

**Integrated Resource Plan**

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**Appendix 7K**

**Technical Advisory Committee – Written  
Submissions on Consultation Topics 2013**

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## 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](http://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<sup>1</sup>. 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<sup>2</sup>.

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.

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<sup>1</sup> The Act received royal assent on June 3, 2010.

<sup>2</sup> 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<sup>3</sup>.
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.

<sup>3</sup> 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)<sup>4</sup>**

|  | F2017         | F2021         | F2026         | F2031          |
|--|---------------|---------------|---------------|----------------|
| <b>Energy Surplus/Deficit Without LNG</b>                      |               |               |               |                |
| <b>2012 Draft IRP with Critical Water</b>                      | <b>-1,061</b> | <b>-3,754</b> | <b>-6,187</b> | <b>11,297</b>  |
| add: Change to Average Water Planning Criterion                | 4,100         | 4,100         | 4,100         | 4,100          |
| <i>2012 Draft IRP with Average Water</i>                       | <i>3,039</i>  | <i>346</i>    | <i>-2,087</i> | <i>-7,197</i>  |
| 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            |
| <b>2013 IRP Energy Surplus/Deficit</b>                         | <b>5,041</b>  | <b>2,180</b>  | <b>284</b>    | <b>-3,307</b>  |
| <b>Energy Surplus/Deficit With LNG</b>                         |               |               |               |                |
| <b>2012 Draft IRP with Critical Water</b>                      | <b>-4,861</b> | <b>-9,035</b> | <b>-</b>      | <b>-</b>       |
| add: Change to Average Water Planning Criterion                | 4,100         | 4,100         | 4,100         | 4,100          |
| <i>2012 Draft IRP with Average Water</i>                       | <i>-761</i>   | <i>-4,935</i> | <i>-7,367</i> | <i>-12,478</i> |
| 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            |
| <b>2013 IRP Energy Surplus/Deficit</b>                         | <b>5,041</b>  | <b>180</b>    | <b>-2,715</b> | <b>-6,307</b>  |

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)<sup>5</sup>.
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.

<sup>4</sup> Source: information provided by BC Hydro to TAC members by email dated October 9, 2013.

<sup>5</sup> 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<sup>6</sup>.

### 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<sup>7</sup>.

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<sup>6</sup> Summarized from figures 8-3 and 8-4 on pages 8-46 and 8-47 of the August 2013 IRP.

<sup>7</sup> 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<sup>8</sup>.

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<sup>9</sup>.

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.**

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<sup>8</sup> Summarized from pages 8-20 to 8-21 of the August 2013 IRP.

<sup>9</sup> 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<sup>10</sup>.

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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<sup>10</sup> 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<sup>11</sup>.

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.

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<sup>11</sup> 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 ratepayers<sup>12</sup>. 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<sup>13</sup>. 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.

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<sup>12</sup> Summarized from pages 8-39 to 8-40 of the August 2013 IRP.

<sup>13</sup> 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)<sup>14</sup>. 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<sup>15</sup>.

### 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<sup>16</sup>.

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<sup>17</sup>.

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.**

<sup>14</sup> Page 2-2. August 2013 Integrated Resource Plan.

<sup>15</sup> Summarized from figures 8-5 and 8-6 on pages 8-61 and 8-62 of the August 2013 IRP.

<sup>16</sup> Summarized from pages 8-52 to 8-54 of the August 2013 IRP.

<sup>17</sup> 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<sup>18</sup>.

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<sup>19</sup>.

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<sup>20</sup>. 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 in 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

<sup>18</sup> Summarized from pages 8-54 to 8-55 of the August 2013 IRP.

<sup>19</sup> Final Report on BC Hydro's Energy Procurement Practices. Merrimack Energy Group. 2011.

<sup>20</sup> 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<sup>21</sup>. 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.

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<sup>21</sup> 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<sup>22</sup>.

**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<sup>23</sup>.

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

<sup>22</sup> Summarized from pages 8-74 and 8-75 of the August 2013 IRP.

<sup>23</sup> 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)<sup>24</sup>. 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.

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<sup>24</sup> 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**

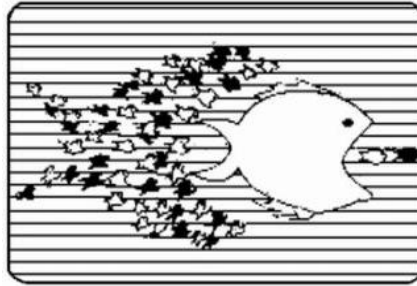
The FNEMC is also providing comments on First Nation policy and process considerations under separate cover. The review process contemplated by the province, and the decisions or actions that may flow from any approvals are not clear. The provincial government should provide timelines for review of the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

WRITTEN SUBMISSION FROM:  
BRITISH COLUMBIA PENSIONERS' AND SENIORS'  
ORGANIZATION

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**Via Email**

October 18, 2013

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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 is 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 requirements – 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<sup>1</sup>. 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<sup>2</sup>. 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 CO<sub>2</sub> emitted in BC contributes no more to climate change than a ton of CO<sub>2</sub> 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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<sup>1</sup> Rates Working Group: Session 1, August 23, 2013

<sup>2</sup> 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<sup>3</sup>. 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<sup>4</sup>.

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<sup>5</sup>. These figures represent good value. Furthermore, BC Hydro has historically underspent its DSM budget and over-achieved its DSM target<sup>6</sup>. 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

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<sup>3</sup> Industrial Electricity Policy Review Task Force Interim Report, October 4, 2013, p.5

<sup>4</sup> 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

<sup>5</sup> BC Hydro Draft 2013 Residential Inclining Block Rate Re-Pricing Application, p.1-17

<sup>6</sup> EN6 Demand Side Management 2011

[http://www.bchydro.com/about/accountability\\_reports/2011\\_gri/f2011\\_environmental/f2011\\_environmental\\_EN6\\_2.html](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<sup>7</sup>. 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

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<sup>7</sup> Rates Working Group: Session 1, August 23, 2013, p.























































































































































































































































































































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<sub>2</sub> 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<sub>2</sub> 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.<sup>30</sup> Furthermore, Ontario could design floor

and ceiling mechanisms, including “safety valves” involving greater use of emissions offsets, to manage emissions credit-price volatility.<sup>31</sup>

## 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.

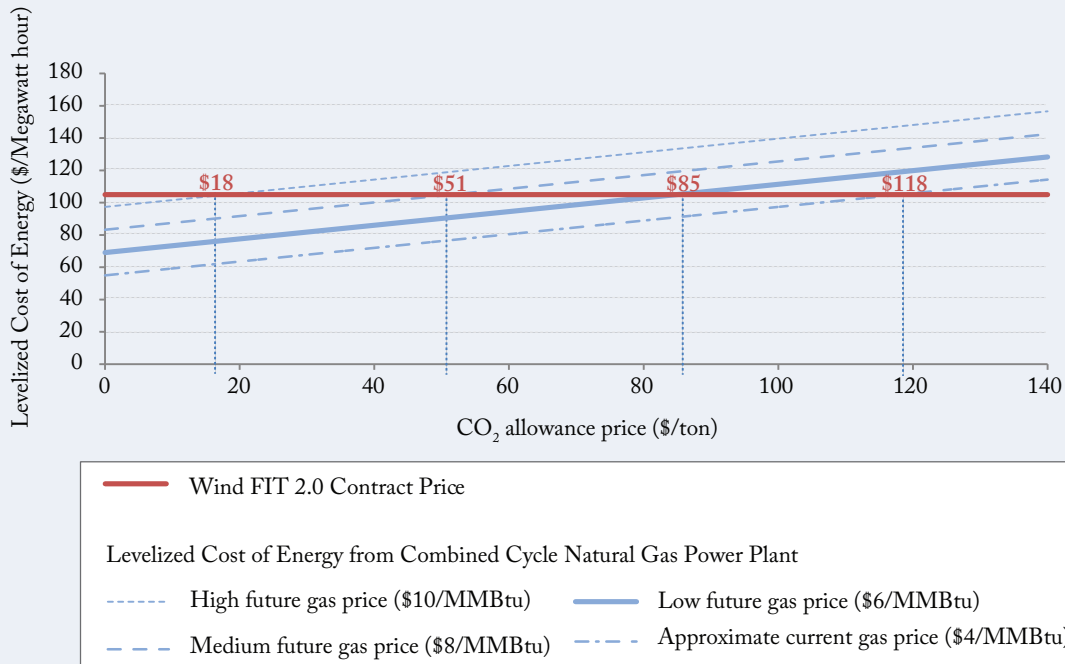
To inform the review, the OPA and IESO should perform a high-level, 10-year forward analysis of potential generation needs under various demand scenarios. Such an analysis should be technology and ownership neutral, but should highlight when and where on the supply curve (baseload, mid-merit or peaking) those needs are likely to arise.<sup>32</sup>

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.

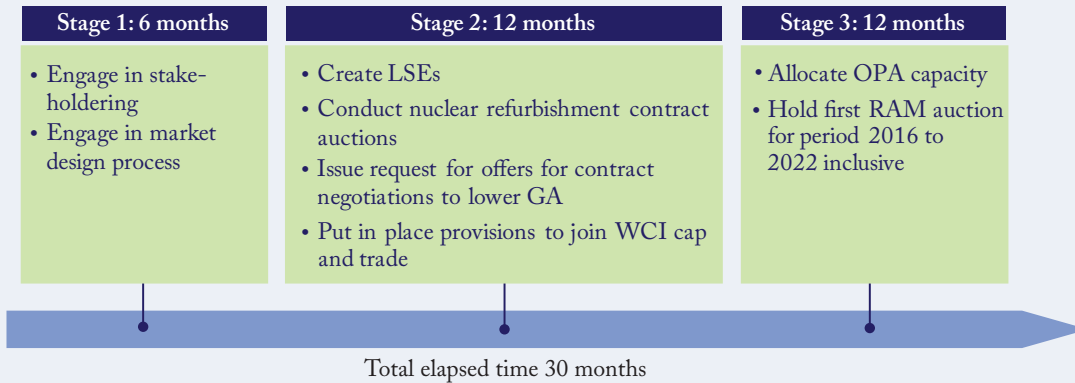
### Assuring Political Viability

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 ladder 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.<sup>33</sup> 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.

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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 <sub>2</sub> content [lb/MMBtu]                             | 120         | 120         |                    |                     |                                      |                             |                   |
| Carbon cost [\$/ton]   |             | 20.0        |                    |                     |                                      |                             |                   |
| CO <sub>2</sub> 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             |
| <b>Levelized Cost of Energy (“LCOE”) of new entry [\$/MWh]</b> | <b>\$71</b> | <b>\$93</b> | <b>\$168</b>       | <b>\$129</b>        | <b>\$75</b>                          | <b>\$75</b>                 | <b>\$112</b>      |











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