient demand-side management, while IESO designs demand-response programs consistent with its market operations. The OEB would periodically review the OPA's budget, its progress in reducing the GA and plans for shrinking.

Assessing the Role for Nuclear

Future Ontario power sector investors need to know the government strategy for nuclear energy. Investors will be hesitant to make market-based commitments to new generation investments until the government establishes the future size of Ontario's nuclear fleet. Most new nuclear projects will not be cost competitive with combined cycle gas turbines (CCGT) unless natural gas prices increase significantly and carbon is heavily taxed (Figure 6). While some refurbishment projects may be competitive with new baseload gas-fired plants when environmental externalities are considered, new nuclear is not likely to be cost competitive. Meanwhile, existing nuclear power stations should not be abandoned lightly but, at the same time, nuclear should not be preserved at any cost.

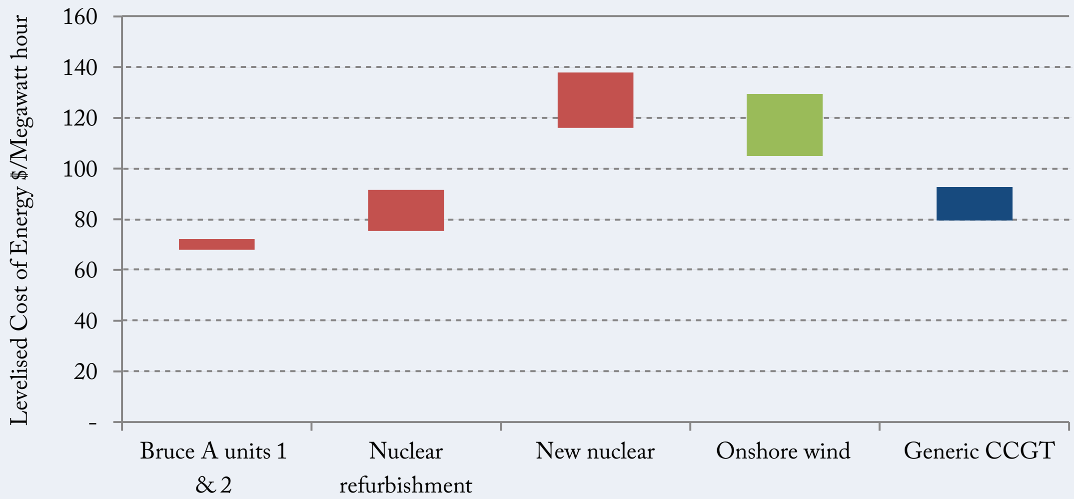
The OPA should hold one final nuclear procurement round based on an announced threshold price and an assessment of the timing of need for baseload resources. The threshold price should be based on the levelized cost of a new CCGT, incorporating an appropriate present value of the cost for carbon and natural gas.[12] In the event that the procurement failed to result in nuclear generators matching the cost of natural gas generators, site owners would be free to redevelop the sites of the proposed nuclear plants as they saw fit (including conversion to gas), but would do so solely on the basis of revenues from spot markets, bilateral contracts and the resource adequacy market described below.

10 More appropriate candidates for merger would be the OPA and OEFC, given that both administer long-term contracts, though OEFC's role will gradually diminish as contracts expire.

11 As Wyman (2008) notes: "Former OPA CEO Jan Carr suggests that the authority should be a "transitional agency" and will at some point "do itself out of a job." Reflecting this view, the OPA's 2007 business plan suggests that, "Over time, as the market develops sufficient ability to ensure timely investment in supply resources, the need for OPA procurement activities will decline."

12 Bid documents should note that no bids above the threshold price would be accepted. While the Ontario market should evolve toward technology-neutral generation investment signals, this final procurement can test the value of the existing nuclear endowment against a natural gas default option. Alternatively, the final procurement round could define the product consistent with what refurbished nuclear plants would be able to supply (baseload power for 20 years commencing approximately five years from the auction date), but allow all technologies to bid.

Figure 6: LCOE* Comparison between Nuclear Refurbishments, New Nuclear, Onshore Wind and Generic CCGT



Notes: * Levelized Cost of Energy.
LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. CCGT LCOE low estimate based on 85% capacity factor, with natural gas prices based on net present value of 20-year forecast prices, a $20/ton carbon price, and EIA (2012) capital cost assumptions. CCGT LCOE high-end estimate based on 70% capacity factor, $7.5/MMBtu gas price, a $20/ton carbon price, and costs based on Ontario-specific cost average. Refurbishment cost of Bruce based on actual announced cost and contract price with OPA. Other nuclear refurbishment costs based on average for Darlington, Gentilly, and Point Lapreau. LCOE of new nuclear based on EIA (2012) assumptions and on average costs of Olkiluoto (Finland) and Flamanville (France) European Pressurized Reactor plants currently under construction. Onshore wind LCOE based on FIT 2.0 price schedule and EIA (2012) assumptions. Weighted average cost of capital ("WACC") for all projects assumed to be 8.88%. See also Appendix A.

Identifying Load Serving Entities

A properly functioning energy market has an appropriate number of sellers and, equally important, buyers. An important step in creating a more robust set of such counterparties is to increase the number of entities with a direct responsibility for purchasing electricity. Such "load serving entities" (LSEs) would be responsible for providing customers with the commodity portion of their load, as distinct from its transportation. An LSE can be a competitive retailer or a utility, but its defining characteristic is that it faces consequences should it fail to provide the energy and capacity contracted by an end-user.[13] LSEs are

13 For the purposes of this *Commentary*, customers directly connected to the transmission system would also be considered to be LSEs, subject to the same rights and obligations as the LSEs created to serve residential customers. Directly connected customers, as well as existing competitive retailers, would face capacity obligations, but would be included in the pro-rata allocation of OPA-contracted capacity described here.

the predominant form of organization to meet load obligations in competitive electricity markets.

Existing electricity local distribution company (LDC) service territories in Ontario are the logical starting point for creation of LSEs. However, Ontario LDCs are regulated businesses of varying size and capabilities that are already facing significant pressure as they seek to upgrade their physical plants and comply with the province's incentive-rate system. This suggests that creation of LSEs within LDCs could prove to be a distraction and may not be effective. As an alternative, the OPA could establish four or five new LSEs for sale by auction to the private sector, with a set of contiguous LDC service territories as boundaries.[14]

The new LSEs would be responsible for procuring energy and capacity on behalf of customers within their initial service territories. However, end customers – business and residential – would be able to choose third-party retailers as their LSEs, and the new LSEs would be eligible to compete in the territories of the other LSEs. The LSEs would be auctioned to experienced commercial companies, accompanied by a pro rata allocation of existing OPA capacity volumes. This pro rata allocation would be further divided proportionally among the LSEs' regulated customers (who have yet to choose a competitive supplier) and competitive customers.[15]

Creating a Resource Adequacy Market

To facilitate the move from Ontario's semi-planned, principal-buyer-based market, Ontario should establish a long-term resource adequacy market (RAM), a form of capacity market. In contrast to energy-only markets, the RAM would require LSEs to procure sufficient capacity (usually denominated in $/kW over a unit of time, such as a month) to meet a target reserve margin. Thus, an LSE would, in addition to procuring sufficient energy to meet its customer's needs, be required to calculate each customer's peak load and procure sufficient capacity to meet that peak load plus a reserve margin. For example, if the customer peak load is 100 MW and the target reserve margin is 15 percent, the required amount of capacity the LSE must purchase is 115 MW (Table 3).

The RAM would be a form of laddered capacity market, with purchase requirements decreasing for years further into the future. Such capacity markets are an administrative method of addressing a perceived market failure in which the contract length customers are willing to enter into for hedging purposes is too short to provide sufficient certainty for financing. In addition to providing greater long-term price transparency, the laddered capacity market would provide some elasticity to capacity pricing in future years.

Under a RAM regime, the IESO would set target internal reserve margins and administer

14 LSE territories would not map directly to the outline of all existing LDCs since some, such as Hydro One, own non-contiguous territories. Existing LDCs – or a group of LDCs – would be allowed to bid on LSE franchises through their unregulated subsidiaries, subject to current affiliate-relations codes designed to prevent the use of utility brands to create an unfair advantage in the retail market. Bidders for LSEs would have the right to supply and the obligation to serve existing regulated customers; this relationship may be valuable as a hedge for new generation businesses and for building new retail platforms. Within the confines of existing privacy laws, bidders would have information on customer numbers prior to the auction, on levels of demand and on load shapes. Proceeds from the auction would be used to reduce the GA.

15 The default offering for regulated customers would be divided between an energy and capacity component; the existing GA would continue to be assessed by LDCs on wire charges to assure that it remained non-bypassable.

Table 3: Indicative Forward Capacity Purchasing Requirements for LSEs

	Years from present time						
	+1	+2	+3	+4	+5	+6	+7
	(*Percent*)						
Capacity contracting requirement as percentage of current peak load in the specified future year	115	115	115	115	115	115	115
Share of requirement to be procured in present year	100	100	100	90	80	70	60
Effective capacity contracting requirement in present year	115	115	115	104	92	81	69

Source: Hypothetical example.

forward capacity markets. To provide a meaningful long-term investment signal,[16] LSEs would be required to demonstrate sufficient capacity to meet their current load plus required reserves for three years into the future, based on IESO projections. In addition, the LSEs would be required to contract for a declining proportion of current load plus reserves for each year, four to seven years into the future (see a representative example in Table 3). LSEs failing to meet their requirements would face a penalty equal to the monthly amortized cost of a new simple cycle gas turbine.

Capacity payments are substitutes for what would otherwise be higher peak prices. An effective capacity market may allow for reserve margin targets to be met with less need for super-peak pricing to signal that entry is necessary. New entrants may apply a lower capital cost to markets with multiple durable revenue streams, reducing long-run marginal costs. Furthermore, the cost of reliability itself becomes more explicit, allowing for more informed discussion of the trade-offs embodied in selecting a particular target reserve margin.

16 The seven-year laddered purchase requirement is intended to provide a long-term price signal that facilitates longer-term debt financing for developers, while not unduly burdening retailers. IESO will need to pay careful attention to the design of prudential requirements on LSEs and others trading in the RAM, so that credit requirements do not serve as undue barriers to entry in the retail market while protecting against the consequences of default.

Initially, and quarterly thereafter, the IESO would launch an auction for capacity for each of the years in the full seven-year forward period. Existing generators and new entrants would sell capacity not currently under OPA contract into the auction, and LSEs would purchase their requirements through the auction. LSEs would be allowed to procure capacity through bilateral contracts, but would need to register the contract with the IESO for compliance purposes. Other details, such as floor prices, would be subject to market design deliberations.[17]

Intermittent resources would be eligible for capacity based on resource-specific average seasonal capacity factors calculated by the IESO based on contribution to peak load. Generators with the most intermittent production should be disproportionately discounted in capacity markets, with the most reliable generating sources getting a higher capacity credit in capacity auctions.

Because of current ample supply in Ontario, it may be several years before a RAM would signal significant investment needs. However, the IESO should be attentive to synchronization of market rules with neighbouring markets to allow capacity export (or import). Because capacity cannot be sold in two markets simultaneously, subject to the amount of firm transmission available, capacity prices in neighbouring markets can help to provide an implicit floor for Ontario prices during years when the IESO-administered floor price related to low projected reserve margins is not in place.

Capacity Reallocation

OPA contracts represent the majority of provincial capacity. Dealing with existing contracts would require that they be transferred to the LSEs. However, a transfer of individual contracts could be administratively complex.[18] A more straightforward approach would be to allocate all of OPA's capacity to the LSEs, for a nominal dollar, on a pro rata basis using back-to-back contracts.[19] This means that over time, the contract capacity would taper off, after rising in early years for plants that have been contracted for but are not yet online.[20]

All LSEs registered by a cut-off date would be eligible for the capacity allocation based on their demonstrated existing peak load commitments. This vesting-style approach provides substance to newly formed LSEs by clarifying available supply.[21]

17 One of the biggest changes in capacity markets has been the increased ability of demand-response aggregators (entities that assemble commitments and capabilities to reduce load from smaller customers into blocks large enough to be dispatched) to participate. While demand response and physical generation are not equivalent, demand-response aggregators have proven to be highly flexible and have aided in maintaining reliability during tight supply situations. These aggregators would be eligible to participate in capacity auctions, subject to the same deliverability standards as conventional generation.

18 Rather than assigning existing OPA contracts, a better option would be for OPA to resell or assign the associated capacity to LSEs using new contracts. Existing OPA counterparties would see no change to their contractual relationship with OPA. Capacity allocation is a one-time exercise – once completed, it would not occur again, minimizing the possibility of investor uncertainty.

19 Because customers have already paid for existing capacity through the GA, and will continue to do so, it is not necessary for OPA to charge the LSEs for the capacity. Because the LSEs would be contracting for their net needs through the RAM, RAM pricing would reflect the non-energy costs of incremental capacity.

20 The outlook of future contracted capacity includes contracts that have been approved and are in process of being built; the moratorium would apply only to new incremental contracts.

21 LSEs would be allowed to sell surplus allocated capacity in neighbouring markets. Presumably, bidders for LSEs would incorporate this potential benefit into their LSE valuations, meaning customers would ultimately benefit since LSE auction proceeds would revert to customers through a GA reduction.

Default Supply Options

In a properly functioning energy market, each LSE would be required to offer its customers a default alternative of spot price plus RAM pass-through, similar to current prices. Customers on time-of-use (TOU) pricing would remain on the OEB price schedule if they lacked real-time meters (see Box 2). But they would be free to switch based on LSE competitive offerings, which would likely include long-term fixed prices for energy and RAM capacity.[22] To assure appropriate customer attribution of capacity transferred from the OPA, LSEs would be required to allocate this capacity monthly on a pro rata basis between default and contracted capacity.[23]

Why this Approach Is the Best Alternative for Ontario

Continuation of centralized contracting runs the risk that the government will use the power sector to meet the needs of narrow sets of constituencies at the expense of ratepayers as a whole. Even if current procurement arrangements can be sufficiently depoliticized, central planners may not be able to resist the temptation to stray from technologically neutral approaches.

By contrast, immediate transition to an energy-only market is also unfeasible. Investors would doubt that the government will allow prices to rise to levels that would make investment attractive.

The proposed RAM incorporates the best features of neighbouring markets, facilitating potential integration. At the same time, it creates a role for market-driven demand response. Customers would not pay twice for existing capacity: capacity under existing contracts will have already been allocated to LSEs, effectively making the RAM a residual capacity market. If accompanied by economy-wide efforts to price negative externalities from emissions and effluents, the arrangements would ultimately facilitate market-driven private-sector investments in the Ontario power sector consistent with the province's environmental goals.

PART 3: RELATED ISSUES

The evolution of wholesale electricity markets does not occur in a vacuum. This is particularly true in Ontario, where the current fuel mix is a legacy of prior government policies, resulting in a cascade of potential nuclear retirements through the coming decade. Choices for electricity market policy are shaped by, and in turn impact, pre-existing contracts and commitments along with climate change policies. Below, I discuss a range of issues that need to be considered in parallel with stabilizing the Ontario electricity market, along with potential complementary policies.

Evolution of OPG

For the RAM to work properly, it needs to

22 In order to offer fixed prices on RAM capacity, LSEs would need to be active participants in the RAM. Because of the requirement to contract for RAM seven years forward, LSEs would likely offer consumers forward terms of up to seven years; restrictions on switching after contracting but before the end of the contract term would be based on the LSE's commercial terms and conditions.

23 The RAM price pass-through for default customers would be a weighted average of the near-zero cost of the OPA-related component and the market-procured RAM capacity. Access to the OPA-related capacity volumes for contracted quantities would allow LSEs to craft competitive offerings while preventing creation of perverse incentives for default customers to avoid switching.

Box 2: Current Retail Supply Arrangements in Ontario

Currently, residential and small business consumers who buy their electricity directly from their local utility (instead of from retailers) pay either a tiered or time-of-use (TOU) rate according to the Regulated Price Plan (RPP), depending on whether they have smart meters.

RPP prices are set by the OEB and reviewed twice per year. To calculate RPP prices, the OEB forecasts the cost to supply electricity to RPP consumers for the next 12 months, taking into account factors such as forecast prices for coal and natural gas, supply-fuel mix, contracts with generators and demand forecast.

While all Ontario electricity consumers are required to pay their share of the GA, a forecast of the GA is also included in the RPP prices and, therefore, is not shown separately on the bill.

Effective May 1, 2013, the peak TOU price increased from 11.8 cents/kWh to 12.4 cents/kWh, and the off-peak price increased by 0.4 cents to 6.7 cent/kWh. For tiered prices, the first tier (up to 600 kWh per month for households) price will be 7.8 cents/kWh (0.4-cent increase from previous RPP). Above the tier threshold, the price will increase from 8.7 to 9.1 cents/kWh.

As of April 5, 2013, more than 80 percent of RPP-eligible consumers were on TOU billing.

Source: Ontario Energy Board (2013b).

incorporate OPG assets, and future OPG investments need to be driven by market forces.[24] While privatization of some or all of OPG would be beneficial to place it beyond the reach of ministerial directives, there are steps the government should consider other than privatization to improve the functioning of the Ontario wholesale power market.

OPA should develop contracts with OPG on a plant-by-plant basis for OPG prescribed assets, excluding contracts for new nuclear or nuclear refurbishment.[25] This would allow policymakers and company management greater flexibility in asset configuration should the government one day privatize OPG. These contracts would need to be sufficiently long to maintain OPG credit quality, but thereafter, provided OPG or its successor companies lacked market power, no further contracts other than those obtained commercially would be required.[26] OPG's non-prescribed assets would remain merchant, able to sell into both the energy market and the RAM, or enter into bilateral contracts.

Once the contracts commence, OPG would

24 OPG-prescribed assets include all nuclear facilities (Darlington and Pickering A and B) and most of its baseload hydroelectric facilities (Sir Adam Beck 1 and 2, DeCew Falls 1 and 2, and R.H. Saunders). For electricity generated by its prescribed facilities, OPG receives a regulated price determined by the OEB (OPG 2011).

25 For hydro plants on a single river system, a bundled contract could be considered.

26 Recent announcements that OPG will be allowed to bid for large-scale renewables contracts raise several potential concerns, however. While the shutdown of coal capacity has reduced OPG's overall market share, it remains dominant. Private-sector players competing against OPG will question whether OPG applies a commercially reasonable cost of capital to its projects and whether OPG has unfair access to sites, particularly those with favourable grid access. OPG has little experience with non-hydro renewable technologies, and investors may also question OPA's ability to negotiate as aggressively with OPG as it does with private entities if key contract milestones are missed.

no longer need to be rate regulated by OEB, lessening the regulatory burden significantly for all stakeholders. Moving OPG assets from regulation to contracts puts all market participants on a more level playing field. Furthermore, it allows the capacity from OPG prescribed assets to be allocated among LSEs as part of the process described above.[27] Finally, if it proves politically challenging to sell OPG plants outright, dispatch rights associated with the contracts can be auctioned to other market participants, addressing market power concerns and deepening the electricity market.[28]

Optimization of Existing Contracts

Honouring existing contracts is an essential component of creating a favourable investment climate. However, the OPA should examine whether existing contractual provisions make sense in a reformed market. That means the OPA should seek negotiated, mutually beneficial contract amendments with existing contract holders. The recent Samsung renegotiation provides a sensible template for modifying existing contracts. Uncompelled contract renegotiations are a normal feature of every-day commercial relationships. There are many possible contractual re-arrangements possible, such as a lump-sum payment in return for contract terminations or lengthening contract terms in exchange for a decrease in prices.

OPA could issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments associated with the plant. OPA should be able to utilize securitization techniques to arbitrage differences in cost of capital between it and its counterparties. Counterparties would receive a lump-sum payment to exit their contracts; their facilities would then become merchant plants, increasing the relevance of wholesale spot markets and releasing capacity to be contracted with third parties. OPA would issue long-term debt to make the lump sum payments, with the debt backed by future GA payments. Provided that payments on the debt are lower than the payments that OPA would otherwise have made on the terminated contracts, the GA would fall.

Cost-effectively Fulfilling Environmental Objectives

Power from fossil-fuels, even natural gas, produces climate change-causing carbon dioxide (CO_2) emissions. One of the lowest-cost ways to reduce CO_2 emissions is a cap-and-trade mechanism. A practical way for Ontario to implement cap-and-trade would be to join the cross-border Western Climate Initiative (WCI,[29] a system whereby designated polluters must obtain CO_2 credits from

27 While this capacity could theoretically still be allocated while remaining under regulation, mechanisms would need to be devised to ensure that all upgrades of regulated assets are financed on a market basis. Moving regulated assets to a contract basis would create greater investor confidence that OPG is not being subsidized by ratepayers.

28 A public entity like the Alberta Balancing Pool need not be created for this exercise; numerous examples of private-sector contracts transferring dispatch rights, such as tolling agreements, exist without the need for an intermediary. The Balancing Pool arose partially to serve as the counterparty for unsold dispatch rights, a problem that can be avoided through appropriate auction design.

29 The December 2009 Climate Change Action Plan set targets for reducing Ontario's greenhouse gas emissions ("GHG emissions"): 6% below 1990s levels by 2014, 15% by 2020 and 80% by 2050 and foresees working with WCI to design a cap-and-trade program. WCI is a collaboration of four Canadian jurisdictions (British Columbia, Manitoba, Quebec and Ontario) and California to develop infrastructure and administrative tools to support a regional GHG trading framework (Ontario Ministry of the Environment 2009, N.D.).

an emissions trading market. Under a WCI cap-and-trade scheme, Ontario could set the maximum amount of emissions credits it would allow in the market, reducing the amount over time in order to reduce emissions, and auction credits to the highest bidder. Because Ontario would be joining Quebec and California in an expanding continental emissions credit market, Ontario participants would have the benefits of a liquid market. The province would gain additional revenues from the sale of emissions credits consistent with the provincially set cap on CO_2 emissions.

Coupled with a phase-out of the FIT and renewables-specific procurements, joining WCI could ultimately be a more efficient way for Ontario to achieve environmental objectives than subsidizing wind power through a FIT program. If the price of delivered natural gas rose to $10 per MMBtu, a carbon dioxide emissions reduction credit price of $18 per ton would be needed for a wind generator to achieve the same revenues as it would under the FIT (Figure 7). Even if emission credit prices were to exceed $110 per ton of CO_2 and natural gas remains at the current price of about $4 per MMBtu, natural gas power plants would still be a lower-cost electricity source than the current wind FIT program.

Ontario could also reduce the cost impacts on its electricity consumers if it were to adopt a so-called "cap-and-dividend" approach, with the proceeds of emissions credit auctions applied toward reducing the GA.[30] Furthermore, Ontario could design floor and ceiling mechanisms, including "safety valves" involving greater use of emissions offsets, to manage emissions credit-price volatility.[31]

Part 4: Next Steps for the Province

"Press Pause"

To assure a sound foundation for future power sector policies, the provincial government should put all new contracting initiatives on hold and announce a moratorium on decisions affecting the wholesale generation market until a comprehensive and transparent policy review can be performed by a special review panel. Such a review should be time limited and include a consultative process. Terms of reference should focus on how to create a durable structure for the Ontario power sector to provide reliable electricity supply at long-run, least cost. This review would provide an opportunity for the province and stakeholders to consider the optimal structure for the energy industry.

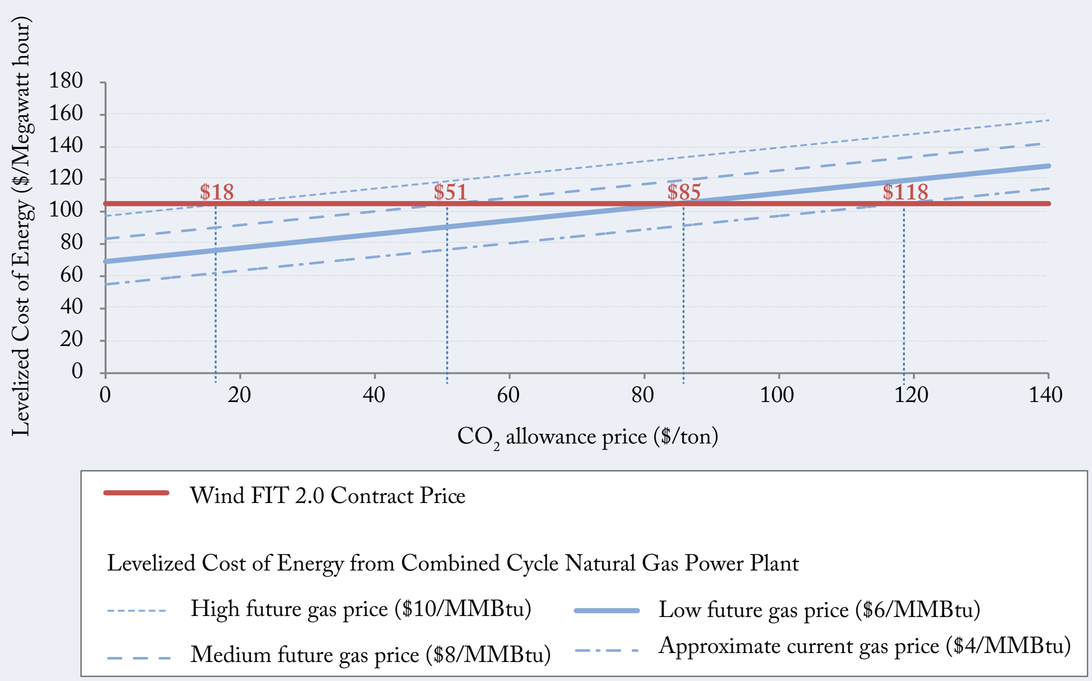
To inform the review, the OPA and IESO should perform a high-level, 10-year forward analysis of potential generation needs under various demand scenarios. Such an analysis should be technology and ownership neutral, but should highlight when and where on the supply curve (baseload, mid-merit or peaking) those needs are likely to arise.[32]

30 Change-of-law provisions in some OPA contracts may mean that some producers would pass through costs of emissions credits to consumers through the GA; a cap-and-dividend approach would offset the impact on consumers. A drawback of the cap-and-dividend method, however, is that it mutes the pricing of negative externalities for consumers.

31 In January 2013, the Ontario Ministry of the Environment published a discussion paper on ways to reduce greenhouse gas emissions, including applicability of a cap-and-trade scheme (Ontario Ministry of the Environment 2013, and Melnitzer 2013).

32 The consultation papers issued as part of the 2013 LTEP consultation process represent a good starting point for this analysis.

Figure 7: Implied Carbon Price Embedded within Wind FIT at Varying Natural Gas Prices



Note: Wind LCOE based on 30% capacity factor, 24-month construction period and $2,014/kW capital cost; gas prices range from a low of slightly above January 2013 levels to a level that is less than that which prevailed in 2008 prior to the world financial crisis.

Source: LEI calculations from OPA (2012g).

Indicative Timeline

If the government chooses to adopt a capacity market, reforms of market institutions could be gradually phased in before significant future capacity needs arise. An indicative timeline is outlined in Figure 8. Creating a capacity market will involve a number of steps, but is feasible within the lifetime of a single session of provincial parliament (see Box 3).

In the past, Ontario has made too many power sector changes simultaneously or issued policy changes too rapidly. Ideally, during the three-year capacity market implementation period, no other major changes in the power sector would be contemplated, at least on the generation side.

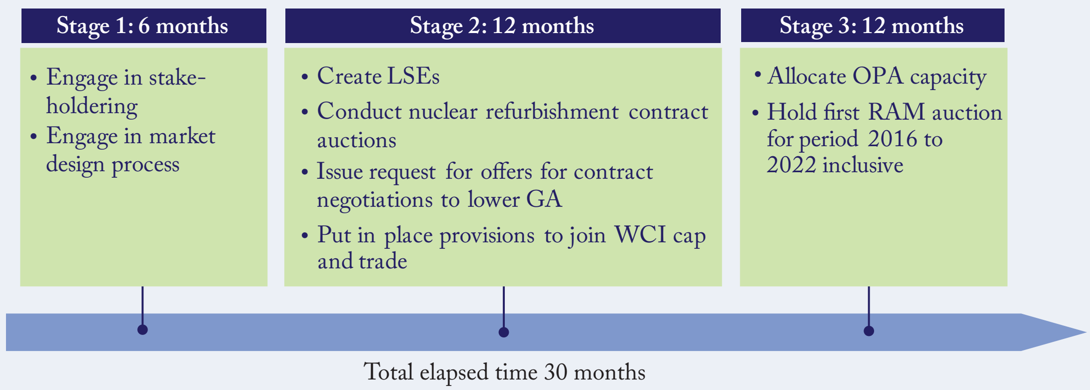
Assuring Political Viability

To avoid further cost increases and the risk of continued supply-demand mismatches, Ontario needs to have a comprehensive conversation about how to create a durable power market. Power market design evolutions are best implemented during a period of supply surplus, meaning that Ontario has a unique opportunity over the next few years to examine and implement changes that would put the power sector on a sound foundation

Box 3: The To-Do List for Ontario

1. Implement changes at relevant power market institutions to assure board members are independent, serve staggered defined terms and are subject to removal only for a limited number of reasons.
2. These institutions need dedicated funding streams protected from legislative whims.
3. Work to reduce, and even eliminate, the GA.
4. Re-orient the Ontario power sector away from the use of OPA as a principal buyer.
5. Enshrine the independence of key market institutions and clarify their mandates.
6. Maintain OPA and IESO as separate bodies.
7. Direct OPA to cease further contracting (including with expiring non-utility generators), focus on uncoerced mutually beneficial contract negotiations to reduce the GA and, ultimately, become a pure contracts administrator.
8. IESO should design demand-response programs consistent with its market operations.
9. The OEB should cease rate-regulating OPG prescribed assets, but periodically review OPA's budget, its progress in reducing the GA and plans for shrinking. OPA should develop contracts on a plant-by-plant basis for OPG-prescribed assets.
10. Explore the future role of nuclear. The OPA should hold a final procurement round, based on an announced maximum price consistent with a carbon-neutral CCGT and an assessment of the timing for baseload resource needs.
11. OPA should establish four or five new LSEs for sale by auction to the private sector, with their boundaries contiguous to LDC service territories. LDCs themselves would retain their current form and functions.
12. Form a new RAM and establish a laddered capacity market with purchase requirements decreasing with time.
13. Allocate all of OPA's capacity to the LSEs on a pro-rata basis, using back-to-back contracts. LSEs should then offer customers a default alternative of spot price plus RAM pass-through.
14. OPA should issue periodic calls for proposals from existing contract holders to modify their contracts, with the proviso that all proposals must result in a material reduction in GA payments.
15. Join an emerging Western Climate Initiative carbon dioxide emissions reduction credit market as a means to transition to cap-and-trade mechanisms.
16. Encourage demand-response aggregators and allow them to participate in capacity auctions.

Figure 8: Indicative Timeline for Consultative Process



Source: LEI.

for future investment. Doing so would benefit customers by returning the focus of power sector planning to long-run, least-cost principles, reducing the ability of policymakers to implement politically expedient measures that turn out to have hidden future costs.

In considering the proposed changes, the focus should be on decreasing long-term electricity costs while strengthening the Ontario economy. Consumers will welcome adjustments if they are convinced that costs will ultimately be contained. Rural Ontario would likely support the plan, provided it is clear that it does not entail any loss of local control. LDCs would not be forced to consolidate or become LSEs. Renewable energy projects would be market-based and not subsidized.

Three sources of opposition are possible: labour, environmental activists and privileged corporations.[33] However, each can likely be assuaged if the program is properly communicated and measures are taken to address specific concerns. While these proposed changes do not rely on privatization, unions should be encouraged to participate as owners should the government envision a sale of parts or all of OPG. Furthermore, given current demographics, protections for the existing workforce can be built into any sales agreements.

The changes I propose in no way undermine environmental protection and can be bundled easily with a meaningful climate change action plan. Indeed, implementing a cap-and-trade program as part of the WCI would demonstrate continued long-term commitment to the environment, as would focusing on economic demand-response programs.

33 Policymakers should not underestimate the possible extent of rent-seeking embedded in current Ontario arrangements, whether on the part of unions at provincially owned enterprises or clean-energy advocates in designing the Feed-in Tariff. The proposed framework would improve transparency and diminish the ability of parties to increase rents by bypassing the market in favour of government-sanctioned support from taxpayers or ratepayers.

Although corporate interests will no doubt complain about the lack of long-term contracts, many businesses recognize that the Ontario power sector as currently constructed is unsustainable. A credible plan for reducing electricity costs using market forces will ultimately win favor from investors.

The plans need not involve acknowledging any previous mistakes. A "mission accomplished" approach would focus on the fact that coal has been successfully eliminated, that the government has procured a significant amount of zero-emitting capacity and has created a supply surplus that enables the long-term reforms I propose.

Ontario's electricity institutions have matured to the point where their independence would be beneficial. Careful attention to messaging and repeated focus on how the plan reduces costs without harming labour or the environment will contribute to its success.

In short, common-sense solutions exist that will allow for a reduction in long-term Ontario power costs that will contribute to economic development. These solutions do not require the creation of new institutions, nor do they require abandoning key policy objectives such as environmental protection.

Appendix

Table A: Back Up to Levelized Cost of Energy Calculations

[2012 dollars]	CCGT	CCGT (high)	Biomass (Atikokan)	Onshore Wind (high)	Nuclear (Bruce A units 1 & 2) (high)	Nuclear Refurbishment (low)	New Nuclear (low)
Capital cost [$/kW]	1,016	1,230	8,500	2,535	3,200	3,338	5,339
Leverage	60%	60%	60%	60%	60%	60%	60%
Debt interest rate	8%	8%	8%	8%	8%	8%	8%
Tax rate	40%	40%	40%	40%	40%	40%	40%
After-tax required equity return	15%	15%	15%	15%	15%	15%	15%
Debt financing term	18	18	18	18	18	18	18
Equity contribution capital recovery term	20	20	20	20	20	20	20
Construction time (months)	36	36	48	24	72	60	72
Heat rate [Btu/kWh]	7,050	7,050	13,500		10,460	10,460	10,460
Nominal variable O&M [$/MWh]	3.6	3.6	5.2		2.1	2.1	2.1
CO_2 content [lb/MMBtu]	120	120					
Carbon cost [$/ton]		20.0					
CO_2 adder [$/MWh]		8.5					
Nominal fixed O&M [$/kW/year]	15.0	15.0	104.6	29.2	92.3	92.3	92.3
Capacity factor	85%	70%	85%	30%	90%	90%	90%
Fuel price [$/MMBtu]	$6.9	$7.5			$0.4	$0.4	$0.4
All-in fixed cost [$/kW-yr]	$144	$171	$1,215	$340	$536	$542	$833
Levelized non-fuel cost of new entry [$/MWh]	$23	$40	$168	$129	$70	$71	$108
Levelized Cost of Energy (“LCOE”) of new entry[$/MWh]	**$71**	**$93**	**$168**	**$129**	**$75**	**$75**	**$112**

Table A: Continued

[2012 dollars]	CCGT	CCGT (high)	Biomass (Atikokan)	Onshore Wind (high)	Nuclear (Bruce A units 1 & 2) (high)	Nuclear Refurbishment (low)	New Nuclear (low)
Carrying charge until commissioning [$/kW]	$146	$177	$1,632	$243	$922	$801	$1,538
Amortized carrying charge over debt term [$/kW/year]	$12	$15	$137	$20	$78	$67	$129
Debt-financed portion [$/kW]	$610	$738	$5,100	$1,521	$1,920	$2,003	$3,203
Annual debt repayment [$/kW/year]	$51	$62	$429	$128	$162	$169	$270
Equity-financed portion [$/kW]	$407	$492	$3,400	$1,014	$1,280	$1,335	$2,136
Annual equity return [$/kW/year]	$65	$79	$543	$162	$204	$213	$341
CCGT LCOE (low) [$/MWh] ($20/ton carbon cost)	$80	Wind FIT 2.0 Contract Price (low) [$/MWh]		$105			
CCGT LCOE [$/MWh] ($40/ton carbon cost)	$91	Nuclear Bruce A units 1 & 2 OPA Contract Price (low) [$/MWh]					
CCGT LCOE [$/MWh] ($60/ton carbon cost)	$99				$68		
CCGT LCOE [$/MWh] ($80/ton carbon cost)	$108	Nuclear Refurbishment LCOE (high) [$/MWh] ($4,285/kW capital cost)					
CCGT LCOE [$/MWh] ($100/ton carbon cost)	$116					$92	
CCGT LCOE [$/MWh] ($120/ton carbon cost)	$125	New Nuclear LCOE (high) [$/MWh] ($6,797/kW capital cost)					
CCGT LCOE [$/MWh] ($140/ton carbon cost)	$133						$138

Notes: LCOE as of 2012. All figures nominal Canadian dollars and assuming exchange rate CA $1/US$. Sources: LEI calculations from Energy Velocity commercial database; EIA (2012); OPG (2011); OPA (2012a,g,h); Areva (N.D.); Energie NB Power (2008-2012a,b); Bissett (2012); Hydro Quebec (N.D.); *CNBC (2012)*; and *World Nuclear News*.

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