BCH 2005 REAP – Exhibit B-11

BC hydro

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July 8, 2005

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

RE: Project No. 3698388
British Columbia Hydro and Power Authority (BC Hydro)
2005 Resource Expenditure and Acquisition Plan

Enclosed is BC Hydro's Supplemental F2006 Call Evidence.

As part of their information requests (IRs) submitted on May 9, 2005, several intervenors included IRs respecting the F2006 Call. BC Hydro proposes to respond to those F2006 Call related IRs at the same time it responds to the next round of IRs.

Yours sincerely,

Tony Morris

Tony Morris
Acting Chief Regulatory Officer

c. Project No. 3698388 Intervenors

British Columbia Hydro and Power Authority
2005 Resource Expenditure and Acquisition Plan
British Columbia Utilities Commission
Project No. 3698388

DIRECT TESTIMONY OF MARY HEMMINGSEN

Q1. Please introduce yourself to the British Columbia Utilities Commission (Commission).

A. My name is Mary Hemmingsen. Since May 2003, I have been the Manager of Power Planning and Portfolio Management for BC Hydro.

From 1994 to 2003, I held various positions at BC Hydro including Manager of Corporate Development and Finance, Manager of Business Development, Manager of Corporate Finance Evaluation and Strategy, Manager of the Corporate Financial Office and Project Manager for Business Power Smart.

Q2. What are your professional qualifications?

A. I obtained a Bachelor of Business Administration (1986) and I am a Chartered Accountant (1989).

Q3. Have you previously testified before this Commission?

A. Yes. I testified at BC Hydro's 2003 Vancouver Island Generation Project Certificate of Public Convenience and Necessity Application hearing, its 2004 Revenue Requirements Application hearing and its 2005 Vancouver Island Call for Tenders (VICFT) hearing.

Q4. What are the subject matters of your evidence?

A. My evidence will address the following issues:

First, I will describe the nature of the electricity product to be acquired pursuant to the proposed "open call" to the private sector in fiscal 2006 (F2006 Call).

Second, I will confirm the need for the F2006 Call, including the reasons for the increased call size and the rationale for seeking firm energy.

Third, I will describe the reasons that BC Hydro has selected a Call for Tenders (CFT) process for the F2006 Call. I will also describe the assessment criteria and mandatory requirements for the F2006 Call.

Fourth, I will describe the proposed key terms and conditions of the F2006 Call Electricity Purchase Agreement (EPA), how risks are to be allocated pursuant to those terms and conditions, and address the considerations that informed the proposed risk allocation. I will also describe the extent to which the key terms and conditions on a global basis are generally consistent with commercial and legal terms and conditions in long-term supply arrangements used by other utilities and jurisdictions in procuring electrical energy or where they significantly differ, the basis for the terms proposed by BC Hydro.

Fifth, I will describe the risks associated with future greenhouse gas (GHG) compliance and how such GHG risks are allocated in the F2006 Call.

Sixth, I will outline the step-by-step process BC Hydro will employ to implement the F2006 Call.

Finally, I will outline the various steps BC Hydro has taken to obtain First Nations and stakeholder input on the F2006 Call and respond to their comments.

The exhibits attached to my testimony are:

Exhibit A: CFT Process – Mandatory Requirements;
Exhibit B: Tender Evaluation Criteria and Methodology – Key Elements;
Exhibit C: EPA Terms and Conditions;
Exhibit D: Alcan Inc. Recall Notice;
Exhibit E: Energy for Our Future: A Plan for BC;
Exhibit F: List of Acquisition Processes Selected; and
Exhibit G: List of Acronyms.

The Product

Q5. What are the products being sought in the F2006 Call?

A. BC Hydro is targeting to procure a minimum of 1,000 gigawatt hours per year (GWh/year) of electrical energy as follows:

(a) minimum of 800 GWh/year of firm electrical energy supply and up to 800 GWh/year of associated non-firm electrical energy supply from projects 10 megawatts (MW) and larger (Large Projects) built and operated by independent power producers (IPPs); and

(b) minimum of 200 GWh/year (based on a 50 MW portfolio at approximately 50% capacity factor) of electrical energy supply from projects 1 MW and larger, but less than 10 MW (Small Projects) built and operated by IPPs.

Primarily, the F2006 Call will focus on acquiring firm energy but will also allow for delivery of non-firm energy. Firm energy has been defined for the purposes of the F2006 Call to represent a volume of energy, with a contractually assured delivery, that an IPP must commit to providing over a specified period.

Energy is to be delivered under an EPA with a term ranging from 15 to 40 years (as selected by the bidder) from projects with a Commercial Operation Date (COD) targeted between October 1, 2008 and October 1, 2009.

In addition to the energy being acquired, BC Hydro may also acquire the "Green Attributes" associated with power projects. These attributes include green rights, green tags and other credits and allowances for greenness.

Q6. Please describe the treatment of Green Attributes in the F2006 Call.

A. Certain projects may have Green Attributes related to their low environmental impact. Successful bidders whose electricity conforms to the criteria established under Environment Canada's Environmental Choice^{M} Program (ECP) may apply to the ECP for verification and subsequent authorization to label the qualifying products with ECP's EcoLogo^{M}. The ECP maintains verification protocols that clearly define the terminology and associated criteria limits.

Regarding the Green Attributes, bidders will be given the option of (a) keeping the Green Attributes for sale or use in other markets; or (b) assigning the Green Attributes to BC Hydro and, for such assignment, receiving a credit in the tender evaluation of $3/MWh. Bidders that do not tender the Green Attributes of their projects to BC Hydro may still be considered BC Clean Electricity for evaluation purposes, provided their projects meet the BC Clean Electricity requirements, which are set out later in my testimony. Bidders that elect to assign the Green

Attributes to BC Hydro will retain the ability to apply for government programs such as the federal Renewable Power Production Incentive (RPPI) or Wind Power Production Incentive (WPPI). If the government program requires government ownership of the Green Attributes, BC Hydro will forfeit its rights to the Green Attributes and adjust the contracted power price downward by $3/MWh (escalating at Consumer Price Index (CPI) from January 2006) in order to recoup the evaluation credit previously provided to the successful bidder.

Q7. Why has BC Hydro chosen an evaluation credit of $3/MWh for the Green Attributes?

A. The $3/MWh credit is indicative of the value of the Green Attributes in the market. Green Attributes are currently trading in the range of $2 to $3 (US) per MWh (depending on the technology). Although trading is relatively illiquid at this time, this current market value established by counterparties transacting in an open market provides a relevant indicator of the value of Green Attributes.

Other indicators of value considered that offer high benchmark value include:

(a) pursuant to a recent Request for Proposal (RFP) by Excel Energy's Public Service Company of Colorado, renewable projects are eligible for a credit of $8.75 (US)/MWh for "green rights"; and

(b) Canada's federal government proposal for a $10/MWh power production incentive payment for renewable and wind power projects for a 10-year term.

BC Hydro believes that a $3/MWh credit for Green Attributes is reasonable given that it reflects a transparent market-driven value and is at the lower end of the range of values provided by relevant benchmarks.

The Need for the F2006 Call

Q8. Why has the F2006 Call size increased from the 400 GWh/year call previously approved by the Commission to 1,000 GWh/year as filed in the 2005 Resource Expenditure and Acquisition Plan (2005 REAP)?

A. In the Action Plan arising from the 2004 Integrated Electricity Plan (2004 IEP), BC Hydro indicated that it would issue a call to the private sector in F2005 to acquire up to 400 GWh/year for delivery starting in F2009. The Commission approved the 400 GWh/year call in its October 29, 2004 Revenue Requirements decision (the RRA Decision) based on the risks and uncertainties in the supply/demand balance that existed at that time.

As set out in Section 2 of the 2005 REAP and summarized at pages 2-46 to 2-47, the call size has changed from the previously approved 400 GWh/year level due to increased load growth and the need to hedge against various uncertainties. The requirement for increased energy supply stems from several changed circumstances, including:

(a) increase in the load forecast net of Demand Side Management (DSM);

(b) the loss of the Alcan Long Term Electricity Purchase Agreement (LTEPA) due to Alcan Inc.'s (Alcan) notice to recall the LTEPA starting January 2010. Alcan's recall notice is attached hereto and marked **Exhibit D**.

As noted in the 2005 REAP, additional supply and demand uncertainties include future load growth, IPP attrition and energy savings from DSM initiatives. The impact of these factors on the projected energy demand/supply balance reinforces the extent of risks and uncertainties BC Hydro needs to manage in ensuring adequate supply. At the time that the 2005 REAP was filed, BC Hydro believed that it was prudent to increase the size of the F2006 Call to the quantities identified in the 2005 REAP in order to mitigate its demand/supply imbalance risks. Since that time, BC Hydro proposes to increase the size of the F2006 Call from a target maximum of 1,000 GWh/year to a target minimum of 1,000 GWh/year.

Q9. Why has the size of the F2006 Call now changed from a target maximum of 1,000 GWh/year to a target minimum of 1,000 GWh/year?

A. Subsequent to the filing of the 2005 REAP and, as a result of the termination of the Duke Point Power (DPP) project, the size of the call for Large Projects has

been increased from up to 800 GWh/year to a minimum of 800 GWh/year of firm energy (plus 200 GWh/year of Small Project energy). The intent of the modification is to extend beyond the 800 GWh/year firm energy limit if cost-effective bids are received above this level.

The BC Hydro 2005 REAP demand/supply balance, from which the DPP project energy has been removed, forecasts a supply shortfall of 1,600 GWh in F2011. The 2005 REAP did assume 800 GWh/year of firm energy deliveries in F2011 from the F2006 Call. The demand/supply balance will be revisited prior to the tender evaluation and will be used as a criterion in selecting the optimal portfolio.

In addition, as set out in the 2005 REAP, BC Hydro currently contemplates the issuance of a F2007 call, which will be informed by the long-term acquisition plan arising out of the 2005 IEP to be filed with the Commission for regulatory review in conjunction with and as part of BC Hydro's 2006 REAP.

Q10. In examining the need for the F2006 Call, has BC Hydro compared a call to the private sector with other alternatives?

A. Yes, indirectly and in separate, parallel processes. The F2006 Call does not include the following resource types that are currently provided for through other BC Hydro initiatives:

- BC Hydro plant efficiency improvements (Resource Smart),
- Conservation and energy efficiency (Power Smart),
- Load Displacement-style customer-owned generation, and
- Down-Stream Benefits.

Including these options in the Call would increase the complexity of the Call substantially, while negatively impacting the process transparency and cost, as each option has unique features and considerations relating to size, scheduling, implementation, risk and measurement.

The need for the F2006 Call stems from the work done for the 2004 IEP and REAP to identify and assess a cost-effective portfolio of resources to meet BC Hydro's electricity demand. This assessment supported the need to continue BC Hydro's Resource Smart, Load Displacement and Power Smart activities. The F2006 Call is being undertaken to satisfy the balance of resource needs beyond those that can be satisfied by these alternate resource programs.

The alternative resource types mentioned here are developed and acquired by BC Hydro when and as appropriate through separate processes. These processes result in consistent, cost-effective decisions across the breadth of

supply alternatives available to BC Hydro as was contemplated in Policy Action #9 of the document entitled "Energy Plan for Our Future: A Plan for BC" (the BC Energy Plan), attached hereto and marked **Exhibit E**.

Q11. Is the need for, or quantity of, the F2006 Call caused by BC Hydro's proposal in the 2005 REAP to assume for planning purposes that Burrard Generating Station (Burrard) will not be relied upon for dependable capacity or firm energy beyond F2014?

A. No. In the RRA Decision, the Commission accepted uncertainty respecting the future of Burrard as part of the justification for the approved 400 GWh/year call. While there continues to be uncertainty respecting the potential phase out of Burrard prior to F2014, the specific assumption for planning purposes that Burrard cannot be relied on for dependable capacity or firm energy beyond F2014 is not the cause of the increased call size.

Q12. Why has BC Hydro decided to acquire firm energy and associated non-firm energy from Large Projects?

A. Firm energy supply has always been important to BC Hydro given its obligation to provide reliable electricity service to its customers. In its recent calls, BC Hydro has reflected the need for firm energy through various adjustments in the evaluation process and through prescribed EPA obligations. The requirement to deliver a specified minimum volume of energy (in the form of "firm" energy) over a specified period of time, together with contractual remedies for delivery shortfalls, enhances reliability and predictability of power supply to BC Hydro.

With the increasing reliance on IPP supply, BC Hydro needs to ensure that the supply contracted under EPAs carries firm delivery commitments and that new supply does not detract from the value of the existing system. For the F2006 Call, BC Hydro is proposing to acquire monthly firm or hourly firm energy as tendered by bidders. Monthly firm energy provides a balance between the capability of various IPP resources and BC Hydro's system limitations. The hourly firm option is intended to incent bidders to provide a higher-value "capacity rich" product, if available, by providing a $3/MWh evaluation credit adjuster for such projects.

The basis for the additional value provided by a project that provides firm energy on an hourly resolution is the levelized cost of Revelstoke Unit #5, inclusive of forgone system benefits to BC Hydro, a proxy for BC Hydro's cost of incremental intra-day system capacity.

While BC Hydro is seeking to acquire firm energy, it recognizes that some projects will have associated non-firm energy. Accordingly, BC Hydro is prepared

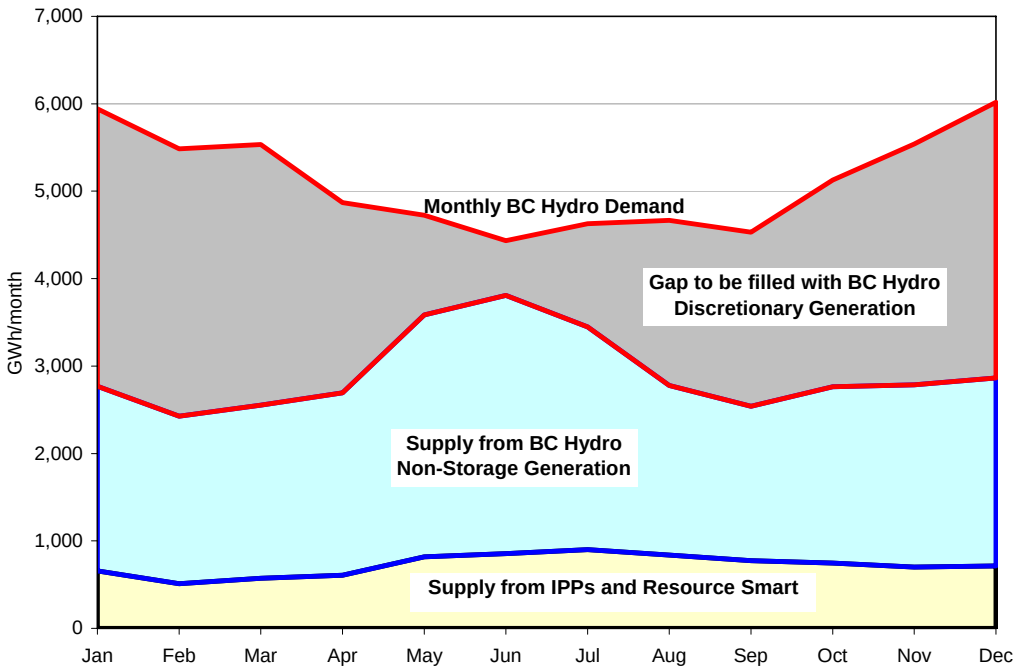
to accept and pay for that non-firm energy at a discounted price in order to ensure that such projects can compete in the F2006 Call and that such non-firm energy is acquired in a cost-effective manner for the benefit of ratepayers.

Q13. Why does BC Hydro place a constraint on the seasonal distribution of tendered firm energy?

A. As can be seen in Figure 1, BC Hydro's energy needs vary throughout the year. The chart represents the gap between BC Hydro's demand and the supply of energy from non-discretionary sources. The gap between demand and non-discretionary supply is met by discretionary generation such as dispatchable resources and imports.

Based on the seasonal energy requirement, BC Hydro is proposing in the F2006 Call to limit the relative amount of non-discretionary firm energy that it purchases in the months of April through July to 1/3 of the total annual volume of firm energy tendered. If BC Hydro does not start to limit the amount of such energy relative to the amount that is delivered in the other months, its system will become increasingly constrained. It is also recognized that for those IPPs that have some degree of control over their delivery profile, the Call process will allow them to optimize their bid prices and energy profiles. It is also recognized that some IPPs have limited control over their delivery profiles but require some degree of pricing certainty to make their projects economically viable. BC Hydro will accept and pay for all energy delivered up to 120% of plant capacity for non-split bids. By doing so BC Hydro is trying to strike a balance between those IPPs which have limited control over their delivery profiles and BC Hydro's system needs. This will benefit BC Hydro's ratepayers by increasing the pool of competitive bidders, which should result in lower bid prices.

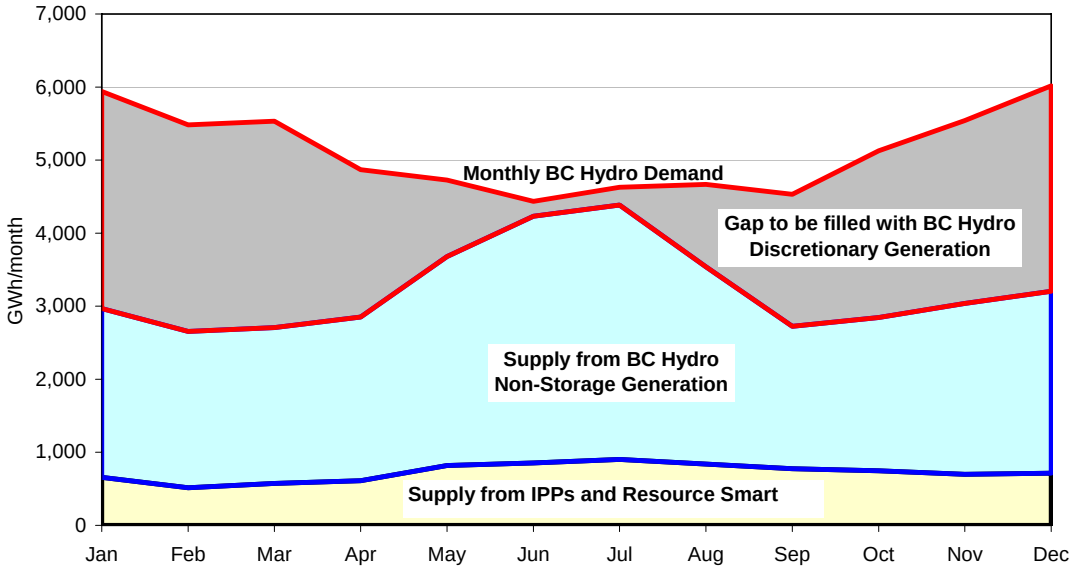
Figure 1: Average BC Hydro Supply and Demand - Seasonal Profile



Notes:
1. Load figures include BC Hydro and Fortis and are forecasted for year 2008.
2. IPP figures include Resource Smart (415 GWh) & are forecasted for year 2008.
3. Hydro generation figures include BC Hydro and Fortis resources minus the storable/dispatchable amounts from GMS, PCN, REV, & MCA. Figures are developed from historical records for the period 1985 to 2004. Average year is mathematical average of historical records.

Any additional energy received by BC Hydro in the summer months (especially in wetter years as shown in Figure 2) could force sales into an energy market that may have depressed prices, or result in hydraulic energy lost through spill past unloaded turbines. To address the time-specific value of delivered energy, which is affected by seasonal and intra-day market supply/demand, BC Hydro is proposing to incent suppliers who are able to provide a larger proportion of their annual energy delivery in the high demand months and a lower proportion during the low demand months. BC Hydro proposes to do this through the application of a price premium/discount table; Table 1 has been included as a sample. The factors in the final table to be issued as part of the EPA will be applied to the tendered price of successful bidders. This approach to valuing energy has been used in previous BC Hydro calls. The final table, which will be issued to bidders prior to tender submission, will be derived from BC Hydro's most current long-term market price forecast.

Figure 2: Wet Year BC Hydro Supply and Demand - Seasonal Profile



Notes:
1. Load figures include BC Hydro and Fortis and are forecasted for year 2008.
2. IPP figures include Resource Smart (415 GWh) & are forecasted for year 2008.
3. Hydro generation figures include BC Hydro and Fortis resources minus the storable/dispatchable amounts from GMS, PCN, REV, & MCA. Figures are developed from historical records for the period 1985 to 2004. Year 1999 selected as wettest on record.

Table 1
Sample Price Premium/Discount (HLH/LLH) Table

	HLH	LLH
January	113%	97%
February	109%	102%
March	105%	100%
April	103%	88%
May	104%	73%
June	104%	71%
July	104%	77%
August	104%	97%
September	105%	98%
October	103%	89%
November	106%	104%
December	117%	101%

Proposed Call and Mandatory Requirements

Q14. What is the purpose of this section of your evidence?

A. In this section, I will describe the objectives of the CFT process and why a CFT process was chosen. Additionally, I will review the mandatory requirements of the F2006 Call.

BC Hydro recognizes that it is incumbent on the utility to demonstrate that any new resource options are "cost-effective". Cost-effectiveness does not refer only to least cost but also encompasses factors such as reliability, security of supply, price risk, project timing and the financial capability and experience of the bidder. In this Call cost-effectiveness is demonstrated through a competitive market-based process in which the mandatory criteria are not unduly restrictive in a way that unreasonably eliminates or discourages options capable of meeting requirements from competing.

Q15. What are the overall F2006 Call process objectives?

A. The F2006 Call has been guided by BC Hydro's commitment to:

- secure a cost-effective, reliable supply of electrical energy that meets BC Hydro's requirements from financially and technically qualified IPPs,
- facilitate an environment which fosters competitive, realistic and disciplined pricing,
- implement measures in the process and EPA terms and conditions to:
  - increase BC Hydro's confidence that projects for which EPAs are awarded will achieve commercial operation as scheduled and will operate as required under the EPA, and
  - place the associated supply and contracting risks on the party most able to effectively price, manage and mitigate such risks,
- avoid unnecessary complexity and provide fairness to bidders in process execution and tender evaluation, and
- reduce transaction and ongoing administration costs.

Q16. What process will be used for the F2006 Call?

A. The F2006 Call is proposed to be a call for tenders process. A CFT process requires that Bidders submit legally binding, irrevocable, priced tenders to enter into a stipulated form of EPA.

BC Hydro has elected to proceed with a CFT process rather than a request for expressions of interest or proposals or a sole-sourced negotiation process because a CFT process:

- assures BC Hydro of serious, legally binding and achievable offers,
- provides bidders with greater certainty that BC Hydro will proceed to award,
- allows all bidders in each “stream” to compete based on the same contract terms and risk profile which, in turn, allows BC Hydro to make a reasonable comparison between tenders for evaluation purposes,
- enhances transparency by applying disclosed and well-defined evaluation criteria,
- avoids multiple, prolonged, expensive and potentially unsuccessful negotiations for BC Hydro and IPPs, and
- reduces contract administration costs and complexity by adopting standard form EPAs.

BC Hydro believes that a CFT process is best suited to achieving the objectives set out in section 2.7.2.3 (page 2-48) of the 2005 REAP.

Q17. Please briefly describe the proposed F2006 Call mandatory requirements.

A. Tenders will be required to meet certain mandatory requirements, which will be set out clearly in the CFT documents. The purpose of these requirements is two-fold: (1) to ensure only projects that can meet BC Hydro's most basic requirements are eligible to participate; and (2) to enable potential bidders to determine as early as possible whether their proposed project is suitable for tendering in this process. An early self-assessment will assist bidders who are unlikely to meet the CFT requirements to avoid unnecessary effort and expense, and will provide some certainty to bidders that they will be competing against *bona fide* projects that have a reasonable chance of being successfully completed following award of an EPA. Each of the mandatory requirements has been established to attract bidders that are capable of providing competitive and reliable supply.

The proposed mandatory requirements are summarized below. In each case, the table entitled "CFT Process – Mandatory Requirements", attached hereto and marked **Exhibit A**, contains further details concerning the rationale for each mandatory requirement, and comparisons to other jurisdictions.

- ***Project Location***: As with past calls, BC Hydro is requiring that projects be located in BC to ensure reliability and security of supply and to be consistent with the BC Energy Plan. Work on the 2004 IEP and 2005 Resource Options Report indicates that there are sufficient projects that can be developed in BC on a cost-effective basis.
- ***Technology/Project Type***: Eligible projects must use proven generation technology. All "proven" generation technologies, except nuclear technology, are eligible. No generation projects that received funding through a Load Displacement or DSM contract with BC Hydro are eligible. Existing generation facilities "inside the fence" of a customer's plant that did not receive funding through a contract with BC Hydro are also not eligible for this Call, unless those projects ceased to be synchronized to the transmission or distribution system prior to January 1, 2004.
- ***Project Size***: The minimum size of projects is 1 MW. EPA administration costs for small projects are high on a per unit of output basis. BC Hydro's experience has been that small projects require almost as much administrative time and effort as larger projects. With respect to projects under 1 MW, BC Hydro is currently exploring alternative processes that would accommodate such projects in a cost-effective manner.

- ***Exclusivity and Split Bids***: All Small Project output (net of station service) must be tendered to BC Hydro. Large Project bidders may elect to retain a portion of the project output for sale to third parties ("split bids"). Split bids should increase the pool of potential bidders by facilitating larger projects producing energy in excess of that which would be purchased by BC Hydro pursuant to the F2006 Call. This encourages competition in the CFT process, thereby reducing bid prices.

- ***Interconnection and Metering***: All projects located on the BC Hydro/British Columbia Transmission Corporation (BCTC) integrated transmission and distribution system will be eligible, with the exception of Fort Nelson. Projects that are not located within the system will be eligible but the point of delivery must be at a specified point on the system. Project output must be metered separately at the generator. Losses between the meter and the point of delivery will be deducted for payment purposes.

  Given the outcome of BCTC's Open Access Transmission Tariff (OATT) application, BC Hydro's intention is to require all bidders to have a completed preliminary interconnection study, including loss calculations, at the time of tender submission.

- ***No Current Contracts***: The energy tendered to BC Hydro must not be under contract to BC Hydro or to any other party during the term of the EPA.

- ***Tender Security***: In order to recognize that tenders must constitute irrevocable and legally binding offers, tenders must be accompanied by tender security in the form of an unconditional, irrevocable letter of credit issued by a creditworthy bank or financial institution in a prescribed form in the following amount:

  - Large Projects – $10,000 per MW (based on annual firm tendered energy in MWh divided by 8760), and

  - Small Projects – $5,000 per MW of maximum project capacity.

  Bidders who want to use a letter of credit in a form other than the prescribed form may seek BC Hydro's consent to an alternate unconditional, irrevocable form before tender submission.

  Tender security is set at a level sufficient to ensure that only serious bidders will participate in the CFT process. Tender security provides increased assurance of executed EPAs resulting from the CFT process.

There will be other mandatory requirements. Examples include bidder registration and fees, submission of tenders on time, completion of stipulated forms and unconditional bids. These requirements are standard for most tender processes.

Q18. Are there any other assessment criteria?

A. Yes, there are three other criteria for assessing submitted tenders, which are summarized below. Further details concerning the rationale for each of these three additional criteria, and comparisons to comparable jurisdictions, are contained in Exhibit A:

- ***Financial Strength*:** BC Hydro will assess bidders to ensure that they have, or have access to, appropriate financial strength to finance, develop and operate their project successfully. This assessment provides increased assurance that a project for which BC Hydro awards an EPA will be successfully completed.
- ***Bidder Experience*:** BC Hydro will assess bidders to ensure that they have, or have access to, sufficient relevant prior experience in developing, financing and operating power projects comparable to that proposed. This assessment provides increased assurance that a project for which BC Hydro awards an EPA will be successfully completed.
- ***Project Risk Assessment*:** BC Hydro will assess tendered projects to determine whether the projects pose an unacceptable level of risk with respect to project completion by the guaranteed COD or operation in accordance with the terms of the EPA. The assessment will take into account factors such as site control and tenure, permitting status, GHG mitigation plan, progress toward other project milestones, fuel supply arrangements and availability, and an assessment of the expected useful life of the proposed project consistent with the EPA term selected.

It is in the best interest of all parties that BC Hydro ensure that it does not award an EPA to a project that has a unacceptable level of project risk rather than relying on post-award contractual remedies if the project fails. The evaluation of a bidder's financial strength and development experience, and a project risk assessment, are common practices in the industry and are applied to help ensure that subsequent EPA awards are made to serious projects that can be relied on to deliver. This is in the best interests of all ratepayers.

Q19. What steps did BC Hydro take to ensure that the proposed F2006 Call mandatory requirements are not more stringent than the minimums needed?

A. BC Hydro took several steps to ensure that the proposed mandatory requirements are not overly stringent given BC Hydro's electricity needs.

First, BC Hydro completed a review of comparable acquisition processes, including mandatory requirements, from several jurisdictions in both Canada and

the United States. This review enabled a thorough assessment of how the proposed mandatory requirements (as well as terms and conditions) for the F2006 Call compared to the selection criteria used in other jurisdictions. BC Hydro developed the following criteria to assess whether an acquisition process was to be included in the assessment:

- Is the buyer a regulated utility?
- Is it an all sources process?
- Are the energy or other products being acquired comparable?
- Is the jurisdiction comparable?
- Is the acquisition process recent (i.e. post-2002)?
- Is there enough publicly available information to ensure a proper comparison?
- Is the acquisition process designed to acquire product for 10 or more years?

During the assessment process, BC Hydro reviewed at least 24 recent acquisition processes in 13 jurisdictions. As shown in **Exhibit F**, BC Hydro selected the acquisition processes of Puget Sound Energy, Xcel Energy (Public Service Company of Colorado), Hydro Quebec, PacifiCorp., Nova Scotia Power, Sierra Pacific/Nevada Power and Ontario Ministry of Energy because they met a variety of the criteria listed above.

Generally speaking, BC Hydro's proposed F2006 Call mandatory requirements, as well as its terms and conditions, are comparable to and consistent with those of the examined jurisdictions. It should be noted that each utility designs its CFT or RFP process to accomplish specific goals which may not be relevant or appropriate to the F2006 Call context.

Second, BC Hydro proposes to give bidders a range of tendering options that will enable them to build on the strengths of their projects and thereby deliver cost effective projects while preserving sufficient comparability of tenders for evaluation purposes. Some of the key bidder options include:

- ***Split Bids:*** Large Project bidders have the option to tender all or part of the output of their project to BC Hydro. By allowing split bids for larger projects, the terms of the F2006 Call facilitate larger projects producing energy in excess of that which would be purchased by BC Hydro pursuant to the F2006 Call, thereby increasing the pool of potential bidders and competitive tenders.
- ***Term Flexibility*:** Bidders will be permitted to select an EPA term of 15, 20, 25, 30, 35 or 40 years. Allowing bidders greater term flexibility should encourage more bidders to participate in the F2006 Call process, thereby

encouraging bidders to provide BC Hydro with reduced costs in return for long-term EPAs that are appropriate for the resource being offered. Bidders are in the best position to determine the optimum term length. Further details concerning the rationale for flexible contract term, and a comparison with the selected jurisdictions, are set out in the table entitled "EPA Terms and Conditions", attached as **Exhibit C**.

- ***COD Timing Flexibility:*** Bidders will be permitted to bid a guaranteed COD between October 1, 2008 to October 1, 2009. With respect to early COD, some bidders indicated that they would be in a position to implement a more cost-effective project with an earlier in-service date. Accordingly, bidders will be permitted under the EPA to achieve COD up to 12 months in advance of the guaranteed COD but no earlier than January 1, 2008. Further details concerning the rationale for COD timing flexibility, and a comparison with the selected jurisdictions, are set out in Exhibit C. The COD timing is established so that BC Hydro has delivery certainty to ensure that a selected tender can be relied on to be available to meet load requirements.
- ***Hourly Firm*:** Large project bidders will be permitted to elect the hourly firm option and will receive a $3/MWh evaluation credit reflecting the additional value relative to other projects.
- ***Green Attributes*:** As discussed above, bidders will be permitted to elect to assign the Green Attributes to BC Hydro and receive a $3/MWh evaluation credit, reflecting the additional value relative to other projects.
- ***Pricing After Initial Term*:** Bidders that elect an EPA term greater than 15 years will have the option to bid a lower price to become applicable after the 15th year (or such longer period as selected by the bidder), allowing for pricing options that facilitate increased competition.
- ***Energy Profile:*** Large Project bidders will tender a firm energy profile (monthly or hourly) to reflect their specific project characteristics. This will provide bidders with the opportunity to optimize the risk/reward balance for their projects in conjunction with the terms and conditions of the CFT and EPA, allowing for more competitive bids.

There are additional terms and conditions which may facilitate a larger pool of bidders and more competitive pricing, such as caps on liability, as discussed below and addressed in greater detail in Exhibit C.

Q20. Are there any proposed restrictions on resource types?

A. The F2006 Call is an "open" CFT, meaning that all proven generation technologies, except nuclear technology, are eligible. Pursuant to the BC Energy Plan, BC Hydro will not accept any proposal based on nuclear technology.

Q21. How does the F2006 Call propose to address the 50%"BC Clean Electricity" goal?

A. Consistent with Policy Action #20 of the BC Energy Plan, BC Hydro is targeting for a portfolio consisting of 50% "BC Clean Electricity". The BC Energy Plan (page 32) defines "BC Clean Electricity" as follows:

> "BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small/micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and energy efficiency at existing facilities".

In contrast to recent calls which were restricted regionally or to green or customer-based generation sources, this is an open CFT in which BC Hydro will select cost-effective supply from all sources with the objective of meeting its 50% BC Clean Electricity target. In applying the 50% target, BC Hydro will be guided by the BC Energy Plan which contemplates the possibility that initiatives to acquire BC Clean Electricity may raise electricity rates by up to 0.1% to 0.2% over the upcoming decade. Further details are provided in the table entitled "Tender Evaluation Criteria and Methodology", attached hereto and marked **Exhibit B**.

Q22. Are there any other material evaluation adjustments or constraints in the F2006 Call respecting resource types which are not described elsewhere in this testimony?

A. No. BC Hydro is seeking to encourage an active competition amongst all sources of supply (except nuclear) capable of meeting the mandatory requirements and providing cost-effective electrical energy.

Key Terms and Conditions

Q23. What is the purpose of this section of your evidence?

A. BC Hydro recognizes that the relative cost-effectiveness of projects that pass the mandatory requirements and other assessment criteria described above, and ultimately are awarded EPAs, is influenced by the terms and conditions of the contractual arrangement and how the identifiable risks are allocated between the parties to the EPA. This section identifies the key terms and conditions proposed by BC Hydro, including how BC Hydro plans to allocate the underlying risks and why the risks have been allocated in such manner.

Where there is a difference in risk allocation between Small Projects and Large Projects, I will identify the difference, and how such allocation of risk will lead to the most cost-effective outcome, including process/transaction costs.

Q.24 Are the key terms and conditions generally consistent with commercial and legal terms and conditions in long-term supply arrangements used by other utilities in procuring electrical energy?

A. Yes. As described above, BC Hydro completed a review of other acquisition processes, including EPA terms and conditions, from various jurisdictions in both Canada and the United States. That review confirmed that BC Hydro's proposed key terms and conditions are in general alignment with these jurisdictions. Exhibit C contains further detail concerning the comparison with the selected jurisdictions.

It should be noted that each EPA in each jurisdiction must be viewed based on the nature of the product the buyer wishes to acquire under the proposed agreement. There are different types of electricity products. Each product results in different contractual terms and conditions and allocation of risk. In addition, the allocation of risk under each contract must be viewed as a whole. While BC Hydro may be more stringent than some jurisdictions on some issues, it is less stringent on other issues. In developing the form of EPA for the F2006 Call, BC Hydro first identified the product it needed to acquire. BC Hydro then developed a set of terms and conditions that would secure delivery of that product. BC Hydro checked those terms and conditions against contracts in other jurisdictions to ensure that, taken as a whole, the proposed risk allocation is aligned with other jurisdictions.

The result is a Call designed to optimize the balance of the allocation of risk between BC Hydro and successful bidders in order to obtain the most cost-effective result for BC Hydro's ratepayers.

Q25. In formulating the proposed F2006 Call terms and conditions, was consideration given as to who can best reduce or eliminate particular risks, and who can best price, manage and mitigate particular risks?

A. Yes. BC Hydro gave consideration to how risk should be allocated between BC Hydro and successful bidders, including considering who can best reduce or eliminate particular risks, and who can best price, manage and mitigate particular risks, such that this risk allocation will support a cost-effective outcome and hence will benefit ratepayers.

Q26. With respect to the key risks, please describe the proposed risk allocation, and on what basis it was decided to apportion the risks.

A. The following are the key risks. In each case, risk has been allocated between BC Hydro and the successful bidder in order to obtain the most cost-effective result for BC Hydro's ratepayers. Further details concerning the rationale for the proposed risk allocation are found in Exhibit C:

- ***Small Project Energy Price and Large Project Firm Energy Price*** – The pricing structure is a fixed $/MWh price (adjusted for time of delivery) tendered by the bidder rather than a price tied to a market index. From BC Hydro's perspective, it is appropriate to purchase energy at fixed prices because such pricing is better matched to BC Hydro's fixed rate schedule and limits the need for future rate increases arising from long-term contracted supply to meet long-term load requirements. From the successful bidders' perspective, the proposed pricing provisions address the risk that successful bidders would have more uncertain revenue streams if prices were tied to market indices, which would increase the difficulty of obtaining cost-effective equity and debt financing.
- ***Large Project Non-Firm Energy Price*** – With respect to Large Projects , non-firm energy will be subject to stepped discounts as volume increases. As shown in Exhibit C, for the first tier of non-firm energy, BC Hydro will purchase a fixed amount of non-firm energy at a discounted fixed price, and for the remaining non-firm energy, BC Hydro will purchase energy at a market based price, but capped at the first tier non-firm energy price. The non-firm pricing provisions address the risk that absent such provisions BC Hydro would pay the same price for a lesser value energy product. In providing non-firm pricing terms, BC Hydro acknowledges that an appropriate amount of non-firm energy can be a cost-

effective supplement to firm energy. The majority of comparable jurisdictions have some form of price discount for excess energy.

- ***Price Escalation*** – The bidder will tender a percentage of the bid price (between 0 and 50%) that escalates with the CPI. The escalation provisions are designed to address the risk that the revenue stream (to the extent impacted by the price paid) for the energy does not match the bidder's cost stream. Allowing bidders to specify escalation provisions is a way of addressing revenue risk and uncertainty in a way that limits the exposure for BC Hydro's ratepayers. Successful bidders are in a better position than BC Hydro to manage their cost of production and to estimate their future costs. BC Hydro anticipates that for most projects the majority of the project costs will be capital costs and associated financing costs.
- ***COD Timing*** – Bidders can elect a guaranteed COD between October 1, 2008 and October 1, 2009. A successful bidder may achieve COD up to 12 months in advance of the guaranteed COD, but no earlier than January 1, 2008. BC Hydro proposes to allocate the risk of late COD and/or COD failure to successful bidders as successful bidders are the party best able to reduce or mitigate the risk of COD delay and failure. Timing risk, and the associated engineering, procurement, construction and commissioning, should be the responsibility of the bidder. A 180-day grace period has been included with respect to liquidated damages (LDs) resulting from late COD to allow some flexibility to successful bidders who encounter short-term development delays. Allowing COD flexibility with ultimate date-certain delivery, facilitates more active competition for cost-effective supply with bidders being able to optimize their timing in order to provide cost-effective and reliable supply.
- ***Contract Term –*** As discussed above, bidders will be permitted to select an EPA term of 15, 20, 25, 30, 35 or 40 years. Allowing bidders greater flexibility should attract more bidders to participate in the F2006 Call process, therefore increasing competition and contributing to lower prices.
- ***Changes in Law/Flow Throughs*** – There is no price change, cost reimbursement, termination or re-negotiation right arising from a change in law, nor will there be any cost flow throughs to BC Hydro with the exception of a partial flow through for changes in the property tax rate. BC Hydro is proposing that any changes in the amount of property tax payable as a result of a change in the property tax rate be equally shared between BC Hydro and the successful bidder. Any changes in the amount of property tax payable as a result of a change in the assessed value of the property will be the responsibility of the successful bidder. BC Hydro will not accept fuel (including natural gas) price risk or offer any tolling arrangements. BC Hydro has provided some options regarding GHG regulatory risk (discussed below). Bidders can select up to 50%

of their bid price to escalate at 100% of CPI to address general increases in costs during the term. Such a provision limits ratepayer exposure and ensures that successful bidders will be incented to take proactive action against adverse changes in law rather than merely passing costs through to ratepayers. With the exception of one jurisdiction with respect to carbon dioxide risks, none of the selected jurisdictions provides any change in law relief, except to the extent change in law prevents performance (force majeure).

- ***GHG Emission Offsets*** – With respect to meeting GHG regulatory requirements***,*** bidders will have the option of (1) retaining all GHG liabilities including GHG emission offset obligations or (2) transferring their GHG emission offset obligations to BC Hydro, but retaining all other GHG liabilities. If the GHG offset risk is transferred to BC Hydro, evaluation adjusters will be applied to the bid prices based on the tendered EPA term and the GHG intensity of the projects (see Exhibit B for details). The bid price adjustment reflects BC Hydro's estimate of the potential future cost of GHG offset obligations. The Direct Testimony of Tim Lesiuk, Richard Rosenzweig and Doug Russell addresses how and why BC Hydro arrived at these evaluation adjusters. Also, further details of the risk assessment for GHG liabilities are provided later in my testimony. In the case of (2), BC Hydro's obligation is limited to the GHG intensity tendered by the bidder, and the bidder would retain all other GHG-related liabilities (e.g., a carbon tax on fuel or emissions). Providing bidders with an option for handling GHG emission offsets allows them to choose the most economic alternative and thereby tender more cost-effective prices to BC Hydro.

- ***Liquidated Damages* (*LDs)*** – BC Hydro proposes two LD provisions, namely, COD delay LDs, and shortfall LDs for firm energy, both applicable only to Large Projects. The COD delay LDs become effective 180 days after the guaranteed COD. The daily amount is 1/180 of the performance security amount payable for an additional 180 days. Thereafter, no further delay LDs are payable; however, BC Hydro may elect to terminate the EPA if the delay continues. Bidders are in the best position to manage the risk of COD delays. The shortfall LDs for both monthly and hourly firm delivery shortfalls are mark-to-market LDs based on a comparison of the adjusted bid price to the Mid-Columbia (Mid-C) price (capped at $100/MWh escalating at CPI), plus transmission charges from Mid-C to the border. The successful bidders are in the best position to manage the risk of fluctuations in output for their projects. BC Hydro is proposing a cap on the Mid-C price, which in turn limits shortfall LD liability, in order to remove some of the risk that may otherwise increase the financing cost of some projects, resulting in lower bid prices.

- ***Security*** – BC Hydro proposes that Large Project bidders post an unconditional, irrevocable letter of credit in the amount of $60,000/MW of project capacity.

Large Project letters of credit will be reduced to $40,000/MW (based on annual firm energy divided by 8760) on the first anniversary of COD. Small Project bidders must post an unconditional, irrevocable letter of credit in the amount of $30,000/MW of project capacity, which is released on the first anniversary of COD. These security provisions ensure that bidders are capable of backing their delivery obligations and address the risk that the successful bidder may not pay the applicable LDs, other damages or termination payments. The security is set at an appropriate level to reflect the risk to BC Hydro and its ratepayers without burdening IPPs with significant carrying costs.

- ***General Limit of Liability*** – For Small Projects, the overall annual limit of liability is equal to $30,000/MW of project capacity, except for deliberate breaches. For Large Projects, the overall annual cap on liability for all LDs and other breaches of the EPA, except for deliberate breaches, is equal to 200% of the performance security amount. These proposed limits of liability result in a sharing of the risk. BC Hydro believes that it is appropriate to offer an overall annual limit of liability to remove some of the risk that may limit the financeability of projects, thereby increasing the pool of competitive bids.
- ***Seller Termination Pre-COD*** – With respect to Large Projects, the successful bidder can terminate if material permits are not obtained at least 18 months prior to guaranteed COD. This termination option is dependent on the successful bidder demonstrating reasonable efforts to obtain such permits and is further conditioned on the successful bidder paying a defined termination fee. With respect to Small Projects, the successful bidder can terminate for any reason up to the first anniversary of EPA signing. The termination fee for Large Projects is $20,000/MW based on annual firm energy (in MWh) divided by 8760, and for Small Projects is $10,000/MW of project capacity. Other termination rights are discussed in Exhibit C. By not requiring material permits prior to tender submission, a larger number of bidders will likely be eligible to provide bids, thereby increasing the competitive pool and lowering power prices. The prescribed pre-COD termination rights should help ensure that only serious bidders capable of attaining COD in a timely manner will submit tenders.
- ***Fuel Price and Supply Risk*** – BC Hydro will not accept fuel price risk, including natural gas pricing, or offer any tolling arrangements. Successful bidders will be required to take full fuel cost and supply risk thereby limiting ratepayer exposure to fuel price and supply risk variability.
- ***Availability and Reliability*** – For the F2006 Call, the primary availability and reliability issue is centered on the proposed acquisition of firm supply. The characteristics of the firm product, including the rationale for the requirement for

firm energy, the appropriateness of the risk allocation and its valuation, have been described earlier in my evidence.

GHG Emissions

Q27. Should BC Hydro expressly address the risk allocation for future regulatory compliance costs for GHG emission offsets in its F2006 Call bid evaluation?

A. Yes. It would be imprudent for BC Hydro not to do so, for the reasons set out in the Direct Testimony of Tim Lesiuk and Richard Rosenzweig. Natsource's review of multiple GHG cost studies and modeling results found that $19 to $50 per tonne was a reasonable range for projected compliance costs with future GHG regulation in 2015. Even at the low end of the range of estimates, the potential cost impacts could be substantial. Different resource options have different GHG emission profiles. Assuming that future GHG compliance costs are correlated with GHG emission levels (see the Direct Testimony of Doug Russell), those different resource options are exposed to varying levels of risk of future regulatory costs, depending on their GHG emission rates and other factors. Unless this risk variation for future GHG compliance costs is reflected in the CFT process, BC Hydro could end up selecting a F2006 Call portfolio that is not cost effective on a risk-adjusted basis.

The term “GHG emission offsets” is broadly defined here to mean the range of activities that result in emission reductions, emission avoidances and increases in emission sinks, as well as the various emission trading mechanisms (e.g. allowances, credits) that have been established under the Kyoto Protocol or may be established under the federal climate change plan. BC Hydro expects that future GHG emission regulations will include more prescriptive provisions respecting the description and nature of GHG emission offsets.

Q28. How will projects that are in service prior to Kyoto Protocol implementation be treated in the F2006 Call?

A. All EPAs awarded under the terms of the F2006 Call will require the successful bidder to comply with all Canadian federal, provincial and municipal regulatory regimes for GHG emissions regardless of whether or not the regimes are otherwise applicable to the projects, based on the timing of COD or any other date stipulated in the regulations. Currently it is anticipated that the federal requirement will be tied to “Best Available Technology Economically Achievable” (currently anticipated to be set at 85% to 100% of the GHG emissions of a combined cycle generation turbine (CCGT) facility) standard. The 100% CCGT standard has been imposed by Alberta’s Energy and Utilities Board in respect of two approved coal-fired plants.

Q29. Please explain why treatment of GHG emission offset risk in the F2006 Call is important for managing BC Hydro's exposure to financial and development risks.

A. As mentioned above, even at the low end of a range of reasonable estimates of potential GHG regulatory compliance costs, the costs of complying with future GHG regulations could be substantial. The potential magnitude of compliance costs in moving from the low end of the range of cost estimates to the high end, raises concerns about the impact on the financial integrity of the entity required to shoulder the risk – whether it is an IPP, a utility or ratepayers. For thermal technologies, compliance with GHG regulations is likely to become a material component of the total cost of energy.

Q30. How can the F2006 Call competitive bidding process be shaped to allocate and manage GHG emission offset risks?

A. There are a range of approaches that could be used within the F2006 Call competitive bidding process to allocate and manage GHG risk, each of which has its own set of advantages and disadvantages. Among the risk allocation mechanisms available are:

(1) The F2006 Call documents could simply not address the issue. Because it ignores the potential risks and costs of future GHG regulations, this approach would not be prudent.

(2) The F2006 Call documents could assign responsibility to successful bidders of any and all future GHG regulatory and legal requirements, with bidders internalizing GHG risk into their bid prices. One major drawback of this allocation of GHG risk is that by shifting responsibility for anticipating future GHG costs from BC Hydro to the successful bidders, it trades off GHG risk for contract performance risk. If a particular successful bidder underestimates the GHG risk or does not adequately internalize that risk into the bid price, it could affect the incentive and ability of the successful bidder to perform its obligations under an EPA. This approach might result in a higher cost to ratepayers if successful bidders lack the expertise to price and manage risk, as BC Hydro may be able to manage a larger portfolio of GHG offset requirements in an integrated fashion at lower cost than any one project.

(3) BC Hydro could assume responsibility for any future GHG regulatory and legal requirements, with the understanding that BC Hydro would apply an evaluation adjuster to the bid price based on the tendered GHG intensity of the projects. One potential disadvantage to this approach is that some bidders may

be able to better price and mitigate the GHG risk than BC Hydro. Therefore the ratepayer would not benefit from the least cost solution.

(4) Bidders could be given the option of (a) assuming responsibility for any and all future GHG regulatory and legal requirements and bidding a contract price that internalizes GHG risk into their bid prices; or (b) having BC Hydro assume responsibility for one type of future GHG regulatory risk (the regulatory requirement to purchase offsets), with the understanding that BC Hydro would apply an evaluation adjuster to the bid price based on the tendered GHG intensity of the projects. In the case of (a), the risk allocation described in (2) above is applicable. In the case of (b), BC Hydro's obligation would be limited to the GHG intensity guaranteed by the bidder in its tender, and the bidder would retain all other types of GHG risk. If the successful bidder's facility exceeds the guaranteed GHG intensity, it would be responsible for the excess offset costs. This is the allocation of GHG liability that BC Hydro proposes for the F2006 Call.

Q31. Please describe why and how BC Hydro proposes to allocate and assess the GHG emission offset risk in the F2006 Call.

A. As described above, bidders would elect whether to bid in a price that includes internalization of the full GHG risk. Providing the bidder with the choice creates opportunities for lower-cost options for hedging GHG risk that may not otherwise be identified or pursued under alternative (3) as described in Q30. This approach is a hybrid of alternatives (2) and (3) as described in Q30. This was the approach taken by PacifiCorp in its most recent RFP process.

If the bidder does internalize the full GHG risk into its bid price, it would not be assessed the GHG bid adjuster for tender evaluation purposes. To the extent that a bidder believes that it can internalize the GHG offset risk at a cost lower than the BC Hydro's GHG bid adjuster, it will presumably exercise this option in developing its bid.

If, instead, a bidder elects not to internalize the GHG offset risk into its bid price, it would submit the proposed GHG intensity of its facility with its tender. For bid evaluation purposes only, the GHG bid adjuster will be added to the bid price. The GHG bid adjuster is based on the tendered GHG intensity of the project and the EPA term (see "GHG Bid Adjuster Look-up Table" at the end of Exhibit B).

Examples of GHG evaluation adjusters include the following:

- Coal-fired electricity generating facilities commonly emit 0.8 to beyond 1.2 tonnes of carbon dioxide equivalent/megawatt hour (t CO_2e/MWh). Thus, the GHG bid adjustment for a coal-fired generation project with an EPA term of 25 years would range between $13 to $23/MWh, depending on the project's emission profile;

- Single cycle (SCGT) natural gas fired electricity generating facilities commonly emit 0.4 to 0.7 t CO_2e/MWh. The GHG bid adjustment for a SCGT project with an EPA term of 25 years would range between $3 to $10/MWh, depending on the project's emission profile;

- CCGT facilities commonly emit 0.3 to 0.4 t CO_2e/MWh. The GHG bid adjustment for a CCGT project with an EPA term of 25 years would range between $2 to $3/MWh, depending on the project's emission profile.

F2006 Call Process

Q32. What is the purpose of this section of your evidence?

A. The purpose of this section is to identify the process that will be used in the F2006 Call. It will also identify the steps that have been taken to minimize transaction costs while allowing BC Hydro to reasonably manage process-related risks to obtain the most cost effective result for BC Hydro's ratepayers.

Q33. Please provide a step-by-step outline of the F2006 Call process, from the submission of bids to the awarding of EPAs.

A. The CFT consists of a single stage of approximately 6-8 months duration following the formal issuance of the CFT. There will be no preliminary or separate pre-qualification stage for bidders or for projects. A single stage process will simplify the process, shorten the period from the CFT to the EPA award, and is expected to reduce costs for both BC Hydro and IPPs. None of the comparable jurisdictions have a preliminary pre-qualification stage.

The F2006 Call will be divided into two streams. The first stream is for Small Projects and the second stream is for Large Projects. Mandatory requirements and evaluation criteria for each stream will be set out in the CFT document and will enable bidders to determine at an early stage whether or not they wish to participate. This too is expected to reduce transaction costs.

Upon receipt of tenders, BC Hydro will follow the following evaluation process:

Step One – BC Hydro will first assess the tenders to determine whether they conform with the CFT requirements (e.g. correctly signed, compliant tender security amounts and form, all material information completed, energy profile compliant with applicable rules). Consistent with applicable law and good tendering practice, materially non-conforming tenders will be rejected.

Step Two – BC Hydro will then assess bidders and projects to ensure compliance with the mandatory requirements. The mandatory requirements are discussed above.

Step Three – For those tenders that comply with the mandatory requirements, BC Hydro will assess the Bidders to confirm that they are reputable and they have, or have access to:

- appropriate experience in power project development and operation, and
- appropriate financial strength.

Concurrent with this assessment of the bidders, BC Hydro will also carry out a project risk assessment for each tender. The project risk assessment will involve consideration of:

- the likelihood that the project or projects described in the tender can achieve COD by the guaranteed COD selected by the bidder, having regard to the status of permitting, site acquisition, design, engineering and procurement and other critical project development activities; and
- the likelihood that the project or projects described in the tender can deliver the contracted energy output for the full EPA term selected by the bidder, having regard to the expected useful life of generation equipment, the term of site tenure arrangements and applicable permits, GHG mitigation plan, fuel supply arrangements and other critical project elements.

Step Four – Qualified tenders will be evaluated in accordance with the evaluation methodology described in Exhibit B.

BC Hydro will reserve the right in its discretion to cancel the CFT process before award of any EPA, and to award no EPAs.

Bidders who are awarded an EPA will be required to sign and deliver the EPA, together with the specified performance security to BC Hydro within a short time after delivery of the final form EPA to the bidder for signature, failing which BC Hydro will be entitled to draw on the bidder's tender security.

Q34. Why is BC Hydro proposing a separate stream for Small Projects in the F2006 Call?

A. BC Hydro has provided a separate stream for Small Projects based on input received from IPPs, First Nations and other stakeholders. Based on the results of past calls, BC Hydro believes that a significant amount of cost-effective energy is available from small projects.

The inclusion of two separate "streams" in the F2006 Call with a different evaluation methodology and form of EPA recognizes the differences in project size, complexity and risk. The Small Project stream will allow smaller projects to be bid competitively within the CFT and allow BC Hydro to acquire cost-effective resources while reducing unnecessary transaction and ongoing administration costs.

Q35. Please briefly describe the key features of the proposed evaluation methodology.

A. There are four main phases to the evaluation, as follows:

- initial assessment ,
- price levelization,
- determination of adjusted bid prices, and
- determination of optimal portfolio.

Phase 1 is described above in my answer to Q33.

Phase 2 involves calculating the levelized bid price for those tenders passing Phase 1. Tenders with stepped pricing will be subject to an Initial Period Price Constraint, which limits the amount of "front end loading" that BC Hydro will accept in the pricing.

Phase 3 involves adjusting the levelized bid prices to represent the delivered cost of a common electrical product to a common delivery point. In the case of Small Projects, the common product is non-green energy, risk-adjusted for any GHG emission offset risk borne by BC Hydro. In the case of Large Projects, the common product is non-green monthly-firm energy, risk-adjusted for any GHG emission offset risk borne by BC Hydro. In the case of both streams, the common delivery point is the Lower Mainland. The mechanism for adjusting the bid prices to the Lower Mainland will reflect the outcome of the recent Commission decision on the OATT; hence the description of this part of the methodology is deferred, pending a full evaluation of that decision. The specific bid price adjusters are described further in Exhibit B.

Phase 4 involves, for each stream, the identification of the optimal portfolio of one or more tenders that have passed Phases 1, 2 and 3 above, having regard first to both price factors and then to non-price factors. The selection of the optimal portfolio will take into account BC Hydro's commitment to acquiring low-cost BC Clean Electricity to meet the BC Energy Plan goal, based on adjusted bid price. BC Hydro reserves the right to consider a number of non-price factors, as further described in Exhibit B, when selecting the optimal portfolio. The resulting portfolio is expected to reflect a cost-effective combination of tenders for BC Hydro's ratepayers. Differences in selection of the optimal portfolio between the two streams are also highlighted in Exhibit B.

Q36. How does the F2006 Call process minimize transaction costs while allowing BC Hydro to reasonably manage process-related risks?

A. In addition to the separation of the F2006 Call into two streams, several F2006 Call process measures are proposed in order to yield a cost-effective solution while minimizing transaction costs. The following are some examples:

- use of a single-stage CFT process without a pre-qualification phase,
- increased requirement for bidder self-assessment,
- need for bidders to submit their energy profile,
- no split bids allowed for Small Projects,
- requirement for completed interconnection studies, and
- minimum project size of 1 MW.

Q37. What steps has BC Hydro taken to ensure call transparency and openness?

A. In the interests of transparency and obtaining Bidder input in a cost-effective way, BC Hydro proposes that the CFT, all addenda and all other documents to be issued to Bidders will be posted to a publicly available website. A question and answer (Q & A) process will be hosted on the website for the use of all registered Bidders. All CFT documents and Q & A material will be available for viewing on the website by all interested parties. The CFT process will include a bidder workshop to assist registered bidders in understanding CFT requirements. Furthermore, bid prices of all successful and unsuccessful tenders will be published on our website after EPA award(s), as well as any non-price factors that may have been used in determining the optimal portfolios.

First Nations and Stakeholder Consultation

Q38. What steps has BC Hydro taken to ensure First Nations and stakeholders are afforded the opportunity to provide meaningful input into the proposed F2006 Call?

A. The F2006 Call expands BC Hydro's previous practice of obtaining input on CFT elements from potential bidders to explicitly seek input from First Nations, stakeholders and customers. Specifically, in the initial pre-CFT engagement phase, BC Hydro has:

- provided regional opportunities for dialogue and input through four regional sessions, followed by one technical workshop. First Nations, municipal governments, the provincial government, potential bidders from local, national and international companies, customer groups and energy and engineering consultants attended these sessions,

- hosted face-to-face and teleconference meetings with customer groups including the Joint Industry Electricity Steering Committee, West Fraser Mills Ltd., the Commercial Energy Consumers of British Columbia, the BC Old Age Pensioners Organization, and the Independent Power Producers Association of British Columbia, and

- used the website for timely document distribution and written comments.

Q39. To date, how has BC Hydro handled and responded to comments received from First Nations and stakeholders?

A. BC Hydro circulated a structured comment form as part of its First Nations and stakeholder engagement process to enable BC Hydro to use the review time to consider the substance of the comments and the range of possible solutions. Comments were submitted or documented in meetings on the proposed CFT process, evaluation, pricing and contracting terms. Meeting participants also provided positive and constructive feedback on the engagement process itself, providing BC Hydro with important information with which to continuously improve its engagement process, both for this Call and for other initiatives.

A broad technical, commercial and legal team reviewed and revised the proposed F2006 Call elements, taking into account the comments received, minutes from the regional and technical sessions, the characteristics of BC Hydro's forecast energy needs, past comments and decisions from the Commission, and the overall balance and interrelation between the Call

parameters themselves. In response to comments received, several changes were incorporated, including: term flexibility, non-firm pricing provisions, split bids, changes to security, and LD requirements.

BC Hydro intends to solicit further comments following the issuance of the draft forms of the CFT documents, before the CFT is formally issued.

Conclusion

Q40. Will F2006 Call mandatory requirements, if implemented as intended, together with the key terms and conditions and call process, result in a cost-effective outcome?

A. Yes, barring an unforeseen event, BC Hydro fully expects that the F2006 Call will be successful and result in the acquisition of cost-effective electrical energy.

Q41. Does that conclude your evidence?

A. Yes.

CFT Process – Mandatory Requirements

July 8, 2005

Notes:

- ***This Exhibit has been prepared for filing in a regulatory proceeding. The final CFT and EPA will be the governing legal documents between BC Hydro and Bidders/Successful Bidders, and this Exhibit will have no contractual legal effect.***

- ***For a list of the selected jurisdictions and associated power procurement processes see Exhibit "F" to the Direct Testimony of Mary Hemmingsen.***

No	Requirement	Rationale	Comparison with Selected Jurisdictions
1	**Project Location** Projects must be located in British Columbia.	It has been BC Hydro's long-standing practice to encourage the development of domestic electricity supply to ensure reliability and security of supply. This is consistent with the BC Energy Plan, which clearly provides that IPPs will develop new electricity generation in BC (Policy Action #13). Work on the 2004 IEP and 2005 Resource Options Report indicates that there are sufficient projects that can be developed in BC on a cost-effective basis such that this requirement will not adversely affect the cost-effectiveness of this Call.	Selected Canadian jurisdictions generally require that generation facilities be located within the procuring province. Selected U.S. power procurement processes generally do not require that projects be located in a specific geographic area.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
2	**Technology/Project Type** Subject to compliance with other mandatory requirements, all "proven" generation technologies and project types (except nuclear projects) are eligible. "Proven" technologies are generation technologies, which are proven, readily available in commercial markets and in commercial (not demonstration) use, as evidenced by at least 3 generation plants generating energy for a period of not less than 3 years, to a standard of reliability generally required by good utility practice and the standard required under the proposed EPA for this Call. Prototype and near-commercial technologies are not eligible for this Call. "Incremental generation" from existing facilities is eligible provided that the incremental generation can be metered separately. No generation projects that received funding through a Load Displacement or DSM contract with BC Hydro are eligible. Existing generation facilities inside the customer's plant fence that did not receive funding through a contract with BC Hydro are also not eligible for this Call unless those projects ceased to be synchronized to the transmission or distribution system prior to January 1, 2004.	*Reduces Project Risk* - BC Hydro requires a reasonable level of assurance that projects awarded EPAs are able to supply energy as anticipated. *Reliability of Supply* – Limiting the CFT to proven technologies supports BC Hydro's objective of supply certainty and security. Existing Load Displacement projects do not add any additional energy to the system and therefore should not be permitted to "trade up" from their existing payment structure to a higher payment structure in the CFT process.	All selected jurisdictions include some level of technology evaluation in their selection process. Several jurisdictions expressly state that technology must be proven or they prohibit demonstration technologies.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
3	**Minimum Project Size** The minimum size of projects in this Call is 1 MW.	*Reduces Transaction Costs* – The EPA administration cost for small projects is significant on a per MW basis. BC Hydro's experience has been that small projects require almost as much administrative time and effort as larger projects. BC Hydro chose the 1 MW minimum size because the technical interconnection requirements for units above and below 1 MW are different. With respect to projects under 1 MW, BC Hydro is currently exploring alternative processes that would accommodate such projects in a cost-effective manner.	There is no uniform practice on the issue of minimum project size. A number of selected jurisdictions impose a minimum project size (e.g. PacifiCorp – capable of delivering 70,000 MWh per year; Ontario – 2004 Renewables RFP .5 – 100 MW; Ontario 2005 Draft RFP – contract capacity 20 MW – 200 MW).

No	Requirement	Rationale	Comparison with Selected Jurisdictions
4	**Energy Profile** **<u>Large Project Stream:</u>** All bidders in the large project stream will be required to tender a firm energy profile which will determine the amount of energy the Bidder is contractually obligated to deliver either on a monthly basis or on an hourly basis (for those bidders that elect the hourly firm option). The tendered energy profile will be contractually binding throughout the term of the EPA. The total aggregate amount of firm energy that a project in the large project stream can supply during April, May, June and July is limited to a maximum of 1/3 of the annual firm energy tendered. BC Hydro will accept energy in excess of this limit during this period but such energy will be subject to a discounted price. **<u>Small Project Stream:</u>** Bidders in the small project stream are not required to tender an energy profile as bidders in that stream are not committed to provide a minimum volume of energy on a monthly/hourly basis.	**<u>Large Project Stream:</u>** *Reliability of Supply* – In this Call, BC Hydro is seeking to acquire firm energy – i.e. energy that the successful bidder is contractually committed to provide within a specified period. The energy profile supports this contractual commitment. From the bidders' perspective, the energy profile allows bidders to tailor their contractual commitment to meet the expected output levels from their facilities. *Reduces Transaction Costs* – The requirement for bidders to provide an energy profile (together with the pricing structure discussed in Exhibit "C") allows BC Hydro to compare the bid prices of projects with different energy profiles based on the bidders' self-assessment of their energy output. This avoids BC Hydro having to assess the "firmness" of the output from individual projects and apply individual bid price adjustments. This reflects BC Hydro's view that bidders are in a better position than BC Hydro to assess the output from their projects. *Cost-effective* – The April – July constraint on firm energy deliveries mitigates the risk that bidders will provide a disproportionate amount of their firm energy at times when BC Hydro may be experiencing minimum generation constraints. Given the constraints of the existing BC Hydro system, if BC Hydro does not impose reasonable restrictions on energy deliveries in April, May, June and July, BC Hydro will likely have to impose more significant restrictions during that period in future calls, thereby potentially limiting the types of products that could meet future call restrictions. **<u>Small Project Stream:</u>** *Transaction Costs* - BC Hydro has not required small projects to tender an energy profile on the grounds that the administrative burden and cost to monitor energy deliveries and to administer liquidated damages provisions is not justified given the size of the projects.	Most of the selected jurisdictions require some level of generation commitment. In the case of energy projects, that commitment tends to be on an annual basis. However, there are some examples of more stringent energy delivery commitments (e.g. Sierra Pacific – Long-Term Firm – hourly delivery rate required with LDs assessed on a monthly basis). In addition, those jurisdictions that have annual delivery commitments tend to impose more significant liabilities on sellers for failure to meet that commitment. None of the selected jurisdictions have a restriction similar to BC Hydro's April to July restriction. Some jurisdictions have physical caps on the buyer's purchase obligation or a discounted price for excess power deliveries or no payment obligation beyond a cap.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
5.	**Exclusivity** For both Large and Small Projects, the energy tendered to BC Hydro must not be under contract to BC Hydro or to any other party during the term of the EPA. **Small Projects:** All project output (net of station service) must be tendered to BC Hydro under the CFT. **Large Projects:** Bidders may elect to retain a portion of the project output for sale to third parties. Hourly firm bidders that elect the "split bid option" (thereby retaining a portion of their output for sale to third parties), will be required to tender a Split Bid Threshold Level (HLH and LLH MWh/h delivery rate for each month) at or above their hourly firm delivery rate. Energy produced in excess of the Split Bid Threshold Level would not be sold to or purchased by BC Hydro under the EPA. Monthly firm bidders that elect the split bid option would tender a Split Bid Threshold Level (MWh/h delivery rate for each month) at or above their average firm delivery rate. Energy produced in any hour in excess of the Split Bid Threshold Level would not be sold to or purchased by BC Hydro under the EPA. For either the hourly firm or the monthly firm bidder, to the extent that the Split Bid Threshold Level exceeds the firm energy amount, there is no liability for failure to deliver above the firm energy amount. Bidders may not sell energy below the Split Bid Threshold Level to third parties.	**Small Projects:** *Reduces Transaction Costs* – The requirement to sell the entire output from small projects to BC Hydro reduces the complexity of the EPA and reduces EPA administration costs. **Large Projects:** *Cost-effective* - By allowing split bids for larger projects, the terms of this Call facilitate participation by projects producing energy in excess of that which would be purchased under the terms of this Call. This encourages competition in the CFT process thereby reducing bid prices. Allowing "split bids" will not affect reliability of supply because BC Hydro will have first priority on all energy produced by the projects awarded EPAs under this Call.	Generally, the contracts in the selected jurisdictions that are capacity contracts allow split bids while the energy contracts do not.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
6.	**Interconnection and Metering Issues** **Connection to the System** : Projects in both streams that are located within the area of the integrated BC Hydro/BCTC transmission/distribution system must: (i) be metered separately; (ii) have a direct interconnection to the BCTC or BC Hydro system (and for this purpose a direct interconnection includes a configuration where the generating equipment is connected to a facility such as a pulp mill provided that the electricity from the generating equipment can be injected into the transmission system when the pulp mill is not operating), and (iii) not be located in the Fort Nelson area. Projects that are not located within the area of the integrated BC Hydro/BCTC transmission/distribution system will be eligible, but the point of delivery must be at a specified point on the integrated BC Hydro/ BCTC transmission/distribution system. The project must be metered separately at the generator. Losses between the meter and the point of delivery will be deducted for payment purposes. **Completed Interconnection Study:** BC Hydro requires all bidders to have, at the time of tender submission, a completed preliminary interconnection study. However, further consideration of all aspects of interconnection and transmission issues will be undertaken as part of BC Hydro's review of the recently released decision of the Commission relative to BCTC's new OATT.	**Connection to the System:** *Reduces Project Risk* – BC Hydro will not take the transmission risk prior to delivery into the integrated BC Hydro transmission system as BC Hydro is in no better position than the bidders to manage this risk. *Reduces Transaction Costs* – BC Hydro's transaction costs are reduced by the fact that BC Hydro is not responsible for arranging interconnection or transmission for projects outside BC Hydro/BCTC's integrated area. *Cost-effective* – BC Hydro is not exposed to the transmission rate risk with respect to projects located outside the BC Hydro/BCTC integrated area. **Completed Interconnection Study**: *Reduces Transaction Costs/Complexity/Risk* – Currently, preliminary interconnection results remain valid for several months. By requiring bidders to have completed preliminary interconnection studies prior to submission of a tender, conduct of the studies is distributed over a longer time frame than would be the case if studies were completed after tender submission. This reduces transaction costs in completing the studies and reduces the risk of study delays. Allowing bidders to complete interconnection studies after tender submission could require a process for bidders to resubmit bid prices after receipt of completed interconnection studies. Re-tendering is inconsistent with fair competitive tender practice, and would effectively be the equivalent of deferring final tender submission until interconnection studies are complete. *Reduces Project Risk* – By requiring bidders to have completed preliminary interconnection studies prior to tender submission, BC Hydro and the bidders have an assurance, prior to tender submission, that the project is feasible from an interconnection perspective.	Almost all the procurement processes in the selected jurisdictions require that the seller deliver the power to a specified point of delivery in the buyer's service area. Many of the selected jurisdictions do not require that the bidders have completed interconnection studies prior to proposal submission. In those jurisdictions, interconnection studies are performed after proposals are submitted and have been subject to the first step(s) in the evaluation process.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
7	**Bidder Experience** BC Hydro will assess bidders to ensure that they have, or have access to, sufficient prior experience in developing, financing and operating power projects comparable to that proposed.	*Reduces Project Risk/Increases Reliability of Supply/Cost-effective* - Provides increased assurance that a project for which BC Hydro awards an EPA will be successfully completed and operated in accordance with the EPA. It is in all parties' interest that BC Hydro does not award an EPA to a bidder that has an unacceptable level of project experience rather than relying on post-award contractual remedies if the project fails.	Evaluation of bidder experience is a common practice in the industry, supported by the jurisdictional review. Virtually all the selected jurisdictions review the bidder's (or the bidder's team) project experience.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
8	**Financial Strength** BC Hydro will assess bidders to ensure that they have, or have access to, appropriate financial strength to finance, develop and operate their project successfully.	*Reduces Project Risk/Cost-effective* - Provides increased assurance that a project for which BC Hydro awards an EPA will be successfully completed and operated in accordance with the EPA. It is in all parties' interest that BC Hydro does not award an EPA to a project that has an unacceptable level of financial strength rather than relying on post-award contractual remedies if the project fails.	Evaluation of bidders' financial strength is a common practice in the industry, supported by the jurisdictional review. All of the comparable jurisdictions include an assessment of financial strength or ability to provide credit support in their evaluation process.

No	Requirement	Rationale	Comparison with Selected Jurisdictions
9	**Project Risk Assessment** BC Hydro will assess tendered projects to determine whether the projects pose unacceptable risk with respect to project completion by the guaranteed COD or operation in accordance with the terms of the EPA. The assessment will take into account factors such as site control and tenure, permitting status, GHG mitigation plans, progress toward other project milestones, fuel supply arrangements and availability, and an assessment of the expected useful life of the proposed project.	*Reduces Project Risk/Increases Reliability of Supply/Cost-effective* - Provides increased assurance that a project for which BC Hydro awards an EPA will be successfully completed and operated in accordance with the EPA. It is in all parties' interest that BC Hydro does not award an EPA to a project that has an unacceptable level of project risk rather than relying on post-award contractual remedies if the project fails.	Evaluation of development risk is common practice in the industry, supported by the jurisdictional review. Virtually all of the comparable jurisdictions review the risk that the proposed project can be completed on schedule. Many include an assessment of overall project risk (i.e. not just focused on COD timing).

No	Requirement	Rationale	Comparison with Selected Jurisdictions
10	**Tender Security** **<u>Large Project Stream:</u>** Tender security is $10,000/MW, calculated as the annual firm energy (in MWh) divided by 8760 hours. **<u>Small Project Stream:</u>** Tender security is $5,000/MW based on the project capacity. Assuming projects in this stream have a 50% capacity factor, the tender security for projects in the Small Project stream is approximately the same, on a unit basis, as for the projects in the Large Project stream.	*Reduces Project Risk* - Tender security is intended to secure a bidder's obligation to sign EPA(s), if awarded and to deliver the required performance security. Tender security provides increased assurance of executed EPAs resulting from the CFT process. Tender security is set at a level sufficient to discourage non-serious bidders from participating in the CFT process. *Reduces Transaction Costs* – Tender security reduces transaction costs by ensuring that those who are awarded EPAs will sign them in the form required under the CFT without post-award negotiations.	Most of the procurement processes in the comparable jurisdictions are RFP processes and therefore do not contemplate tender security. However, some jurisdictions have proposal security (e.g. Nova Scotia - $25,000 bid bond; Ontario 2004 RFP - $25,000/MW of contract capacity; Ontario draft 2005 RFP - $10,000/MW of contract capacity).

Tender Evaluation Criteria and Methodology – Key Elements

July 8, 2005

Notes:

- ***This Exhibit has been prepared for filing in a regulatory proceeding. The final CFT and EPA will be the governing legal documents between BC Hydro and Bidders/Successful Bidders and this Exhibit will have no contractual legal effect.***
- ***For a list of the selected jurisdictions and associated power procurement processes, see Exhibit "F" to the Direct Testimony of Mary Hemmingsen.***
- ***The general approaches to evaluation of Small Projects and Large Projects are substantially similar, but there are some differences. Therefore the general approach is presented below separately for each stream.***

No	Key Element	Rationale	Comparison with Selected Jurisdictions
Small Projects			
1	**Small Project Evaluation – General Approach** **<u>Evaluation Phases:</u>** 1. ***Initial assessment:*** • Conformity review • Mandatory requirements • Bidder experience and financial strength • Project risk 2. ***Price levelization:*** • Calculate real levelized bid price • Initial period price constraint 3. ***Determination of adjusted bid prices:***	BC Hydro proposes to adopt an evaluation process that gives appropriate weight to price and non-price factors and that is fully transparent as to price adjustments for evaluation purposes. After initial assessment of tenders and adjusting bid prices, the evaluation process reserves to BC Hydro a discretion to determine the optimal portfolio by applying price and other criteria in order to best serve the interests of BC Hydro and its ratepayers. This approach allows BC Hydro to consider the possible impact of a range of non-price criteria on	None of the selected jurisdictions reviewed had an exclusively quantitative evaluation approach to proposal or tender evaluation. Insofar as quantitative elements, many do not offer the degree of transparency to which BC Hydro is committed. Some jurisdictions use the least cost approach to select winning projects. Other jurisdictions use maximum value as the selection method. However, all selected jurisdictions recognize the need for an evaluation process that gives the buyer sufficient discretion to avoid being compelled to accept a sub-optimal result, which would result if relevant non-price criteria were ignored. The evaluation criteria and methodology proposed by BC Hydro is very consistent with that applied in the selected jurisdictions.

No	Key Element	Rationale	Comparison with Selected Jurisdictions
	• Green credit • Interconnection/transmission adjustment • GHG adjustment 4. ***Determination of Optimal portfolio:*** BC Hydro's evaluation team will determine the optimal portfolio of tenders by applying price and non-price criteria, including, but not necessarily limited to: • low cost, based on adjusted bid price, • portfolio interconnection and transmission costs and other impacts, • target aggregate portfolio of 50 MW, subject to assessment of system needs for greater or lesser energy, • environmental attributes, including the 50% BC Clean Electricity target, and • lower project risk and overall portfolio development risk and operations risk to enhance the timeliness and reliability of supply, including the benefits of regional diversity. ***Notes:*** 1. The evaluation will reflect a strong preference for low cost, based on adjusted bid price, and the 50% BC Clean Electricity target, but the relative weighting of criteria	portfolio value, and to capture the value and benefits of tender and portfolio non-price attributes that may be available at a justifiable incremental cost, if any. Awarded EPAs will be filed with the Commission as "energy supply contracts", with a full, reasoned report on the evaluation process and outcome. As a regulated utility, BC Hydro's determination of the optimal portfolio needs to respect the regulatory imperatives of prudence and respect for the public interest, which could be threatened if this determination was subject to undue prescription. An exclusively quantitative approach, based only on adjusted bid prices, carries the risk that BC Hydro could be compelled to accept a sub-optimal result, which may not meet with regulatory approval, or alternatively terminate the process with no contract awards, in either case with a consequent loss to bidders and ratepayers.	

No	Key Element	Rationale	Comparison with Selected Jurisdictions
	will not otherwise be predetermined. 2. All criteria will be applied with a view to determining the portfolio which bests serves the interests of BC Hydro and its ratepayers, while respecting the regulatory need for prudence and respect for the public interest. 3. The portfolio having the lowest cost, based solely on adjusted bid price, will not necessarily be determined to be optimal or result in contract awards. 4. The portfolio determined by BC Hydro's evaluation team to be optimal will be recommended to BC Hydro senior management for EPA awards. 5. Awarded EPAs will be filed with the Commission as "energy supply contracts", together with a full, reasoned report on the evaluation process and outcome, which will address justification for the way in which non-price criteria have been applied. 6. BC Hydro may, in its discretion, terminate the process as to Small Projects and award no EPAs.		

Large Projects			
2	**Large Project Evaluation – General Approach** **<u>Evaluation Phases:</u>** 1. ***Initial assessment:*** • Conformity review • Mandatory requirements • Bidder experience and financial strength • Project risk 2. ***Price levelization:*** • Calculate real levelized bid price • Initial period price constraint 3. ***Determination of adjusted bid prices:*** • Green credit • Hourly firm adjustment • Interconnection/transmission adjustment, including "cluster effects" • GHG adjustment 4. ***Determination of optimal portfolio:*** BC Hydro's evaluation team will determine the optimal portfolio of tenders by applying price and non-price criteria, including, but not necessarily limited to: • low cost, based on adjusted bid price,	BC Hydro proposes to adopt an evaluation process that gives appropriate weight to price and non-price factors and that is fully transparent as to price adjustments for evaluation purposes. After initial assessment of tenders and adjusting bid prices, the evaluation process reserves to BC Hydro a discretion to determine the optimal portfolio by applying price and other criteria in order to best serve the interests of BC Hydro and its ratepayers. This approach allows BC Hydro to consider the possible impact of a range of non-price criteria on portfolio value, and to capture the value and benefits of tender and portfolio non-price attributes that may be available at a justifiable incremental cost, if any. Awarded EPAs will be filed with the Commission as "energy supply contracts", with a full, reasoned report on the evaluation process and outcome. As a regulated utility, BC Hydro's determination of the optimal	None of the selected jurisdictions had an exclusively quantitative evaluation approach to proposal or tender evaluation. Insofar as quantitative elements, many do not offer the degree of transparency to which BC Hydro is committed. Some jurisdictions use the least cost approach to select winning projects. Other jurisdictions use maximum value as the selection method. However, all selected jurisdictions recognize the need for an evaluation process that gives the buyer sufficient discretion to avoid being compelled to accept a sub-optimal result, which would result if relevant non-price criteria were ignored. The evaluation criteria and methodology proposed by BC Hydro is very consistent with that applied in the selected jurisdictions.

	• portfolio interconnection and transmission costs and other impacts, • target minimum aggregate portfolio of 800 GWh/y firm energy and up to 800 GWh/y non-firm energy, subject to assessment of system needs for greater or lesser energy, • firm energy, including hourly firm, • environmental attributes, including the 50% BC Clean Electricity target, and • lower project risk and overall portfolio development risk and operations risk to enhance the timeliness and reliability of supply, including the benefits of regional diversity. ***Notes:*** 1. The evaluation will reflect a strong preference for low cost, based on adjusted bid price, and the 50% BC Clean Electricity target, but the relative weighting of criteria will not otherwise be predetermined. 2. All criteria will be applied with a view to determining the portfolio which bests serves the interests of BC Hydro and its ratepayers, while respecting the regulatory need for prudence and respect for the public interest. 3. The portfolio having the lowest cost, based solely on adjusted bid price, will not necessarily be determined to be optimal or	portfolio needs to respect the regulatory imperatives of prudence and respect for the public interest, which could be threatened if this determination was subject to undue prescription. An exclusively quantitative approach, based only on adjusted bid prices, carries the risk that BC Hydro could be compelled to accept a sub-optimal result, which may not meet with regulatory approval, or alternatively terminate the process with no contract awards, in either case with a consequent loss to bidders and ratepayers.	

	result in contract awards. 4. The portfolio determined by BC Hydro's evaluation team to be optimal will be recommended to BC Hydro senior management for EPA awards. 5. Awarded EPAs will be filed with the Commission as "energy supply contracts", together with a full, reasoned report on the evaluation process and outcome, which will address justification for the way in which non-price criteria have been applied. 6. BC Hydro may, in its discretion, terminate the process as to Large Projects and award no EPAs.		

Specific Issues:			
3	**Conformity Review** Tenders will be reviewed on receipt for conformity with formal requirements for tender submission, which will be clearly specified in the CFT. BC Hydro will retain the right to waive non-material non-conformities so that inconsequential deficiencies will not preclude consideration of an otherwise qualifying tender.	A conformity review is consistent with good tendering practice and is necessary to ensure that all bidders compete on a level playing field. Also, tender law imposes on BC Hydro an obligation to consider only conforming tenders, except where non-conformities can properly be waived.	Conformity reviews are common in most selected jurisdictions, although non-binding RFP processes may afford somewhat greater flexibility in waiving non-conformities, but arguably at the expense of fairness and equal treatment of bidders.
4	**Mandatory Requirements** Tenders will be assessed to determine if they meet mandatory requirements, which will be limited, largely objective, and specified in the CFT. BC Hydro will have no discretion to waive mandatory requirements. See Exhibit "A" to the Direct Testimony of Mary Hemmingsen for further information on mandatory requirements.	The application of mandatory requirements ensures that all tenders meet BC Hydro's basic product description. As these requirements are fundamental and mandatory, the process does not permit waiver of such requirements.	The application of mandatory requirements is common in selected jurisdictions .
5	**Bidder Experience, Financial Strength and Project Risk** Each tender will be assessed in respect of bidder experience and financial strength, and also to assess project development and operational risk. The CFT will outline information required on tender submission to assist BC Hydro in this assessment process, and BC Hydro will reserve the right to seek	This assessment is intended to ensure that tenders which proceed to further consideration justify a reasonable expectation that they will offer BC Hydro timely and reliable supply.	Most selected jurisdictions consider bidder experience and financial strength and attributes of project risk. These considerations may be dealt with by a pass/fail assessment, or by applying these, among other, criteria to the evaluation.

	further information and clarification to ensure that a fair and informed assessment is completed. The results will be on a "pass/fail" basis. See Exhibit "A" to the Direct Testimony of Mary Hemmingsen for further information on these assessments.		
6	**Levelized Pricing** The CFT will permit bidders to quote an EPA term from 15 to 40 years and also stepped pricing in two portions of that term. The CFT will restrict the differential between the stepped prices. BC Hydro will levelize pricing in all tenders as a first step in adjusting bid prices for comparability.	Levelizing bid prices is necessary to achieve comparability of tenders having different terms and stepped pricing. The limitation on the differential in stepped prices will constrain undue "front end loading".	Levelizing bid prices is an accepted utility practice.
7	**Adjusted Bid Prices** Certain specified quantitative adjustments will be made to levelized bid prices to reflect values of specific tender attributes.	Adjusting levelized bid prices is necessary to represent the delivered cost of a common electrical product to a common delivery point.	Certain specified quantitative adjustments are made to levelized bid prices by some selected jurisdictions to reflect values of specific tender attributes.
8	**Green Credit for Green Attributes** The green credit is applicable to both streams. Projects that can achieve Ecologo^{M} certification can elect to tender Green Attributes to BC Hydro, in which case a credit of $3/MWh will be applied for evaluation purposes.	Shorter term, the credit reflects the marketability of Green Attributes offered by bidders, and the different values for different green power certificated products. For example, the average price on the spot market for green credits for the period November 2004 to April 2005 was approximately $2 to $3 (US)/MWh, depending on technology.	The Canadian federal government is proposing to offer a $10/MWh power production incentive payment for renewable power for a 10-year term (current WPPI program, proposed WPPI program extension and proposed RPPI program). Most of the selected jurisdictions had separate calls for renewable power. Of the selected jurisdictions that had open calls, the Public Service Company of Colorado explicitly applies

			a credit of $8.75 (US)/MWh for all renewable energy bids from eligible renewable energy resources (generally – solar, wind, geothermal and biomass and hydroelectric resources, with a nameplate rating of 10 MW or less). The credit does not escalate.
9	**Interconnection/Transmission Adjustment** This adjustment will apply to both streams. Subject to a full evaluation of the decision of the BCUC on BCTC's new OATT, BC Hydro will take transmission impacts into account by way of a bid price adjustment as part of the evaluation process. Further details will be available following completion of a review of the decision. In the case of Large Projects only, "cluster effects", if any, will also be considered. See Exhibit "A" to the Direct Testimony of Mary Hemmingsen for further information on interconnection and metering.	Recognition of the full cost and impact of interconnecting and transmitting power to the Lower Mainland is essential to a fair assessment of the value of the each tender. The larger project size in the Large Project stream requires that "cluster effects", if any, also be taken into account. For simplicity and recognizing the smaller size of projects in the Small Project stream, "cluster effects" will not be considered.	A number of selected jurisdictions consider the impact of transmission upgrades triggered by proposed projects as part of the evaluation process.
10	**GHG Adjustment** This adjustment will apply to both streams. Bidders may assume all GHG liability, or alternatively, may elect that BC Hydro assume specified GHG liability in respect of offset purchases required by law and regulation, subject to a specified GHG intensity for the relevant project, as specified in the tender.	The GHG option gives bidders flexibility. They may make their own assessment of expected GHG intensity and associated offset liability, and then either (i) accept and price for that risk, or (ii) transfer that exposure to BC Hydro and accept the specified adjustment to be applied for tender evaluation	Public Service Company of Colorado applies a CO_2 cost adder for assuming the GHG risk based on $9 (US) per ton beginning in 2010 and escalating at 2.5% per year beginning in 2011.

	If a bidder elects to transfer GHG offset liability to BC Hydro as indicated above, the bid price will be adjusted by a specified amount, determined from a table to be published in the CFT. A preliminary indicative table follows this Exhibit "B".	purposes. This flexibility is expected to yield the most cost-effective result relative to pricing for GHG offset risk.	
11	**Hourly Firm Adjustment** This adjustment applies only to Large Projects. A bidder may elect the hourly firm option (as opposed to monthly firm), in which case an adjustment of $3/MWh will be applied to recognize the benefit to BC Hydro of that election.	The hourly firm credit provides a evaluation benefit to bidders that can deliver a firmer energy product (i.e. hourly, rather than monthly). The adjustment amount is based on the levelized cost of Revelstoke Unit #5, inclusive of foregone system benefits to BC Hydro.	Among the selected jurisdictions, no specific adjustments were provided for in the evaluation methodology for hourly firm delivery.
12	**Determining the Optimal Portfolio** This step applies to both streams. With a strong preference for low cost, and the BC Clean Electricity target, BC Hydro's evaluation team will determine the optimal portfolio by applying the price and non-price criteria summarized above. The criteria identify preferences that may impact final determination of the optimal portfolio, which are similar, but not identical, for both streams. The aggregate amount of energy to be purchased under each stream is a target. EPAs for somewhat more or less aggregate energy may be awarded depending on	Refer to the discussion above concerning the rationale for applying a range of criteria, with a strong preference for low cost, and the BC Clean Electricity target.	All selected jurisdictions utilized an approach that determined the optimal portfolio by applying price and non-price criteria. Many selected jurisdictions allowed flexibility in the aggregate amount of energy to be purchased.

	tenders submitted, pricing and other attributes and the latest data on energy needs available at the time the evaluation is carried out. The criteria includes the BC Clean target of 50% in aggregate. This is consistent with the BC Energy Plan. Other criteria listed above are self-explanatory.		

PRELIMINARY

GHG Bid Adjuster Look-up Table -
$(2006)/MWh vs. Emission Rate and Full Contract Term

	EPA Term					
	15	20	25	30	35	40
Emissions CO2e t/MWh						
0.1	$0	$0	$0	$0	$0	$0
0.2	$0	$0	$0	$0	$0	$1
0.3	$1	$2	$2	$2	$2	$3
0.4	$2	$2	$3	$3	$3	$3
0.5	$4	$5	$5	$6	$6	$7
0.6	$7	$7	$8	$8	$9	$10
0.7	$9	$10	$10	$11	$12	$13
0.8	$11	$12	$13	$14	$15	$16
0.9	$13	$14	$16	$17	$18	$20
1.0	$15	$17	$18	$20	$21	$23
1.1	$18	$19	$21	$23	$24	$26
1.2	$20	$22	$23	$25	$27	$29

EPA Terms and Conditions

July 8, 2005

Notes:

- ***This Exhibit has been prepared for filing in a regulatory proceeding. The final CFT and EPA will be the governing legal documents between BC Hydro and Bidders/Successful Bidders, and this Exhibit will have no contractual legal effect.***
- ***For a list of the selected jurisdictions and associated power procurement processes see Exhibit "F" to the Direct Testimony of Mary Hemmingsen.***

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
1	**EPA Term** Bidders may select an EPA term of 15, 20, 25, 30, 35 or 40 years.	The proposed provision addresses the risk that a single fixed contract term may not match the capability of the bidder's plant. This may reduce the pool of eligible bidders and/or limit BC Hydro's ability to access lower power prices. Allowing bidders to choose a contract term reduces bidder risk. Allowing longer term contracts may increase BC Hydro's risk associated with the market	*Cost – effective* – Allowing bidders to select from a range of contract terms allows bidders to select the contract term that best matches the characteristics of the project (useful life, fuel supply arrangements, land tenure etc.). Offering a range of contract terms should enable more bidders to participate in the process. Increased competition should result in lower bid prices. Some IPPs have also indicated that they can offer lower prices for longer term	Generally, bidders are given a range of contract terms to select from. Maximum term offered in the procurement processes in the selected jurisdictions is 30 years.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
		price of electricity.	contracts. It is also desirable for BC Hydro to develop a portfolio of IPP contracts with varying terms. BC Hydro may mitigate its risk with respect to the long term contracts by conducting a project risk assessment to determine the capability of the project to perform for the term proposed by the bidder, by the pricing provisions (discussed below) and by developing a portfolio of contracts with differing contract terms.	
2	**Regulatory** The EPA will provide either party with the right to terminate if within 120 days after the EPA is filed with the Commission, the Commission convenes a public hearing with respect to the EPA and either (a) that hearing has not been completed or is completed but no order under section 71(3) of the *Utilities Commission Act*	Under the proposed terms, both parties share the regulatory risk as neither party recovers costs from the other party if regulatory approval is not obtained.	Bidders are in a position to control their costs pending receipt of regulatory approvals, but should not be expected to hold bid prices during a lengthy period of regulatory uncertainty.	Generally, in the selected jurisdictions, where regulatory approval is required, the contract provides a specified period of time for that approval to be obtained after which either or both parties can terminate without liability to the other party. Buyers do not compensate sellers for bid costs or other costs incurred if regulatory

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	(UCA) has been made or (b) an order has been issued which contains terms that could reasonably be expected to have an adverse effect on the party seeking to terminate the EPA. On termination under this provision, all securities are returned to the successful bidder but no termination payments are made by either party.			approval is not obtained.
3	**COD Timing** Bidders can elect a guaranteed COD between October 1, 2008 and October 1, 2009. A bidder may achieve COD up to 12 months in advance of the guaranteed COD but no earlier than January 1, 2008 without the consent of BC Hydro. For projects in the Large Project stream, where COD is delayed more than 180 days after the guaranteed COD (plus force majeure days), liquidated damages (LDs) will be payable.	The early COD provisions are addressing the risk that energy is ready to be delivered in advance of BC Hydro's requirements. Under the proposed provision, this is a shared risk. BC Hydro has provided some flexibility to bidders to achieve COD early, recognizing the difficulty of precise project scheduling but has provided some limitation on early COD. Prior to COD, bidders can sell	The bidder is in a better position than BC Hydro to control the risk of COD timing by prudent contracting (e.g. EPC and other procurement contract terms) and project management. With respect to early COD, some bidders indicated that they would be in a position to implement a more cost-effective project with an earlier in-service date. This is particularly the case for those projects that intend to apply for the federal	Virtually all selected jurisdictions have a concept of a guaranteed COD date often with associated delay LDs and almost always with a right to terminate for a significant delay in COD. Prolonged delay ranges from 30 days to 24 months. Most selected jurisdictions do not restrict early COD.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	These damages are discussed below in the Liquidated Damages section. In both the Large Project and Small Project stream, delayed COD gives rise to a right on the part of BC Hydro to terminate the EPA. This right to terminate arises 365 days after the guaranteed COD as extended by force majeure, not exceeding an additional 365 days. If BC Hydro terminates on this basis (except where the delay was caused by force majeure), the successful bidder is subject to a termination payment equal to the amount of the performance security.	energy to third parties. The late COD provisions are addressing the risk that projects may not be ready when BC Hydro requires the energy. The proposed provisions result in a sharing of both the late COD and COD failure risk. Bidders take the risk with respect to late COD timing, subject to LD caps. Bidders take the risk of COD failure, subject to limitations of liability on the termination payments. To the extent BC Hydro's damages exceed the bidder's liquidated damages or the limitations on the termination payments, BC Hydro is responsible for the COD delay and COD failure risk.	government WPPI incentives. While there is some additional cost to BC Hydro associated with projects that may have an earlier in-service date, that cost is expected to be small and mitigates energy supply and demand uncertainties. These uncertainties include load growth, local issues that affect IPP development, project delays or attrition among existing IPPs and energy savings from DSM initiatives.	
4	**Delivery Obligation** **<u>Large Projects:</u>** For monthly firm contracts, the	The delivery obligation provisions are addressing the risk that the firm energy tendered will not	Successful bidders are in a better position to control plant performance and can assess the expected output of their projects. Successful	In all selected jurisdictions, sellers take the delivery risk. Some contracts limit the seller's risk by imposing a cap on liability for delivery

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	succesful bidder is required to deliver the tendered monthly firm energy amount in each month. All energy delivered in any given month (below any Split Bid Threshold Level) is measured against the tendered firm energy amount for that month. Shortfalls in monthly deliveries will be subject to mark-to-market LDs with a $/MWh cap discussed below. For hourly firm contracts, the successful bidder is required to deliver the tendered hourly firm energy amount in each hour. Shortfalls in hourly energy deliveries will be subject to mark-to-market LDs with a $/MWh cap discussed below. The successful bidder's delivery obligation is excused by: • force majeure (does not include unavailability of fuel), • planned outages that comply with the EPA, • transmission and distribution	be delivered. Under the proposed provisions, BC Hydro and the successful bidder share the delivery risk. Successful bidders have the delivery risk up to the $/MWh cap on delivery shortfall LDs and the annual limits of liability. To the extent that BC Hydro's damages associated with delivery shortfalls exceed the $/MWh cap or the annual limit of liability, BC Hydro absorbs the delivery risk. To the extent that delivery is interrupted by an event that excuses the delivery obligation, the parties share the risk as the successful bidder in some cases (e.g. planned outages, force majeure) does not get paid for energy that is not delivered and BC Hydro does not receive the	bidders in the Large Project stream have the option of bidding lower firm energy amounts in order to mitigate non-delivery risks. Small Projects will not be required to tender a minimum delivery profile on the basis that the administrative burden and cost to monitor energy deliveries against a contracted energy profile is not justified given the size of the projects.	shortfalls. Capacity contracts tend to impose liability for failure to meet an hourly delivery obligation. Energy contracts generally contain a covenant to generate but assess damages for shortfalls on an annual basis. However, some jurisdictions assess damages for monthly shortfalls (e.g. Sierra Pacific). The selected jurisdictions are approximately evenly divided on the question of granting force majeure relief for lack of an intermittent resource.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	issues not caused by successful bidder, and • Successful bidder suspension based on BC Hydro default. **<u>Small Projects:</u>** There is no minimum delivery obligation for projects in the Small Project stream. Successful bidders are required to maximize generation subject to fuel availability, outages etc. There are no LDs for delivery shortfalls.	energy and receives no additional payment from successful bidder to cover damages.		
5	**Purchase Obligation** **<u>Large Projects:</u>** Provided that the bidder has not elected the "split bid" option, BC Hydro will purchase the entire output from a contracted project up to 120% of the maximum project capacity of the successful bidder's plant sized at COD. If	The purchase obligation provisions are addressing the successful bidder's risk that BC Hydro will not accept delivery of energy. The 120% cap on the purchase obligation is addressing the risk that too much energy is delivered from a plant. The purchase obligation is	BC Hydro is in a better position than the successful bidder to control the risk of problems after the point of delivery. Therefore, BC Hydro should generally be required to accept and pay for energy that is delivered to the point of delivery subject to a cap on deliveries based on the capacity of the facility (or in the case of split bids up	The proposed contract terms are consistent with selected jurisdictions. Force majeure generally excuses the buyer from its obligation to accept deliveries of energy. In the case of capacity contracts, the buyer is generally not excused from its payment obligation where the buyer declares or is excused only

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	the bidder elected the "split bid" option, BC Hydro will purchase all energy up to the Split Bid Threshold Level. **<u>Small Projects:</u>** BC Hydro will purchase the entire output of the successful bidder's plant up to a maximum of 120% of the maximum project capacity of the successful bidder plant sized at COD. BC Hydro is excused from its purchase obligation under either the Large Project or the Small Project stream EPA in certain circumstances such as force majeure, transmission issues or disconnection for reasons not attributable to BC Hydro and distribution issues where BC Hydro is authorized to disconnect the successful bidder plant or suspend service. BC Hydro continues to pay in some of these circumstances after the first 24 hours in aggregate in each	addressing the risk that successful bidders may not be able to access the market and thus may not be able to sell their entire generation output The purchase obligation is BC Hydro's risk subject to the specified exceptions (e.g. force majeure). The risk with respect to the specified exceptions is shared in the sense that where BC Hydro cannot accept power, the successful bidder in some cases will not get paid. However, BC Hydro will continue to pay in some circumstances in which BC Hydro is excused from its purchase obligation (after the first 24 hours in aggregate in each month).	to the Split Bid Threshold Level) and subject to events that are beyond the control of BC Hydro. BC Hydro is in a better position to access the market and to better manage the excess energy.	for a specified period. In the case of energy contracts, the buyer generally does not pay during a force majeure event declared by the buyer.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	month of occurrence of the specified event.			
6	**Firm Energy Price (Large Projects) and Energy Price (Small Projects)** The pricing structure for firm energy is a fixed $/MWh price tendered by the bidder rather than a price tied to a market index. After COD, payment to successful bidder will be based on their bid prices adjusted to reflect BC Hydro's intra-day preferences (i.e. prices will be subject to premiums and discounts for deliveries in heavy load hours ("HLH") and light load hours ("LLH"). Further, price premiums and discounts will also be applied based on the month of delivery, with larger premiums applied to higher demand months and larger discounts applied to lower demand months. For any term longer than 15	The first risk the pricing provision addresses is the risk that BC Hydro sells electricity to its customers based on a fixed rate schedule but the electricity price purchased from successful bidder is based on market prices. The second risk the pricing provisions address is the risk that successful bidder would have more uncertain revenue streams if prices were tied to market indices which may increase the difficulty of obtaining equity and debt financing. The third risk the pricing structure addresses is the risk that BC Hydro receives energy in periods of low value to BC Hydro, to the extent that the successful bidder can	From BC Hydro's perspective, it is appropriate to purchase energy at a fixed prices because such pricing is better matched to BC Hydro's fixed rate schedule and limiting the need for future rate increases arising from long term contracted supply to meet long term load requirements. From the successful bidder's perspective, the proposed pricing provision addresses the risk that successful bidders would have more uncertain revenue streams if prices were tied to market indices, which would increase the difficulty of obtaining equity and debt financing, resulting in lower prices to BC Hydro.The HLH/LLH pricing structure allows bidders to reflect their energy profile in their bid price and encourages	Allocation of this risk is consistent with all selected jurisdictions in the sense that the buyer generally takes the market price risk. However, the pricing structure varies considerably between the jurisdictions.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	years, the bidder will have the option to bid a lower price for the period after 15 years (or such longer initial pricing period as selected by the bidder).	control the timing of those volumes. The fourth risk the pricing structure addresses is the risk that, without pricing flexibility, BC Hydro may not receive the value of long term contracts where the EPA term exceeds the debt term.	delivery of energy in periods of highest value to BC Hydro. The option to bid a lower price for periods after 15 years allows bidders to structure their pricing in a more flexible manner thereby resulting in lower bid prices.	
7	**Price – Escalation – All Streams** Bidder tenders a percentage of the bid price (between 0 and 50%) that escalates with CPI.	The escalation provisions are designed to address the risk that the revenue stream (to the extent impacted by the price paid) for the energy does not match the bidder's cost stream.	The escalation provisions allow bidders to address the risk and uncertainty that their revenue stream does not match their cost stream in a way that limits the exposure for ratepayers Bidders are in a better position than BC Hydro to manage the cost of production and to estimate their future costs. CPI is a generally accepted and transparent inflation index. Having a single inflation	There is no consistent approach to treatment of escalation in the selected jurisdictions. Some allow bidders to propose any type of index or escalation factor. Others limit bidders to choosing from a list of admissible indices. Others limit the escalation to a fixed escalation factor.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
			index reduces bid evaluation and contract administration complexity and cost. BC Hydro anticipates that for most projects the majority of the project costs will be capital costs and associated financing costs. Therefore, restricting escalation to a maximum of 50% of the costs should not impose undue risk on the Bidders.	
8	**Property Tax Rate Adjustment and other Costs** Payments to the successful bidder will be adjusted to reflect the impact of 50% of property tax rate changes from the applicable rate prevailing on the tender submission date for a like project and location. No other "flow through" adjustments (including changes to assessed value of the project) or reimbursements will apply, whether for fuel (including water rentals), other	Regarding property taxes, the bidder takes the risk of assessed value, and the risk of tax rate changes is shared equally between BC Hydro and the bidder. The bidder assumes other development and operating cost risks over the term selected by the bidder, subject to permitted escalation outlined above.	A bidder is in a better position than BC Hydro and its ratepayers to estimate and manage or influence the bidder's overall cost structure. Regarding property tax, assessed value is driven by the project siting and improvements, which are controlled by the bidder, and the bidder is entitled to appeal assessments. Property tax rate changes can be justified as a shared	The only selected jurisdiction that allows any form of flow-through is Public Service Company of Colorado where the buyer assumes carbon dioxide taxes and carbon dioxide allowances, credits, and offset requirement costs (subject to an evaluation adjustment). None of the other jurisdictions allow flow-throughs.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	taxes or costs.		risk, over which BC Hydro and the bidder have limited control and can benefit from a shared interest.	
9	**Non-Firm Energy Price – Large Projects Only** In the Large Project stream, non-firm energy will be subject to stepped discounts as volume increases. There will be two tiers used for the stepped discounts, based on the volume of non-firm energy delivered. **<u>Tier 1:</u>** • Non-firm energy volume in excess of firm energy delivered up to the equivalent of 100% of firm energy volume. • Price based on applicable firm energy price less a $/MWh discount (escalated at CPI and seasonally adjusted based on the	The non-firm pricing provisions address the risk that absent such provisions BC Hydro would pay the same price for a product of lesser value. Under the proposed pricing provisions, BC Hydro assumes the market price risk for Tier 1 non-firm energy . The successful bidder assumes the market price risk for Tier 2 non-firm energy.	While BC Hydro is seeking to acquire firm energy, it recognizes that some projects will have associated non-firm energy. BC Hydro is prepared to accept and pay for that non-firm energy in order to ensure a sufficient number of projects can compete in the CFT. In allowing for non-firm energy, BC Hydro acknowledges that an appropriate amount of non-firm energy can be a cost effective supplement to firm energy. Offering a fixed pricing structure for the first tier of non-firm pricing provides bidders with a higher level of revenue certainty so that they can bid in a cost-	A number of the selected jurisdictions have some form of price discount for excess energy.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	HLH/LLH table). • The discount will be the same for all successful bidders and the amount to be applied is expected to range from $8/MWh to $12/MWh. **<u>Tier 2:</u>** • Volume in excess of Tier 1. • Price is lesser of 70% of average LLH Mid C (less transmission charges to the border) or the applicable LLH Tier 1 price.		effective firm energy price. The $/MWh discount is based on the levelized cost of Mica Unit #5, inclusive of forgone system benefits to BC Hydro. The eventual $/MWh discount to be applied will be determined based on further evaluations for the levilized cost of Mica Unit #5. The pricing in the last tier will be linked to market prices due to the higher uncertainty of the deliveries in that tier of energy. The cap (Tier 1 price) limits BC Hydro's exposure to the market prices recognizing that there are circumstances where market prices may be high while BC Hydro cannot physically access that market.	
10	**Change in Law** There is no price change, cost reimbursement, or termination	The bidder assumes the risk of a change of law, with the specific	With limited exceptions, a bidder is in a better position than BC Hydro to manage the bidder's overall cost	None of the standard form EPAs in the selected jurisdictions provides any change in law relief for

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	or renegotiation right arising from a change in law (except for a flow through for a change in the applicable rate of property taxation as outlined above and relief from the delivery obligation and termination for force majeure).	exceptions noted.	structure. A bidder is likely to be in a better position than BC Hydro or its ratepayers to influence changes in law that have a specific effect on the bidder's cost structure. BC Hydro has adopted a position that is consistent with the position in the comparable jurisdictions reviewed by BC Hydro. Adding change in law provisions would add to the complexity of the EPA and would increase contract administration costs.	sellers, except to the extent the change in law prevents performance (force majeure). The only selected jurisdiction that provides some change in law relief is Public Service Company of Colorado where the buyer assumes some of the GHG regulatory risk.
11	**Liquidated Damages – Large Projects Only** **<u>COD Delay LDs:</u>** Applicable only after 180 days after guaranteed COD (plus force majeure days). Daily amount is 1/180 of the performance security amount	The liquidated damages provisions result in a shared risk –successful bidder assumes the risk on the number of days of COD delay, the volume of energy shortfalls and the market price risk to the $/MWh cap. BC Hydro assumes the risk that its	The bidder is in the best position to manage the risk of COD delays and fluctuations in output from the plant. It is appropriate to measure BC Hydro's loss against a market price as BC Hydro will purchase shortfalls from	Most selected jurisdictions have LDs for late COD. LDs range from $200(US)/MW/day capped at $75,000(US)/MW to $165(Canadian)/MW/day capped at $2,070,000 (Canadian) (but note that it is not possible to determine the LDs under some of the

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	payable for an additional 180 days. Thereafter, no further delay LDs are payable. However, BC Hydro may elect to terminate the EPA. **<u>Shortfall LDs:</u>** *Monthly firm* – Mark to market LDs based on a comparison of the adjusted bid price to the average monthly Mid-C price (capped at $100/MWh, escalating at CPI) plus transmission charges from Mid-C to the border. (Note that for the monthly firm contract, all energy delivered during the month is included in calculating whether or not there is a shortfall in the deliveries for the month. Therefore, a plant that is not generating for several days may not be subject to LDs if the plant can make up the output in other days during the month). *Hourly firm* – Mark to market LDs based on a comparison of the adjusted bid price to the	damages arising from a delivery shortfall exceed the EPA price plus the $/MWh cap.	the market or divert power from its other resources that would otherwise have been available for sale into the market. By capping the LD amount BC Hydro is limiting the liability for projects thereby reducing bid prices. The cap was determined based on a review of Mid-C prices for a number of years. BC Hydro believes that a $100/MWh cap represents a reasonable sharing of risk between successful bidders and BC Hydro.	*pro forma* contracts as the LDs are tied to the bid price or are left as one of the terms to be proposed by the bidders). Most selected jurisdictions provide for liquidated damages in the case of delivery shortfalls. Many jurisdictions provide for mark to market LDs with no cap on liability.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	Mid-C price for the hour in which the shortfall occurs (capped at $100/MWh, escalating at CPI) plus transmission charges from Mid-C to the border.			
12	**Performance Security** **<u>Large Projects:</u>** Letter of credit in the amount of $60,000/MW of project capacity. (In the case of a project that elected to retain some output for sale to third parties, the security will be determined based on the MW equivalent of the Split Bid Threshold Level). Reduced on the first anniversary of COD to $40,000/MW based on the annual tendered firm energy amount (in MWh) divided by 8760 hours. **<u>Small Projects:</u>** Letter of credit in the amount of $30,000/MW of project	The security provisions address the risk that the successful bidder will not pay applicable liquidated damages, other damages or termination payments. The security also ensures that BC Hydro will recover costs associated with transmission upgrades for projects that are not successfully completed.	The security provisions ensure that successful bidders are capable of backing their delivery obligations and address the risk that the successful bidder may not pay the applicable LDs, other damages or termination payments. Security amount for the Large Project stream EPA is based on an estimate of the cost of securing replacement power for a period of six months and an estimate of the average cost of completing network upgrades across all large projects. There will be no separate security required for	The security requirements are consistent with contracts in the selected jurisdictions. Security amount ranges from a high of $125,000(US)/MW to a low of $20,000(Canadian)/MW for post-COD operating security. A number of jurisdictions accept corporate guarantees as an acceptable form of security for all or part of the security requirements.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	capacity. Released on first anniversary of COD. In either stream, the successful bidder will be required to replenish the security if BC Hydro draws on the security.		network upgrades. Security amount for the small project stream EPA is set at a lower amount prior to COD and returned following the first anniversary of COD reflecting the relative size of these projects and the fact that there are no LDs for delivery shortfalls. BC Hydro believes that the security is set at an appropriate level to reflect the risk to BC Hydro and its ratepayers without burdening successful bidders with significant carrying costs. BC Hydro does not accept corporate guarantees as security because they are not a liquid form of security and often require legal proceedings to enforce payment. They also increase contract administration costs as it is necessary to monitor the creditworthiness of the	

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
			guarantor on a regular basis. In addition, corporate guarantees increase BC Hydro's risk. If the guarantor's credit rating begins to fall, it may be difficult to obtain replacement security such as a letter of credit at that point.	
13	**Termination** **<u>Large Projects:</u>** Successful bidder is entitled to terminate for: • Inability to secure material permits by 18 months prior to guaranteed COD on payment of a termination fee of $20,000/MW based on annual tendered firm energy amount (in MWh) divided by 8760 hours. • Other standard termination rights. Except in the case of force majeure declared by BC Hydro (where successful	Termination rights address the risk that the EPA is not being complied with. Termination rights seek to respect the right of a non-defaulting party to terminate its obligations under a contract that is not being performed, while allowing the defaulting party sufficient time to correct problems such that the defaulting party is not at undue risk of premature termination.	The proposed termination rights provide reasonable recognition of BC Hydro's need for reliability of supply without placing undue risk on the successful bidder or its lenders. The successful bidder's right to terminate for inability to secure material permits for a termination fee recognizes that not all projects will have secured all material permits at the time of EPA award. BC Hydro elected not to require Bidders to have all material permits prior to tender submission in order to ensure a robust competition. The termination right	The following discussion focuses on the provision which permits the seller to terminate for failure to get material permits by a specified date on payment of a certain amount as all other termination events are fairly standard. Under EPAs in selected jurisdictions, sellers are not permitted to terminate after the EPA is signed based on an inability to secure permits. Most EPAs include permits as a milestone giving rise to a right for the buyer to terminate the contract if the milestone is missed. Missed milestones in many

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	bidder has an option to terminate or not), BC Hydro pays a termination fee equal to the positive difference if any between the successful bidder's losses and the successful bidder's gains arising from termination. Successful bidder's losses and gains are determined by comparing the EPA firm energy price for the term to the market price for an equivalent amount of power with both amounts being discounted to a present value amount. Where successful bidder terminates pre-COD, BC Hydro's termination payment capped at 115% of the development costs incurred by the successful bidder to that date. BC Hydro has a right to terminate where: • Successful bidder has not obtained material permits by 12 months prior to		provides successful bidders with some flexibility to terminate if permits cannot be obtained while at the same time ensuring that the termination right comes at a price such that only bidders that have sufficient confidence that their projects will be permitted will participate in the CFT process. The termination rights for projects in the Small Project stream reflect the nature and size of the projects.	of the contracts also give rise to delay LDs. However, many EPAs are unclear on the question of whether an inability to get permits would be a force majeure. Most EPAs are silent on this issue and the definitions are such that inability to get permits could be a force majeure thus overriding termination and damages provisions. Some EPAs expressly state that inability to get permits will not be a force majeure. Generally, other termination rights are consistent with applicable termination rights in selected jurisdictions.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	guaranteed COD, • COD has been delayed by more than 365 days, or • other standard termination events have occurred (e.g. successful bidder's insolvency). When BC Hydro terminates the EPA for reasons other than an extended force majeure, the successful bidder is required to pay a termination payment to BC Hydro in an amount equal to the required amount of the performance security. **<u>Small Projects:</u>** Termination rights for the small project stream EPA are similar, except that the successful bidder has right to terminate for any reason at any time in the first year following EPA signing on payment of a termination payment in an amount equal to $10,000/MW of project capacity, and BC Hydro has the right to terminate where there			

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	has been no output from the successful bidder's plant for 180 days, unless excused under the EPA.			
14	**Limit of Liability** **<u>Small Projects:</u>** There is an overall annual limit of liability, subject to exceptions for deliberate breach, equal to $30,000/MW of project capacity. **<u>Large Projects:</u>** Overall annual cap on liability for all liquidated damages and other breaches of the EPA, except deliberate breaches, is equal to 200% of the Performance Security amount.	The risk is that absent the limit on liability, successful bidders are exposed to undue risk, thereby making financing difficult to obtain, which reduces the number of bidders who will participate in the CFT process. The limit of liability results in a sharing of risk. The successful bidder assumes the risk of EPA breaches to the limit of liability. Thereafter, BC Hydro has assumed the risk of the successful bidder's EPA breaches.	BC Hydro believes it is appropriate to offer an overall annual limit of liability to ensure that there is sufficient competition in the CFT.	The selected jurisdictions are mixed. Some jurisdictions provide an overall limit on liability. Others do not.
15	**GHG Requirements** BC Hydro will offer a tender option for bidders to (a) assume responsibility for any and all future GHG regulatory	The risk is that future GHG requirements cannot be quantified with certainty at this time. Permitting agencies will be	The bidder is in the best position to assess whether BC Hydro or the bidder can more effectively manage the GHG offset requirement risk based on the evaluation	With one exception, the EPAs in the selected jurisdictions place the risk of regulatory compliance on the seller. In the Public Service Company of

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	and legal requirements and bidding in a contract price that internalizes GHG risk into their bid prices or (b) have BC Hydro assume responsibility for one type of future GHG regulatory risk (the regulatory requirement to purchase offsets), with the understanding that BC Hydro would apply an evaluation adjuster to the bid price based on the tendered GHG intensity of the projects. This adjustment is discussed in Exhibit "B" to the Direct Testimony of Mary Hemmingsen. All bidders will be required to provide any GHG mitigation plans (as may be required by permitting authorities) as part of the project risk assessment process. For all bidders, the EPA will require the successful bidder to provide regular reports on the successful bidder's GHG compliance.	responsible for assessing GHG risk as it relates to establishing requirements for facilities. The proposed provisions allow the bidder to elect to have BC Hydro assume a portion of this risk. If BC Hydro assumes a portion of the risk, the bidder will remain responsible for offsets required to the extent actual GHG emissions exceed the guaranteed GHG intensity. BC Hydro will assume the risk of the volume of offsets required by regulation (to a maximum of the guaranteed GHG intensity) and the price of those offsets.	adjustments proposed by BC Hydro. The bidder is in the best position to estimate the GHG intensity of its project and to control the factors that affect the GHG emissions and the GHG intensity of the project and should therefore retain the risk of additional requirements that may arise as a result of the GHG intensity of the bidder's plant being different than was represented during the Tender evaluation process. The requirement for bidders to provide any GHG mitigation and offset plan (as may be required by permitting authorities) as part of the project risk assessment process will enable BC Hydro to evaluate the capability of the bidder to effectively manage the GHG risk. This is one factor BC Hydro will take into account in conducting the project risk	Colorado process, the buyer assumes the carbon dioxide tax risk and offset risk. A cost adder will be added to bid prices based on $9 (US) per ton beginning in 2010 and escalating at 2.5% /year beginning in 2011.

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	Failure of a successful bidder to comply with its obligations under the EPA will constitute a default, which gives rise to normal contractual remedies for BC Hydro, subject to reasonable cure periods, including, in the case of a successful bidder's failure to provide offsets under applicable laws and regulations, BC Hydro's right on due notice to perform that obligation and recover the cost incurred from the successful bidder. All EPAs awarded under the terms of this Call will require the successful bidder to comply with all Canadian federal, provincial and municipal regulatory regimes for GHG emissions regardless of whether or not the regimes are otherwise applicable to the projects, based on the timing of COD or any other date stipulated in the regulations. Currently, it is anticipated that the federal requirements will be		assessment. The EPA will provide BC Hydro with the tools to monitor the successful bidder GHG compliance, remedy defaults at the successful bidder's cost and terminate contracts where GHG compliance is not adequate. The suspension and termination provisions will ensure that bidders and their lenders understand the importance BC Hydro places on this issue and should encourage bidders and their lenders to price the GHG risk appropriately.	

No	Term	Risk Allocation	Rationale	Comparison with Selected Jurisdictions
	tied to “Best Available Technology Economically Available” (currently anticipated to be set at 85% to 100% of the GHG emissions of a combined cycle generation turbine facility) standard.			

ALCAN PRIMARY METAL GROUP

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December 22, 2004

Myra E. M. Watson, Corporate Secretary
British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, BC

Re: Long Term Electricity Purchase Agreement dated 27 February, 1990 ("LTEPA")
Notice of Recall of Electricity by Alcan Inc. ("Alcan")

Dear Myra:

Pursuant to paragraph 5.4.2 of the LTEPA, Alcan hereby gives notice that Alcan is recalling from sale to BC Hydro all of the electricity to be made available to BC Hydro pursuant to the LTEPA. The amount of electricity subject to recall under this Notice of Recall is all of the electricity (140 annual average MW, at a load factor of 95%). The recall of electricity will commence and be effective on 1 January 2010 and, as a result, all deliveries of electricity under the LTEPA will terminate as of midnight 31 December 2009.

We confirm the agreement between Alcan and BC Hydro that, in view of the intervening holidays between the date of this letter and 1 January 2005, Alcan may deliver this recall notice before 1 January 2005, and this recall notice will be deemed to be given and delivered to BC Hydro on 1 January 2005. Finally, the address in paragraph 16.4 of the LTEPA for delivery of notices to BC Hydro appears to be out of date. Please confirm that the address for BC Hydro described above is the proper address for delivering this Notice of Recall.

Yours truly,

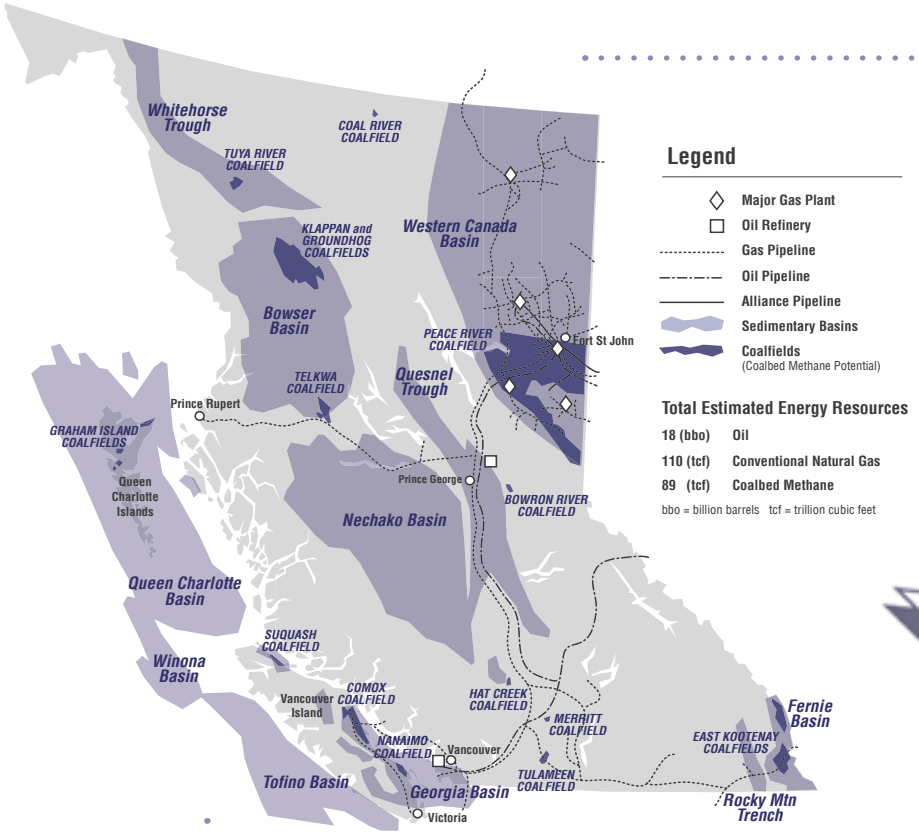
Cynthia Carroll
President and CEO
Alcan Primary Metal Grouop

EXHIBIT E
TO TESTIMONY OF MARY HEMMINGSEN

ENERGY FOR OUR FUTURE: A PLAN FOR BC

EXHIBIT E
TO TESTIMONY OF MARY HEMMINGSEN

BRITISH COLUMBIA'S ENERGY RESOURCES



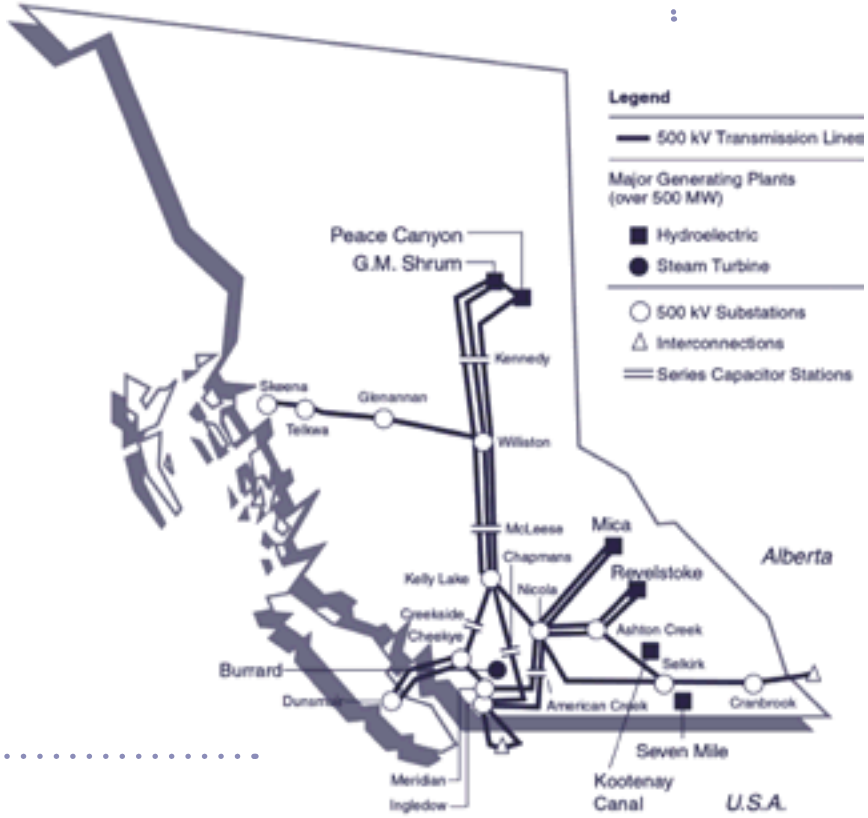
Legend

- Major Gas Plant
- Oil Refinery
- Gas Pipeline
- Oil Pipeline
- Alliance Pipeline
- Sedimentary Basins
- Coalfields (Coalbed Methane Potential)

Total Estimated Energy Resources

18 (bbo)	Oil
110 (tcf)	Conventional Natural Gas
89 (tcf)	Coalbed Methane

bbo = billion barrels tcf = trillion cubic feet



ENERGY FOR OUR FUTURE: A PLAN FOR BC

Low electricity rates and public ownership of BC Hydro

Secure, reliable supply

More private sector opportunities

Environmental responsibility and no nuclear power sources

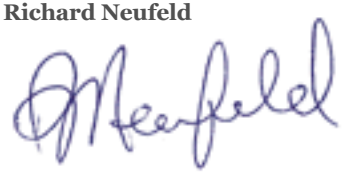
MESSAGE FROM THE MINISTER

Energy is a critical part of our daily lives, powering our households, communities and businesses. In B.C., we have abundant, diverse energy resources, including hydroelectricity, oil, gas, coal, coalbed methane and a variety of clean, alternative sources. The time has come to harness their enormous potential to meet our energy needs and generate renewed economic growth and prosperity for all British Columbians.

Energy for Our Future: A Plan for BC is designed to achieve our goal in an environmentally responsible way. It is built around four cornerstones to maximize benefits for British Columbians well into the future. The cornerstones deliver low electricity prices and public ownership of BC Hydro; a secure, reliable supply of energy; more private sector opportunities; and environmental responsibility with a guarantee of no nuclear generation in B.C.

Ultimately, the plan reflects our government's vision of the future for both the energy sector and the province as a whole -- a prosperous future, lively with opportunities for all British Columbians; a dynamic future, in which British Columbia is opened up to its full potential; a certain future, in which British Columbians can move forward with confidence, knowing they live and work in the best place on earth.

Richard Neufeld



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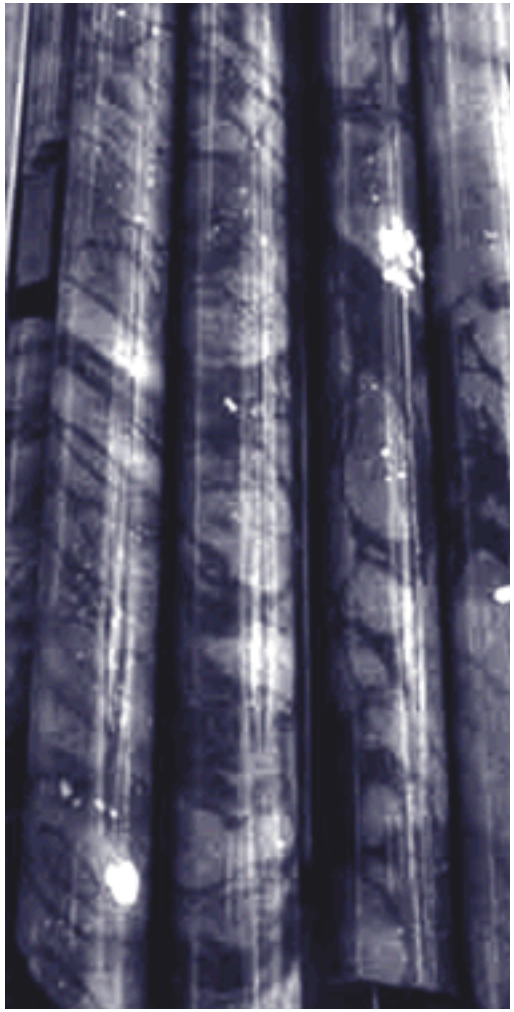
EXECUTIVE SUMMARY



ENERGY FACT

An average household in BC Hydro's service area uses about 10,000 kWh of electricity per year.

After five decades of dramatic change, British Columbia's energy sector faces new challenges and opportunities.

Our natural gas industry has seen production more than double in the past 10 years. In North America and abroad, electric power markets are being reformed to make them more competitive. With these and other changes, the B.C. energy sector is poised for new investment, increased trade and regional economic growth. To realize its potential, the sector needs an updated plan that will guide its further development over the coming decade.

The purpose of this energy policy, *Energy for Our Future: A Plan for BC,* is to build on B.C.'s strengths to help revitalize the provincial economy and create jobs in an environmentally responsible way.

Energy policy and economic policy are inextricably linked. The Government of British Columbia is committed to restoring a strong and vibrant economy with job creation in all regions of the province. At the same time, a healthy environment is recognized as one of our enduring natural assets. This plan builds on B.C.'s advantages, in particular our abundant energy resources and low electricity prices, with improvements to strengthen the energy sector and provide sustainable economic benefits.

BACKGROUND

Energy drives the economy and makes our modern lifestyle possible.

British Columbians depend on energy to fuel their cars, run their appliances, equipment and industrial plants, and light and heat their homes, communities and businesses. Without a reliable and reasonably priced supply of energy, important industries such as forestry, chemicals, mining and high technology cannot thrive in world markets. The production and delivery of energy is itself a source of economic activity, employing about 35,000 people in 2001, and generating about $2.4 billion in provincial revenues that support health care and other programs. While energy production is focused in the Northeast, Southeast, and on the Columbia River, development opportunities offer the prospect of new investment and jobs throughout the province.

B.C. is becoming increasingly integrated with North American energy markets.

Historically, a strong export orientation has allowed B.C. energy suppliers to take advantage of economies of scale to develop energy resources at lower cost, for the benefit of domestic consumers. Today, B.C. exports two-thirds of the energy it produces, including virtually all of our coal and more than half of our natural gas production. Most of the refined petroleum products (e.g., gasoline and home heating oil) we use comes from Alberta, while imported electricity helps meet provincial needs during periods of below-average water inflows into our hydroelectric reservoirs. The net revenues from energy trade contribute to further energy investment and low electricity rates in the province. Energy exports also play a role in continental energy security by providing clean, reliable energy for consumers in the United States and Alberta.

The province enjoys a number of key energy strengths.

B.C. has extensive reserves of coal, oil, natural gas as well as considerable undeveloped resources of coalbed methane (the gas found in coal seams), hydroelectric and alternative energy, such as small hydro, wood residue, ethanol/biofuels, wind and tidal power. In addition, BC Hydro estimates that in the order of 10 percent of electricity demand could be economically saved by 2015, through greater conservation and efficient energy use. B.C. already benefits from a highly developed energy supply network, with substantial production of coal, natural gas, oil and hydroelectricity. Electricity rates among the lowest in North America are the legacy of large-scale public investment on the Peace and Columbia rivers that was undertaken a generation ago.

CHALLENGES AND OPPORTUNITIES

New energy supplies are required to meet growing demand and support renewed economic growth.

More energy is needed to fuel the growth that will restore B.C. to its position as an economic leader within Canada. Rising energy demands and aging facilities call for major financial investment in plant upgrades and new energy production and delivery facilities. This, in turn, requires better access to energy

resources and the timely, cost-effective development of new supplies. Unless domestic energy sources are developed, British Columbians could find themselves increasingly dependent on imports and vulnerable to price swings. The government, faced with competing fiscal priorities, is looking to the private sector for much-needed energy development.

We have to keep electricity rates down to maintain B.C.'s economic advantage.

BC Hydro rates, frozen since 1996, have not changed or undergone a public review since 1993. With electricity costs rising, the rate freeze must end and BC Hydro rates must be independently regulated by the BC Utilities Commission to keep rate changes to a minimum and remove political interference. At the same time, B.C. will need to adapt to evolving market rules in the United States, if we want to continue earning the export revenues that contribute to our low power rates. These rates give B.C. industry an economic advantage in global markets.

Energy development and use must continue to be environmentally responsible.

A clean, natural environment and energy-efficient facilities and equipment are also important to ensuring our long-term economic advantage. British Columbians are concerned about the environmental impacts from energy development and use. Energy-saving activity that reduces demand and defers the need for new supply is one of the most cost effective strategies for controlling impacts on provincial airsheds and watersheds. Low electricity rates, however, provide a poor price signal for consumers to conserve and invest in energy efficiency. In general, unclear environmental standards and inefficient regulatory processes have hindered environmentally responsible energy development in the province.

The energy sector is well positioned to generate new investment, increased trade and economic growth.

B.C.'s natural resources, talent and homegrown technology offer many diverse opportunities for meeting the changing energy needs of provincial consumers. Efforts are underway to make domestic electricity service even more reliable in support of technology industries and the new information economy. The outlook for increased energy trade is favourable, given growing US demands, especially for natural gas in power generation. Here at home, the private sector has demonstrated its ability to develop the smaller-scale generation (e.g., small hydro and efficient natural gas turbines) that can locate close to load, avoid transmission losses and infrastructure costs, and provide regional economic benefits. To enable investment in the oil and gas sector, land use and pre-tenure planning, road upgrading and cooperation with First Nations are improving access to resources for exploration and development in the Northeast.

Low cost hydroelectricity and efficient regulation can help preserve our electricity rate advantage.

While other jurisdictions struggle under large power debts and high electricity prices, B.C. benefits from W.A.C. Bennett's vision of the hydroelectric system developed in the 1960s and 1970s on the Peace and Columbia rivers. These heritage assets have an inherent value given by the difference between their current cost of production and what it would cost to replace this power in the marketplace. There are ways to secure the benefits of existing low-cost generation for B.C. consumers. Furthermore, performance-based regulation and negotiated settlements can be used to regulate BC Hydro rates efficiently and encourage cost savings, so that future rate changes will be minimized.

Aggressive energy saving and alternative energy development can better manage environmental impacts.

For more than a decade, the province's energy utilities, private energy service companies and individual consumers have accumulated expertise in reducing energy use through conservation and energy efficiency. It is possible to design electricity rates to give consumers the right signals for this energy saving activity. We can also develop our alternative energy resources to provide power that is less harmful to the environment than conventional (large hydro, coal-fired and natural gas-fired) generation. Other countries have adopted portfolio standards requiring a portion of electricity supply to come from technologies that have a low impact on the environment.

The energy sector is well positioned to generate new investment, increased trade and economic growth.

Low electricity rates and public ownership of BC Hydro

Secure, reliable supply

More private sector opportunities

Environmental responsibility and no nuclear power sources

SOLUTIONS

The four cornerstones of *Energy for Our Future: A Plan for BC* are low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility and no nuclear power sources.

B.C.'s low-cost electricity will remain an important economic advantage during the next decade. Stable and dependable energy supplies will be vital not only to sustain our other resource industries, but also to grow the technology sector. Private developers, including independent power producers, will be key partners in the province's energy future. We will build on one of North America's best environmental records with efficient regulation that holds energy producers and consumers accountable for their impacts.

Low electricity rates will be assured by entrenching the benefits of publicly owned assets, independently regulating BC Hydro rates and outsourcing services where economic.

BC Hydro ratepayers will benefit from a legislated heritage contract that locks in the value of existing low-cost generation (heritage energy), and from the continued use of trading revenues to supplement domestic revenues. The BC Utilities Commission will conduct an inquiry and recommend the terms and conditions of the heritage contract legislation. To benefit ratepayers and taxpayers alike, public ownership of BC Hydro generation, transmission and distibution assets will continue. The delivery of services will be outsourced where costs can be reduced for consumers while maintaining quality of service. The rate freeze will end on March 31, 2003 and the BC Utilities Commission will hold a revenue requirement hearing by the end of 2003/04 to review BC Hydro costs. Future rate changes will then be determined using performance-based regulation and negotiated settlements.

To promote secure and dependable energy, reliability standards will be maintained, new supplies will be developed and the BC Utilities Commission will be strengthened.

BC Hydro will continue to establish separate lines of business for generation, transmission and distribution. Distribution will acquire new power on a least-cost basis, subject to regulatory

Actions that support low electricity rates and public ownership of BC Hydro:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#2	BC Hydro ratepayers will continue to benefit from electricity trade.
#3	Public ownership of BC Hydro generation, transmission and distribution assets will continue.
#4	BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.
#5	The BC Utilities Commission will once again regulate BC Hydro rates.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#16	The BC Utilities Commission will determine the terms and rates for this new transmission entity.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

oversight. As part of this process, it will obtain heritage energy from the generation business at a rate to be determined by the BC Utilities Commission. The commission's structure and mandate will be strengthened to support the re-regulation of BC Hydro and the efficient regulation of other utilities.

To encourage new resources, the government will develop requirements for exploring and developing coalbed methane and other unconventional hydrocarbon resources. In general, energy reliability will be maintained and improved through well-functioning natural gas markets and coordinated electricity planning.

A dedicated provincial offshore oil and gas team will develop a provincial position, work with the federal government and move effectively toward development of offshore oil and gas resources.

Before offshore development can proceed, further issues need to be resolved such as an agreement between the federal and provincial governments on an overall management regime, including regulatory, royalty and environmental requirements. The Province will also need to work with coastal communities and First Nations to ensure that benefits accrue to the areas where activity occurs.

A dedicated provincial offshore oil and gas team will develop a provincial position, work with the federal government and move effectively toward development of the offshore oil and gas resources.

Actions that support secure reliable supply:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#6	The Vancouver Island Generation Project will be reviewed to determine if it is the most cost-effective means to reliably meet Island power needs.
#7	High reliability and energy security will be maintained through well-functioning natural gas markets and coordinated electricity planning.
#8	BC Hydro distribution will operate as a separate line of business from generation.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#10	Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.
#11	The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to develop a provincial position, work with the federal government and move effectively toward development of the offshore resources.
#12	The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

ENERGY FACT

Industry invested $5.1 billion in B.C.'s petroleum and natural gas resources, a 46 % increase over 2000.

To increase opportunities for the private sector, independent power will be developed and ongoing support will be provided for the oil and gas industry.

Independent power producers (IPPs) will develop new generation, with BC Hydro's role limited to undertaking efficiency improvements at existing facilities. A separate entity, BC Hydro Transmission Corporation, will operate BC Hydro's publicly owned transmission system, to ensure fair access for all generators. Under a new BC Hydro rate structure, IPPs will be able to serve a portion or all of the electricity needs of large customers. Similarly, natural gas marketers will be free to sell directly to residential and small commercial natural gas consumers. These and other ongoing government initiatives in the oil and gas sector (e.g., royalty reform, pre-tenure planning and public-private partnerships for road upgrades) will support private investment and economic opportunities across the province.

Environmental responsibility will be assured through a clean energy goal, new price signals for conservation, clear emission standards and other strategies.

Electricity distributors will pursue a voluntary goal to purchase at least 50 percent of their new power supply from BC Clean resources that are renewable or result in a net environmental improvement over existing generation. New rate structures (stepped and time-of-use rates) will give better signals for energy saving activity. The government will also expand and update its Energy Efficiency Act and regulations, and will change utility regulatory practices to remove a disincentive to energy efficiency investments by utilities. The Ministries of Energy and Mines and Water, Land and Air Protection are working together on strategies to address climate change and air quality in sensitive airsheds. In other areas, provincial processes for environmental assessment, water licensing and waste permitting are being streamlined. To allow a fair evaluation of

The publicly owned BC Hydro Transmission Corporation will operate BC Hydro's transmission system to ensure fair access for all generators

Actions that support more private sector opportunities:

#4	BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#10	Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.
#11	The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to develop a provincial position, work with the federal government and move effectively toward development of offshore resources.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#14	Under new rates, large electricity consumers will be able to choose a supplier other than the local distributor.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#17	The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#25	Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.
#26	To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

the role of coal-fired generation in B.C.'s electricity future, the Province will adopt emission guidelines for coal-fired power plants that will allow B.C. to compete for investment with neighbouring jurisdictions.

Energy consumers, private investors and B.C. communities will all benefit from the plan, as it is implemented over the next two years.

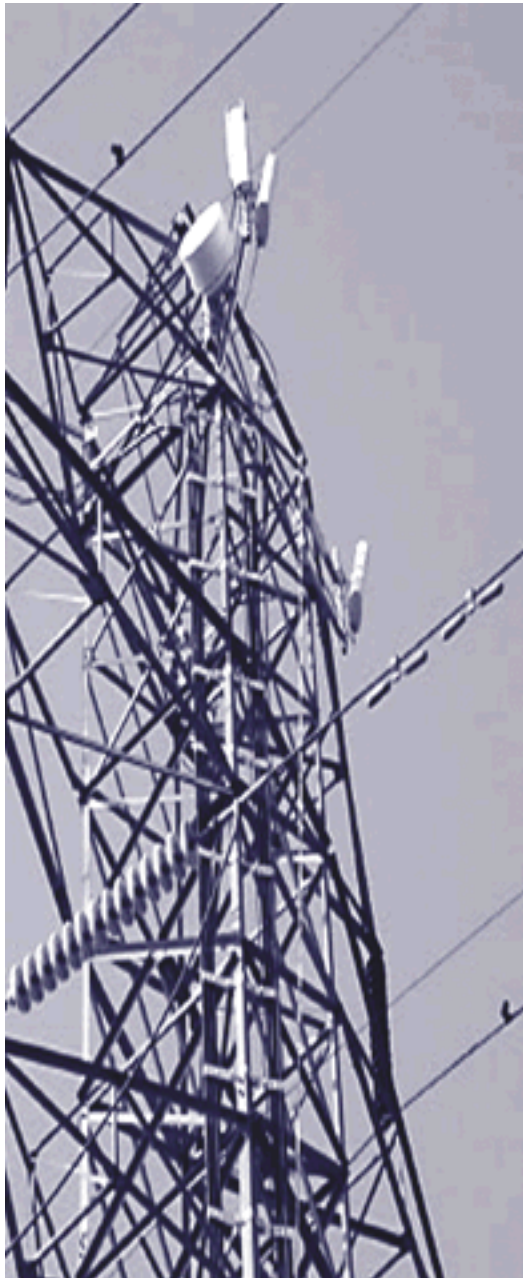
Energy for Our Future: A Plan for BC will be fully implemented by 2004. B.C. consumers will enjoy low electricity rates, greater choice among energy suppliers and potential savings in their electricity and natural gas bills. Private investors will be able to better access and develop new energy resources, while communities will reap the benefits of economic development and local environmental improvement. Taken together, the plan's 26 actions will make the energy sector more resilient and flexible for future changes that will serve British Columbians' interests.

Energy for Our Future: A Plan for BC will be fully implemented by 2004.

Actions that support environmental responsibility:

#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#20	Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.
#24	The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.
#25	Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.
#26	To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

INTRODUCTION



British Columbia's energy sector encompasses all the people, facilities and equipment involved in energy production, delivery and consumption. The sector has been transformed over the past half century. Today, new challenges and opportunities call for an updated energy policy that will support renewed economic growth in the province.

A LOOK BACK

B.C.'s energy sector has changed dramatically during the past 50 years, with public investment in electric power and private development of oil, natural gas and coal resources.

In the early 1950s, energy and the provincial economy looked very different. The energy sector was focused on serving a small domestic resource economy. Energy was supplied by localized monopolies and power rates were relatively high. The next four decades saw tremendous change, from large-scale hydroelectric development on the Peace and Columbia rivers and the construction of major pipelines to expanding oil and gas production in the Northeast, to deregulation of natural gas markets and the emergence of independent power producers. Today, B.C. enjoys a more diversified economy, an extensive network of energy supply facilities, low electricity rates and the benefits of a more competitive, export-oriented energy sector.

Provincial energy policy has evolved along with these changes.

In 1980, the Province of British Columbia released its first energy policy. An *Energy Secure British Columbia* sought to manage energy resources for a secure supply, reduce oil imports and conserve resources. Direct government intervention in energy markets, from setting natural gas prices to building hydroelectric facilities, was the dominant policy direction. At the same time, the BC Utilities Commission was created to provide independent oversight of energy utilities.

The 1980s witnessed a shift from government intervention to market determination of oil and gas prices. In 1985, natural gas markets were opened up and the federal government relinquished control of petroleum markets. A second policy statement, *New Directions for the 1990s*, appeared in 1990, with two new priorities - efficient energy and clean energy; and two left over from the previous decade - secure energy and energy for the economy. The objectives of this policy were to make markets more competitive, send better price signals to consumers, encourage cleaner fuels and energy efficiency and strengthen environmental standards.

Two investigations in the mid-1990s looked at reforming the B.C. electricity market to make it more competitive.

At the request of Lieutenant Governor in Council, the BC Utilities Commission undertook an Electricity Market Structure Review in 1994/95. This review found that the driving forces for electricity reform, in particular high prices, did not exist in B.C. The Commission's report recommended that B.C. move forward with increased competition at the wholesale level (e.g., private power producers selling to BC Hydro) and real-time pricing, which allows large power users to obtain their additional electricity requirements at market prices.[1]

In 1997, a BC Task Force on Electricity Reform was unable to agree on the components of market reform for the province. The head of the task force, Dr. Mark Jaccard, subsequently presented his own proposal for phased electricity reform.[2] Dr. Jaccard's suggestions included establishing an independent grid operator to improve (wholesale) access for competitive suppliers to BC Hydro's transmission system, allowing non-utility suppliers to sell directly to industrial customers (limited retail access), and setting a portfolio standard to require that a percentage of power generation come from environmentally desirable technologies.

Since the release of these reports, some of their suggested reforms have been implemented, including wholesale transmission access, real-time pricing for large BC Hydro customers and retail access for Aquila Networks Canada (formerly West Kootenay Power) industrial customers. Others, such as the independent grid operator and portfolio standard, were not acted upon.

In August 2001, Premier Gordon Campbell commissioned the Task Force on Energy Policy to provide recommendations to government.

After producing an interim report[3] in November 2001, the task force consulted with stakeholders and the public. A final report[4] was submitted to the Minister of Energy and Mines on March 15, 2002, with 46 recommendations in the areas of conservation and energy efficiency, alternative energy, electricity, oil and natural gas, coal and regulation. These recommendations support a series of policy directions that include developing new energy supplies, making markets more competitive, reforming the electricity industry, ensuring sound environmental decisions and harmonizing government regulations. Appendix 1 lists the recommendations in full and provides a government response in each case.

THE PATH FORWARD

B.C.'s new *Energy for Our Future: A Plan for BC* builds on these past efforts with a strategic path for the energy sector.

Energy policy and economic policy are inextricably linked. The government is committed to restoring a strong and vibrant provincial economy with employment opportunities for British Columbians. At the same time, a healthy environment is recognized as one of B.C.'s important natural assets. The purpose of this new policy is therefore to build on the province's energy strengths, in particular our abundant natural resources and low electricity prices, to help revitalize the economy and create jobs in an environmentally responsible way.

There are four cornerstones of B.C.'s plan:

Low electricity rates and public ownership of BC Hydro. Low-cost electricity will be an enduring economic advantage during the next decade. Legislation will entrench the benefits of our publicly owned hydroelectric power assets, and will ensure efficient regulation to keep rates low, maintain industry competitiveness, and support economic growth.

Secure, reliable supply. Stable and dependable energy supplies are increasingly vital in the move to an information economy. To sustain our resource industries and expand the technology sector, energy reliability will be improved and energy markets will be diversified, with more sources of supply, greater competition in electricity generation and enhanced customer choice.

More private sector opportunities. The private sector will be a key partner in the province's energy future. New investment in private power production and continued high activity levels in the oil and gas industry will be critical to realize our full potential as a leading energy supplier in North America.

Environmental responsibility and no nuclear power sources. B.C. has a history of environmentally responsible energy development and one of the best environmental records on the continent. We continue to reject nuclear power and will build on our clean energy strengths with incentives for alternative energy development, new rate signals to encourage energy saving and aggressive strategies for conservation and energy efficiency.

This plan outlines actions the government will take, or has already initiated, to achieve these four objectives.

The plan begins by providing some background on energy production and use in B.C. It then describes several challenges and opportunities currently facing the energy sector. Next, a series of policy actions are outlined in support of the four cornerstones above. The statement ends with a summary of the implications of these policies for consumers, producers, and other participants in the sector. Readers should note that the plan does not address energy use in transportation, which is being dealt with separately through the BC Climate Change Plan and other initiatives underway.

1 British Columbia Utilities Commission, *The British Columbia Electricity Market Review: Report and Recommendations to the Lieutenant Governor in Council*, September 1995.

2 Dr. Mark Jaccard, *Reforming British Columbia's Electricity Market: A Way Forward*, Final Report of the British Columbia Task Force on Electricity Market Reform, January 1998.

3 Task Force on Energy Policy, *Strategic Considerations for a New British Columbia Energy Policy, Interim Report*, November 2001.

4 Task Force on Energy Policy, *Strategic Considerations for a New British Columbia Energy Policy, Final Report*, March 2002.

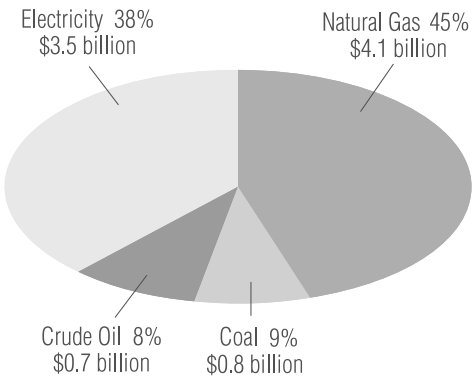
ENERGY FACT

A typical large office building (20-25 stories) will consume 3.5 GWh of electricity per year, equal to the consumption of 350 households.

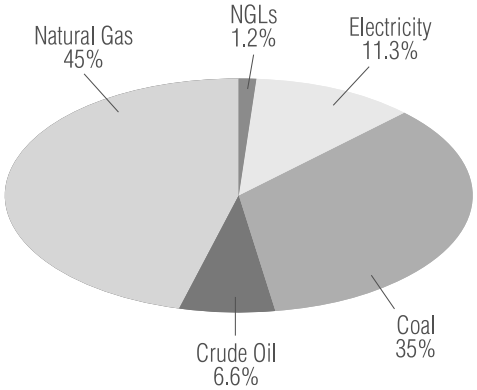
BACKGROUND

VALUE OF BC ENERGY PRODUCTION - 2000

$9.1 Billion total



BC PRIMARY ENERGY PRODUCTION - 2000



Energy is a necessity for and a key driver of B.C.'s economy and quality of life. It contributes to the international trade that is responsible for most of the economic benefits in which we all share. Energy markets continue to evolve with pressures for change in the electricity industry. Appendix 2 provides an overview of the B.C. energy sector.

THE IMPORTANCE OF ENERGY

Energy fuels our daily lives.

British Columbians rely on energy to power their cars, run their appliances, equipment and industrial plants, and light and heat their homes, communities and businesses. Perhaps nowhere is the importance of energy more evident than in the case of electric power. Whereas 20 years ago the average home had relatively few appliances, today it has a computer, two TVs, a dishwasher, microwave oven, VCR and DVD player, among other items. New technologies such as high resolution TVs can consume significantly more energy. Likewise, the typical office is now equipped with computers, photocopiers, fax machines and other electricity-using equipment.

Energy also drives the provincial economy.

Energy is a significant input into the production of other resource commodities. The energy-intensive sectors of forest products, mining, refining, and chemicals together make up 70 percent of provincial exports. These sectors, facing tough competition in the global marketplace, must control costs and increase efficiency and productivity to maintain their economic advantage.

Access to reliable, low-cost energy is also important for attracting and developing the technology sector in B.C. Technology firms are particularly dependent on a continuous supply of electricity, as shown by California's recent energy crisis. The Silicon Valley Manufacturing Group has estimated that its almost 200 members lost more than $100 million during one day of rolling blackouts in June 2000.[5]

The energy sector itself is a major source of economic activity.

The sector as a whole (electricity, natural gas, oil and coal) employs about 35,000 people. Energy accounts for about four percent of provincial gross domestic product, the value of our economy's output.

Revenues to energy industries totaled $9.1 billion in 2000, and direct revenues to government exceeded $3 billion. The oil and gas industry, at $1.8 billion in 2000, is B.C.'s largest source of natural resource revenues that help to fund health care and education. In 2001/02, lower prices resulted in a decline of $650 million to the Province. Dividends, water rentals, and taxes from BC Hydro yield in the order of $700 million annually. Aside from its employment and revenue benefits, energy contributes to regional development, primarily in the Northeast and Southeast, but increasingly with opportunities across the province.

THE ROLE OF TRADE

An export orientation has allowed energy resources to be developed at lower cost for British Columbians.

British Columbia currently exports two-thirds of the energy it produces. Much of today's network of energy production and delivery facilities would not exist had resources been developed only to serve provincial consumers. Examples include an extensive hydroelectric system on the Peace and Columbia rivers, the Duke Energy (formerly Westcoast Energy) pipeline bringing natural gas to Vancouver, and natural gas drilling in the Northeast. A strong export orientation has allowed the energy sector to take advantage of economies of scale and develop resources at lower cost. This, in turn, has resulted in reliable and reasonably priced energy service for B.C. consumers.

Electricity trade helps ensure low power rates and reliability for domestic consumers.

The province's flexible hydroelectric system, with its large reservoirs for storing water, enables highly beneficial trade in electricity. BC Hydro earns revenues by importing electricity when market prices are low and exporting electricity when prices are high, while at all times satisfying domestic power needs. The net revenues from this trade help keep provincial rates low and stable.

Imports also help meet electricity requirements during times of reduced water inflows into B.C. reservoirs. BC Hydro can earn significant trading income even in low water years, when the province is a net importer, because of the flexibility of our large hydroelectric and reservoir systems. Net trading revenue averaged around $100 million annually during the 1990s.

Our clean energy exports contribute to continental energy security.

B.C.'s hydro-based electricity exports offer a source of clean, reliable power for consumers in the United States and Alberta. In US markets, our natural gas displaces oil and coal used to generate electricity. With growing North American demand, especially for natural gas used in power plants, B.C. has a key role to play in supporting continental energy security. Continued integration with regional power markets will provide better access to reliable, low-cost electricity for our export customers and provincial consumers alike.

B.C.'S ENERGY STRENGTHS

We have extensive undeveloped energy resources for new supply and a significant potential to further reduce energy use.

Discovered reserves of natural gas are sufficient to meet domestic and export needs for the next decade. Undiscovered reserves of natural gas, including coalbed methane, could add decades of new supply, but will require further exploration to be realized. Coal resources, if used for electricity production at B.C.'s current electricity consumption rate, could last well over a century.

While there are considerable resources remaining for large hydroelectric development, many are on protected rivers. The potential for other renewable electricity, including small hydro, wood residue, wind and tidal energy, is growing over time as technologies improve and costs decline. In total, new conventional (available large hydro, natural gas-fired and coal-fired) and alternative energy resources are currently estimated at more than double existing generating capacity. In addition, BC Hydro estimates that 10 percent of total electricity demand could be economically saved by 2015, through increased conservation and energy efficiency.

Biofuel technologies are under development to convert plant material such as wood waste into ethanol and other transportation fuels. B.C. has enough wood residue to produce over 300 million litres of ethanol annually. Ethanol is blended with gasoline and diesel fuel to add oxygenation, extend conventional fuel supplies and reduce transportation-related emissions.

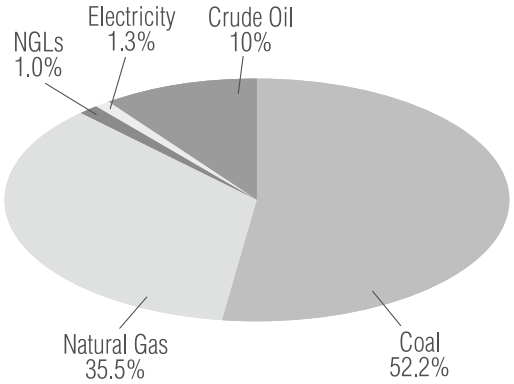
A diverse, reliable energy supply network has evolved in the province.

The energy sector is large and diverse. It comprises substantial production of hydroelectricity, natural gas, coal and oil. Highly developed systems of pipelines and power lines deliver energy to domestic and export consumers. B.C. companies are also pursuing leading-edge alternative technologies, such as fuel cells, and innovative ventures in wind, wave and solar power.

Electric utilities and natural gas suppliers have a proven record of providing reliable energy for both the provincial and export markets. Natural gas suppliers ensure reliability by upgrading production facilities and pipeline capacity to meet growing demand. Electricity suppliers do so by

Electricity trade helps ensure low power rates and reliability for domestic consumers.

BC ENERGY EXPORTS - 2000



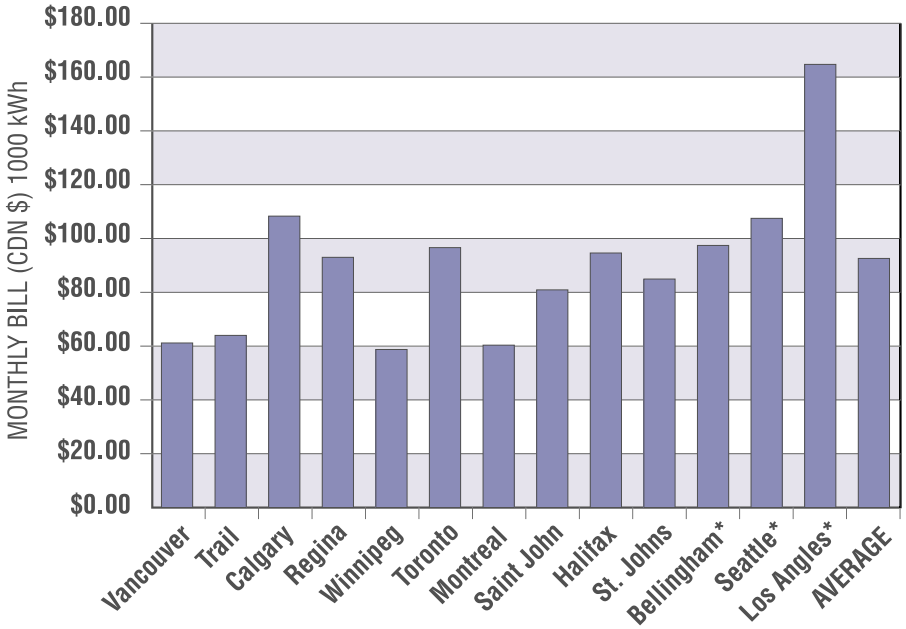
Low electricity rates and public ownership of BC Hydro

maintaining capacity and energy reserve margins (buffers of extra available generation and transmission), developing and applying short-term reliability standards, and participating in a western North American electricity reliability network.

Low electricity rates reflect major public investments in hydroelectric power made a generation ago.

Our electricity rates are among the lowest in North America. A previous generation's investment during the 1960s and 1970s has benefited all British Columbians over the past two decades. Today, hydroelectric facilities on the Peace and Columbia rivers account for approximately 75 percent of BC Hydro's generating capacity. Together with its coastal hydroelectric and thermal power plants, these heritage assets produce electricity at a much lower average cost than the cost of new generation or prices in neighbouring markets.

COMPARISON OF RESIDENTIAL ELECTRICITY RATES



B.C.'s low electricity rates are the direct legacy of abundant hydroelectric resources and a flexible power system that has enabled trade.

Some jusisdictions have a legacy of public investments in nuclear power, which has proven to be far less reliable as an energy source and far more costly than B.C.'s hydro-based system.

Our advantage in energy technologies offers domestic and export opportunities.

British Columbia profits from a growing alternative fuel industry, as well as expertise in hydroelectric power. The growth of firms such as Ballard Technologies (fuel cells) and Westport Innovations (natural gas vehicles) demonstrates our capacity for technology development. A recent survey of renewable energy strengths identified the Pacific Northwest as having the potential to become a world leader in solar photovoltaics and power transmission technologies.[6] This technological know-how can be used to develop new energy supplies within the province, and to generate additional revenues and jobs from trade.

CHANGING ENERGY MARKETS

Canadian natural gas markets have been deregulated since 1985.

In 1985, the federal government and western provinces agreed to deregulate natural gas to allow consumers to make their own purchase arrangements. Since then, high-volume industrial and commercial consumers have been able to purchase directly from natural gas producers as an alternative to the local distribution utility. All major pipelines provide open access, and an interconnected North American market now functions with little government intervention.

Other jurisdictions have reformed their electricity markets, with mixed success.

Electricity market reform has taken place in a number of other countries, including Great Britain, Norway, Australia, New Zealand, Argentina, Chile, and parts of the United States. In Canada, Alberta and Ontario have significantly restructured their electricity sectors. The rationale for change has generally been to support broader economic reforms (i.e., privatization), reduce electricity prices, and/or comply with access rules in interconnected markets. While there have been many successes in electricity reform, poor timing, inadequate planning, and a lack of regulatory foresight have led to difficulties in some jurisdictions.

The extent of market reform varies in other jurisdictions.

In general, reforms are intended to reduce costs by making electricity markets more competitive. Integrated utility monopolies are typically unbundled into separate generation, transmission and distribution entities. In some cases, generation and distribution are privatized and further divided into multiple companies to create competition. The transmission system is opened up, allowing private generators to sell to the distribution company (wholesale access/competition). A market is usually established to determine competitive pricing for this power. Private generators may also be allowed access to the distribution system, so that they can sell directly to electricity consumers (retail access/competition). Most jurisdictions undertaking such reforms have had power rates significantly higher than those in B.C.

B.C.'s electricity industry has undergone some changes over the past decade.

In the late 1980s, BC Hydro began requesting new generation projects from independent power producers (IPPs). Access to its transmission system, and to Aquila Networks Canada's system, was opened up in 1996. This allowed IPPs to use the transmission network to sell power into the export market, and BC Hydro's export subsidiary (Powerex) to trade directly in US wholesale markets. Starting in 1998, Aquila Networks Canada offered retail access to industrial customers. In June 2001, at the request of the BC Hothouse Growers' Association, the BC Utilities Commission granted approval to IPPs to access BC Hydro's distribution system. Most recently, BC Hydro has been reorganizing into functional business units for generation, transmission, and distribution, in order to make its operations more transparent and cost-effective.

***Energy for Our Future: A Plan for BC* provides a measured response to continue improving our power market.**

B.C. is not ready for, or in need of, large-scale electricity reform. To function properly, competitive markets require many buyers and sellers. Despite the recent growth in private power, the B.C. market is still dominated by a large Crown corporation with a concentration of low-cost generating assets. Moreover, our low power rates do not provide the same impetus for widespread reform as in higher-cost jurisdictions. At the same time, there are opportunities to introduce more competition in the development of new sources of electricity supply, while preserving the benefits of low-cost generation and trade revenues for provincial consumers. This plan includes actions to do just that.

5 United States, National Energy Policy, Report of the National Energy Policy Development Group, May 2001, p. 2-8.
6 Planit Management, Compass Resource Management, and Steeple-jack Consulting, Poised for Profit, Report Prepared for Climate Solutions, November 2001.

Energy for Our Future: A Plan for BC provides a measured response to continue improving our power market.

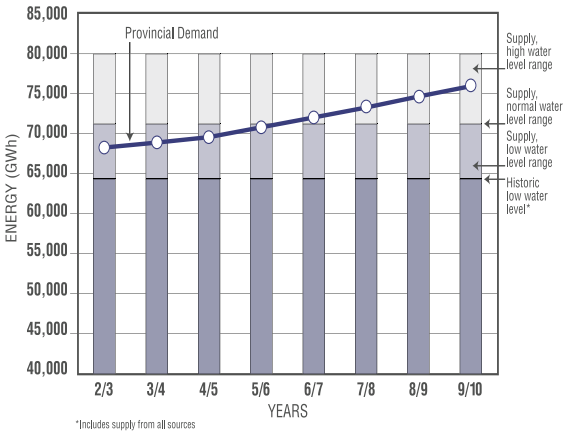
CHALLENGES

ENERGY FACT

A large industrial consumer, such as a pulp mill, might use 400 GWh of electricity anually, equal to the consumption of 40,000 households.

Demand for electricity is rising at an average 1.7 percent per year

PROVINCIAL ELECTRICITY SUPPLY / DEMAND OUTLOOK



*Includes supply from all sources
Source: Energy Task Force Working Group on Electricity, based on data from BC Hydro and Utilicorp Networks Canada.

The B.C. energy sector faces new and ongoing challenges with respect to maintaining energy security, low electricity rates, and a clean environment. These challenges must be addressed if we are to seize on opportunities to develop the sector and strengthen our economy.

THE NEED FOR ENERGY SECURITY

B.C. needs secure, reliable energy to help revitalize the provincial economy.

The development of abundant energy resources was instrumental in establishing our resource-based economy and high standard of living. Key industries, such as forestry, mining, aluminum and chemicals require reliable and affordable energy to keep their economic advantage in world markets. For emerging technology industries, electricity reliability is especially crucial. Secure and reliable energy supplies are needed to drive the new digital economy and support a modern lifestyle that depends increasingly on electric energy for work and leisure.

After a decade of poor economic performance, the government aims to restore B.C. to a leadership position among Canadian economies. Stronger economic growth will mean more demand for energy. Energy development and use that preserve the economic advantage of our industry and provide opportunities for new investment, jobs, revenue and regional growth are integral to the Province's economic policy.

With growing energy demand and aging facilities, investment in new supply is critical.

BC Hydro customer demand is rising at an average 1.7 percent per year.[7] Most of the Crown corporation's generating facilities have been operating for 30 years or more. Significant capital expenditures are required to upgrade existing generation and transmission, so that B.C. consumers will continue to have reliable electricity. Even with this upgrading, the pressing need for power on Vancouver Island (see box) means that additional generation must be installed by 2004.

Similarly, the natural gas supply system is strained, with heavy loading of pipelines at certain times. BC Gas expects demand to grow by one percent annually until 2007.[8] New pipeline capacity must be built to ensure reliable natural gas supplies at reasonable prices for provincial consumers. In addition, northern roads and gas processing facilities must be upgraded to enable exploration, development, and production of natural gas.

Unless new domestic supplies are developed, B.C. will become more dependent on imported energy and vulnerable to price swings.

Imports fulfill a useful role in B.C.'s energy picture. Most of the oil and refined petroleum products (gasoline, diesel fuel, aviation fuel, etc.) we use are imported from Alberta. About 90 percent of these products, consumed in central and southwestern B.C., are transported by pipeline from Alberta.

In the past two years, BC Hydro was a net importer due to low water levels. These imports were necessary to meet domestic electricity requirements. However, over-reliance on imports at wholesale spot market prices could expose B.C. consumers to price volatility in western power markets. The province

The Power Need on Vancouver Island

Vancouver Island's population has grown by 20 percent since 1991, creating more demand for electricity. Electric heating loads are heavier on the Island because natural gas for home heating has only been available for a decade. Total demand on the Island is rising by 30 to 40 MW annually – enough power to light and heat an extra 30,000 to 40,000 homes a year.

With the recent addition of the natural gas-fired Island Cogeneration Plant, local generation currently meets 33 percent of Vancouver Island's power needs. The remainder is supplied from generation on the Mainland via submarine cables, some of which are now more than 45 years old. These cables are due for retirement, and BC Hydro has determined that new electricity supply to replace them will be needed by 2004.

must develop new generation to serve rising demand, or we may experience electricity shortages similar to those in other jurisdictions.

California's recent difficulties with high prices and rolling blackouts show what can happen when poor electricity market design combines with insufficient resources for demand growth. Over the past decade, local opposition to energy development prevented the state from building new power plants. Since the crisis of 2000/01, California has taken steps to restore energy security, including expediting the siting of new in-state power plants.

To avoid costly public investments, governments everywhere are looking to the private sector for new energy development.

In B.C., as in most other provinces, private investment has developed the oil, natural gas and coal industries, while public investment has dominated electricity because of the high cost of large-scale power systems. Given competing priorities for public funds, the government is interested in shifting the responsibility for new power development to the private sector. The advent of new small scale power plants, such as efficient combined cycle gas turbines and small hydro plants, is making it easier to match electricity supply with gradually growing demand. These plants are lower risk and lower cost than the much larger facilities that were the norm of the past. Private power producers, who can compete to bring forward projects to meet B.C.'s growing demand, have the capability and core competency for developing smaller generation resources as an alternative to public investment by BC Hydro.

Access to energy resources is hindered by uncertainty over land use planning and First Nations claims to rights and title, as well as poor quality roads in the North.

The fossil fuel industries require physical access to land to explore for and develop resources. Without access to areas of high resource potential, such as the Muskwa-Kechika Management Area in the Northeast, the oil and gas sector will not be able to sustain its growth. This requires timely land use planning to provide more certainty for exploration and development. Better access is needed not only in traditional areas, but also in regions of the province that are new to particular resource development (e.g., interior and offshore oil and gas basins and coalbed methane across the province).

Poor road networks limit access to resources in northeastern B.C. Most of these public roads were not built to withstand heavy use by the oil and gas industry. Seasonal road bans are getting longer and severely restrict industry activity.

KEEPING ELECTRICITY RATES DOWN

Frozen since 1996, BC Hydro rates require scrutiny in a public process to ensure that they reflect the true costs of electricity.

Under the rate freeze, the BC Utilities Commission has not been able to fulfill its mandate to publicly examine BC Hydro rates. Recently, BC Hydro costs have increased as demand has grown, new supplies have been added and existing facilities have required maintenance. Keeping energy costs down is essential to maintaining B.C.'s economic advantage. Returning BC Hydro to independent oversight by the BC Utilities Commission will ensure that rates remain as low as possible.

Continued trade and access to US markets is necessary for low and stable rates.

The export market provides income to supplement domestic power revenues and maintain low rates. In the United States, proposed new market rules will require an independent entity, separate from generation and distribution, to control the transmission system. This is part of a series of changes being implemented by the US Federal Energy Regulatory Commission, or FERC (see box). B.C. is participating in the development of the western Regional Transmission Organization (RTO West). The Province recognizes the value of integration with US power markets in the revenue, ratepayer and reliability benefits that can be realized.

Environmental responsibility and no nuclear power sources

ENVIRONMENTAL PRIORITIES

Low electricity rates discourage conservation and energy efficiency. Reducing energy use improves the environment, while saving consumers money.

Conservation means cutting energy use, for example by turning down a thermostat or shutting off lights. Energy efficiency means getting more productive use out of energy consumed, for example by purchasing a new furnace that uses less fuel to heat a home. Besides directly lowering consumer energy bills, these activities reduce demand and defer the need for new supply. This avoids costly energy investments and the environmental impacts from development.

Low power rates based on the blended cost of old and new electricity supplies provide a poor price signal for encouraging energy-saving activity. The reason is that, under blended rates, consumers do not see the cost of new electricity supply when deciding how much energy to use. With B.C. electricity rates roughly half the cost of new production, there is currently little incentive for increased conservation and energy efficiency.

Strategies are needed to protect provincial airsheds and watersheds from the effects of energy development and use.

Fossil fuel production and power generation are B.C.'s fastest growing source of the manmade greenhouse gas emissions that have been linked to global climate change. The development and use of energy also have significant implications for sensitive airsheds, such as the Lower Fraser Valley. Province-wide, the largest contributor to local air pollution is energy use in transportation, accounting for almost half of smog-forming pollutants.[9] For community watersheds, a key concern is the impact of hydroelectric power operations on fish habitat, recreation and tourism and other water uses. Effective strategies are required to manage all of these environmental impacts.

Unclear or overly prescriptive environmental standards and inefficient regulatory processes impede sustainable energy development.

To meet the needs of a growing economy, new energy supplies must be developed in a timely, cost-effective, and environmentally responsible manner. Energy developers are

US Market Rules and Regional Transmission Organizations

For the past decade, the US Federal Energy Regulatory Commision (FERC) has been developing rules to make US power markets more competitive and efficient. In 1996, electric utilities regulated by FERC were required to open up access to their transmission systems. Another ruling in 1999 encouraged the transfer of operational control to an independent Regional Transmission Organization, or RTO. Having a large geographic region operated by one independent transmission entity helps ensure a coordinated planning to reduce transmission bottlenecks, facilitate trade and increase reliability. It also encourages private power development through access to competitive wholesale markets.

In August 2002, FERC released a proposal for standard electricity market design, to address transmission under-investment, discriminatory access, and other problems in wholesale power markets. Proposals include the independent operation of transmission, a single open access tariff for all transmission users, and procedures to ensure the long-term adequacy of power supplies. For B.C., this means trade and power development opportunities, reliability benefits of integration and non-discriminatory access to competitive export markets to keep rates low and preserve access to B.C.'s heritage energy.

B.C. has been taking part in the development an RTO covering the Pacific Northwest. RTO West will operate US transmission systems on behalf of their owners, as well as the region's wholesale power market. In September 2002, FERC accepted most of the current RTO West proposal. Independent governance is expected to be in place by the fall of 2004, with a fully operational RTO by 2006.

ENERGY FACT

B.C.'s greenhouse gas emissions per capita is 29% lower than the national average.

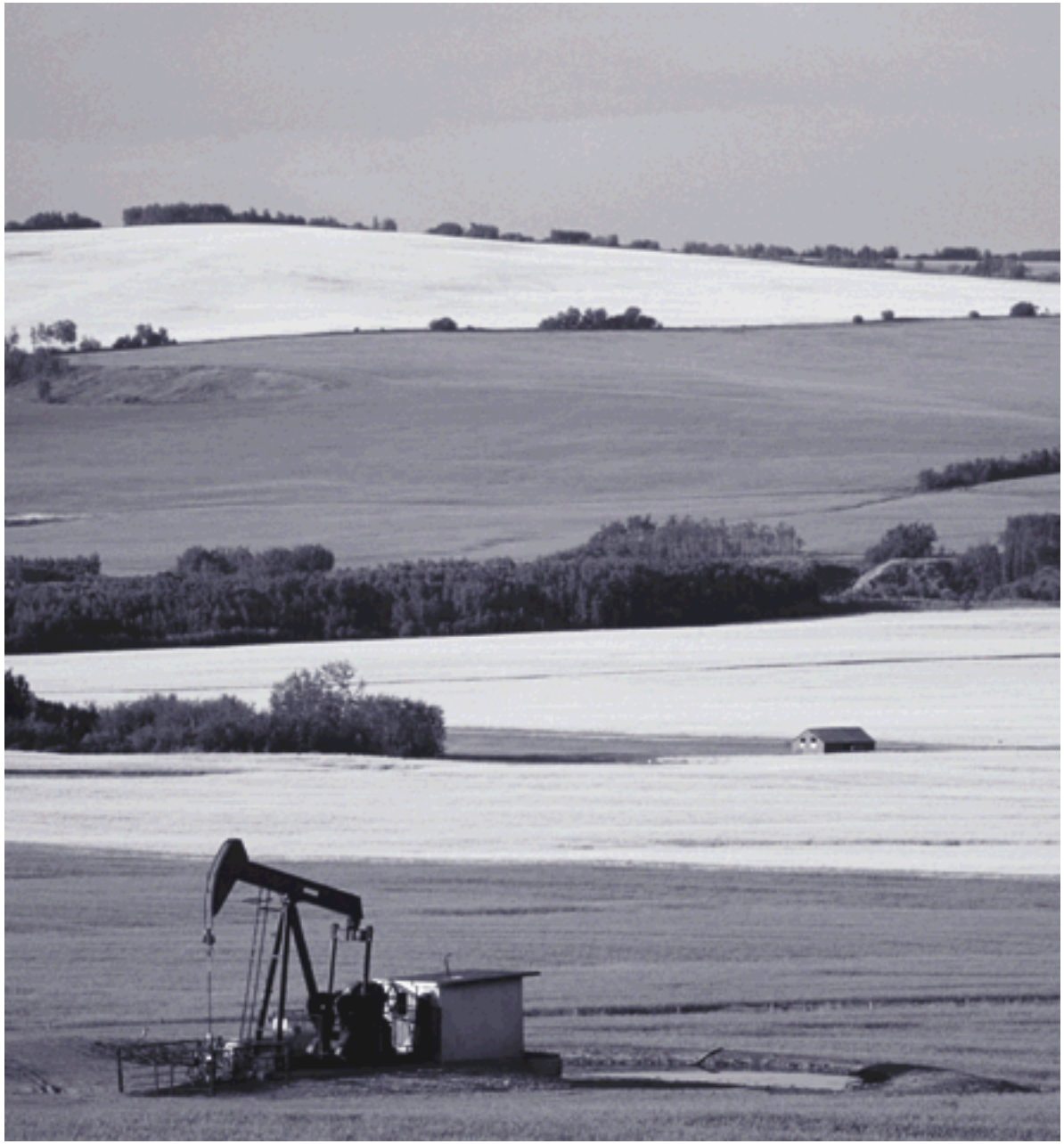
seeking clear, scientifically based environmental standards. The coal industry, as an example, has requested final air emission standards for coal-fired boilers, consistent with those adopted in Alberta, to provide more certainty for potential electricity development in B.C. Long environmental assessment reviews, backlogs in water licensing, and other regulatory inefficiencies currently add to the costs of energy projects, including those where the impacts and mitigation measures are generally well understood (e.g., small hydro plants).

7 BC Hydro. www.bchydro.com/policies/demandgrowth/demandgrowth771.html.

8 BC Gas, BC Gas 2003 Revenue Requirement application, excluding Centra Gas and Burrard Thermal.

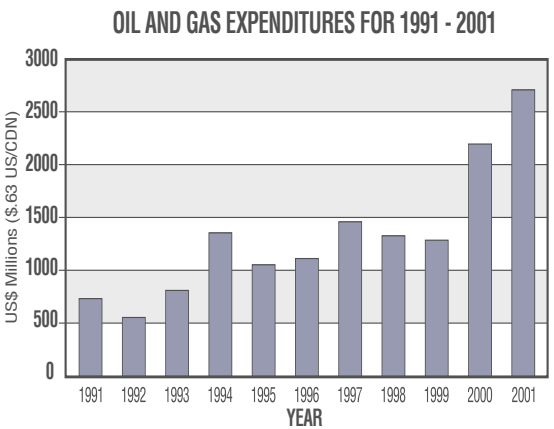
9 2000 Emission Inventory for the Lower Fraser Valley Airshed.

Unclear or overly prescriptive environmental standards and inefficient regulatory processes impede sustainable energy development



OPPORTUNITIES

B.C.'s large, untapped energy sources include oil, natural gas and coal, as well as coalbed methane and other clean sources such as small hydro, wood residue, wind and ethanol.



The energy sector has the potential to generate new investment, increased trade, and economic growth in an environmentally responsible manner. *Energy for Our Future: A Plan for BC* needs to support efforts to take advantage of these opportunities for the benefit of all British Columbians.

ENERGY FOR A STRONGER ECONOMY

B.C. electricity can be made even more reliable in support of a growing information economy.

Reliable power supply is increasingly important in the move to a digital economy. B.C. electric utilities are developing specialized products and services to offer higher-than-normal reliability for customers such as technology firms. Continued integration of the western electricity market will help to facilitate trade and coordinate transmission planning to remove bottlenecks. It will ensure better access to low-cost generation throughout the western power system.

Our natural resources, talent and technology provide many diverse opportunities for meeting demand growth as efficiently as possible.

B.C. is fortunate to have a growing natural gas industry, significant hydroelectric and alternative energy resources, and large deposits of coal and coalbed methane. We also have considerable potential to save more energy through cost-effective conservation and energy efficiency. Homegrown technologies and expertise can help develop a more diverse and innovative energy system.

With smaller natural gas-fired plants, it is possible to site new generation close to customer demand, reducing transmission costs. Energy efficiency, alternative energy and coalbed methane can generate jobs and investment in regions new to energy development. Overall, there are opportunities to develop new energy resources throughout the province.

Increasing energy trade can improve domestic reliability, enhance continental energy security, and create economic benefits for British Columbians.

In the United States, natural gas use is forecast to grow by more than 50 percent through the year 2020.[10] For electricity generation alone, over 90 percent of planned power plant additions are expected to be fuelled by natural gas. With its conventional natural gas basins in decline, the US is looking to its frontier areas, such as Alaska and the deep Gulf of Mexico, as well as to Canada for new supplies. Modernizing and expanding delivery networks for both natural gas and electricity are part of the US energy policy, which will provide better access to markets for our energy exports.

US electricity demand is projected to rise by more than 45 percent by 2020.[11] Some 22,000 MW of new generation, twice the electrical capacity of BC Hydro, is currently under construction in Western North America.[12] Among other things, these capacity additions have resulted in electricity prices returning to normal levels. Since most of the new facilities will be gas-fired generation, the additional fuel demand could be a boon to our natural gas exports. B.C.'s storage capability, together with north-south differences in production costs and the timing of electricity demands and prices, will ensure ongoing opportunities for trade. Aside from the benefits for provincial consumers, increased access to US wholesale markets can support private power development in B.C.

The private sector has the financial and technical ability to provide new investment in energy supply, with opportunities for jobs and economic growth across B.C.

Since the late 1950s, private companies have invested billions of dollars to develop successful, market-driven fossil fuel industries in the province. The recent high levels of investment in natural gas drilling are expected to continue with expanding demand in domestic and export markets. Exploration and development of oil, natural gas, and coalbed methane outside the Northeast, including interior and offshore basins, can generate investment, jobs, and economic spin-offs throughout B.C.

Historically, as a Crown corporation, BC Hydro was able to access low-cost capital to build its extensive hydroelectric system dominated by mega-projects. Today, with new small generation technologies and more sophisticated capital markets, public investment is no longer required. Independent power producers are willing and able to develop new generation in the province, providing they have reasonable access to the transmission system and there is a level playing field for public and private investment. Compared to large centralized power plants, the development of many scattered IPP projects can mean more jobs and greater opportunities for regional development. Despite the recent difficulties of some energy companies in North America, the private sector has a useful role to play in B.C.'s electricity future.

Land use and pre-tenure planning, closer cooperation with First Nations, and road upgrades can improve access to energy resources.

Pre-tenure plans are required only in the Muskwa-Kechika Management Area, before oil and gas tenures will be issued. A pre-tenure plan identifies sensitive resource values and strategies for environmentally responsible resource development. Both pre-tenure and land use planning processes enable better access to energy resources by clarifying the conditions under which exploration and development can occur. Efforts are also underway to work with First Nations on economic opportunities from resource development. Public-private partnerships will continue to improve road networks in the Northeast.

Performance-based Rate Regulation

Until recently, electricity and natural gas rates were set through cost-of-service regulation and adversarial public hearings. The utility would estimate the costs, including a rate of return, required to serve its growing system. After a public hearing before the BC Utilities Commission, rates would be established for the different classes of customers depending on their share of demand.

Utility rates are typically now determined through negotiated settlements and using performance-based regulation (PBR), which sets targets or caps for pricing. Under this approach, rates are allowed to increase by the inflation rate plus a factor for system growth, minus an efficiency factor. If the utility is able to do better than the specified efficiency factor, then it can retain the cost savings for its shareholders and/or ratepayers in the period between rate settings.

ENSURING OUR ECONOMIC ADVANTAGE

B.C.'s existing low-cost generation is a source of long-term benefit for provincial consumers.

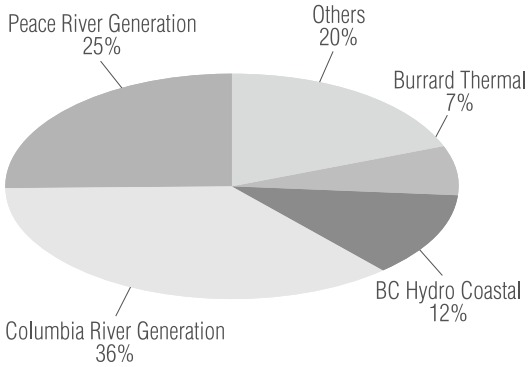
Unlike some other jurisdictions in North America, the province is not encumbered with large unpaid investments in high-cost generation (e.g., nuclear power) that have driven up electricity prices. Instead of stranded investments there are stranded benefits captured in our heritage power assets. These benefits arise from the difference between what it currently costs to produce electricity on the BC Hydro system and what it would cost to replace that electricity in the marketplace (natural gas-fired generation). There are mechanisms available to secure these benefits for BC Hydro ratepayers over an extended period.

Performance-based regulation offers an efficient regulatory tool for getting power rates right.

The provincial Utilities Commission Act (UCA) is designed around inquiries and adversarial public hearings as the basis for regulating energy utilities. In recent years, however, the Utilities Commission has increased its use of negotiated settlements and performance-based regulation. PBR employs multi-year pricing targets and interest-based negotiations among stakeholders, rather than costly adversarial hearings. This form of regulation better aligns shareholder and ratepayer interests by allowing utilities and customers to share the savings from cost efficiency, encouraging further investment and helping to keep energy rates low.

B.C.'s economic advantage includes low cost electricity and public ownership of BC Hydro

BC's 2001 ELECTRICAL GENERATION CAPACITY

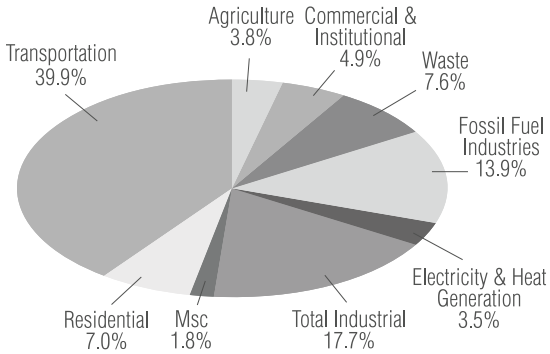


ENERGY FACT

A compact flourescent light bulb uses one-quarter the energy of a standard incandescent bulb.

Environmental responsibility and no nuclear power sources

BRITISH COLUMBIA'S GREENHOUSE GAS EMMISIONS BY SECTOR (2000)



Source: Environment Canada, Canada's Greenhouse Gas Inventory 1990-2000, June 2002

EFFICIENT ENVIRONMENTAL MANAGEMENT

B.C. has the capability for more aggressive conservation, energy efficiency, and alternative energy development, as cost-effective ways to protect the environment.

Since the late 1980s, provincial utilities have amassed experience with conservation and efficiency through programs offering rebates and other customer assistance (e.g., Power Smart, Power Sense, Homeworks). Expertise is also vested in private energy service companies and B.C. businesses have initiated their own energy-saving activities. BC Hydro estimates that 10 percent of total electricity demand could be economically reduced by the year 2015. There are opportunities for more aggressive conservation programs by distribution utilities, stronger energy efficiency standards for appliances and equipment and other energy-reducing strategies.

While conservation and energy efficiency avoid impacts on the environment, alternative energy results in smaller environmental impact than conventional energy development (i.e., coal, oil, natural gas, and large-scale hydroelectricity). B.C. has significant resources of small hydro, wood residue, wind, solar and tidal power, some of which could be developed at costs that are competitive with conventional power. BC Hydro has voluntarily agreed to meet 10 percent of new energy requirements between 2001 and 2010 from clean energy purchases. BC Hydro's requests for power to date have met with an overwhelming response from the private sector.

Alternative electricity rate structures offer better price signals to encourage energy-saving investments and behaviour.

Stepped power rates that charge a higher price as energy consumption increases give consumers the incentive to undertake conservation and energy efficiency without increasing the average electricity rate. Time-of-use rates that charge a different price for power depending on the time of day or season encourage consumers who can manage the timing of their electricity use to shift away consumption from higher-priced periods of peak demand. Both of these rate structures have been used successfully in other jurisdictions to save consumers money, reduce utility costs and protect the environment.

Greenhouse gas and airshed management, as well as land and water use planning, can help control the environmental impacts of energy development and use.

Cost-effective actions are available to manage air emissions. For example, through measures such as AirCare, cleaner automobile emissions, and cleaner factories, air pollution in the Lower Mainland has declined by about 40 percent since 1985.[13] The Province has committed to manage the growth in BC's greenhouse gas emissions, and to protect threatened airsheds. These commitments underscore the link between sound energy and environmental policies.

In the Northeast, land use and pre-tenure plans are reconciling industry access to energy resources with concerns for environmental protection. Similarly, BC Hydro is conducting 23 multi-stakeholder water use planning processes to determine hydroelectric operating rules that balance power production, fish habitat, recreation, and other water uses. This process is scientifically based, engages multiple interests in the resource, and will amend existing water licences to reflect contemporary values. A total of nine completed water use plans are anticipated by winter 2003, with the rest expected to be completed by winter 2004.

Clear environmental standards, streamlined approval processes and results-based regulation can ensure lower-cost, environmentally responsible energy development.

Explicit, scientifically determined standards for air emissions, water discharges, and other impacts can be used to screen out environmentally unacceptable projects. Then, efficient regulatory processes can reduce development costs for projects that are considered prudent. Provincial processes, including environmental assessment reviews, air emissions

permitting, and oil and gas development approvals are all moving to results-based regulation. This approach sets clear standards and then allows flexibility for finding the most economical means to achieve them.

Nuclear power is not part of B.C.'s energy future.

Nuclear power is supported by some as a way to satisfy growing energy generation and address climate change, since this form of thermal generation does not produce greenhouse gas emisions. However, the financial and environmental problems experienced in other jurisdictions that have invested in nuclear power make it a risky proposition. The province rejects nuclear power as a strategy to meet the needs of British Columbia.

[10] US National Energy Policy.
[11] Ibid.
[12] Northwest Power Planning Council and Cambridge Energy Research Associates.
[13] Lower Fraser Valley Ambient Air Quality Report.

Energy and greenhouse gas emissions

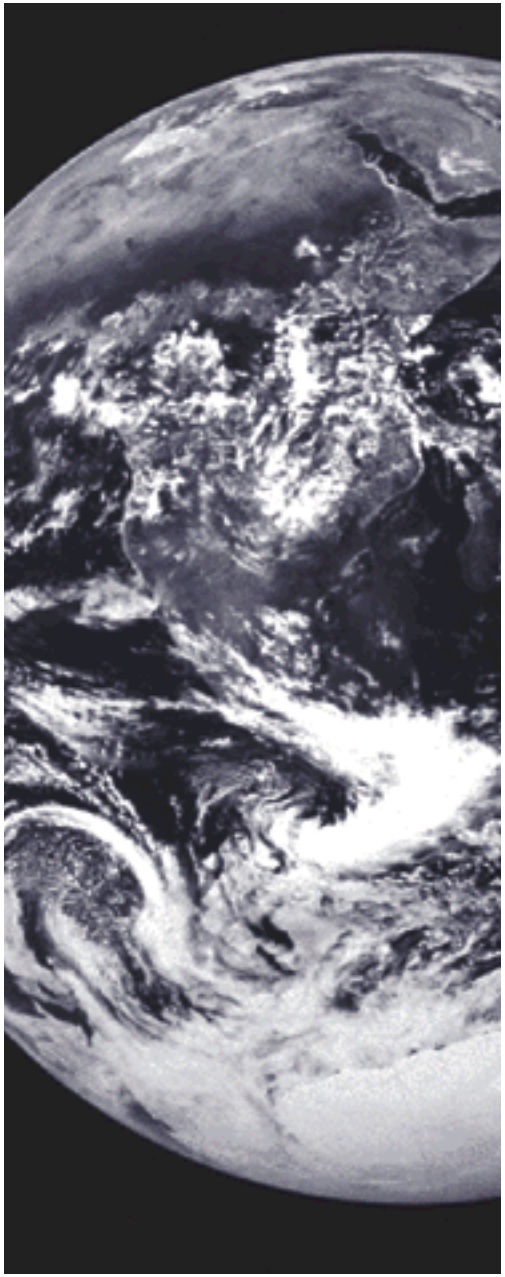
Energy production accounts for about 17 percent of B.C.'s greenhouse gas emissions, lower than the national share (34%) because of our extensive hydroelectric system. While transportation makes up the largest share (40%) of provincial emissions, the electricity and fossil fuel industries are expected to be the fastest growing sources of continuing emissions growth, with their combined emissions forecast to double between 1990 and 2010.

The rapid growth in energy sector emissions reflects the shift to efficient gas turbines for electricity generation and expansion in natural gas production and exports. Although the province's natural gas exports represent clean energy to US buyers, displacing coal and oil, the emissions upstream production and transmission add to provincial emissions.

The energy sector is acting to voluntarily reduce its greenhouse gas emissions production. For example, BC Hydro has committed to offset half the emissions from new gas-fired plants on Vancouver Island through energy efficiency, fuel switching, and other measures. The oil and gas industry has adopted standards to control the emissions from flaring of natural gas that accompanies production. The Ministry of Energy and Mines promotes the reinjection of acid gas into existing natural gas wells to reduce harmful air emissions.

ENERGY FACT

Air pollution in the Lower Fraser Valley are estimated to have declined by approximately 40% between 1985 and 2000.



A legislated heritage contract will help to preserve B.C.'s low electricity rates

In response to these challenges and opportunities, British Columbia needs to make some changes to the energy sector to encourage new investment and increased trade, while ensuring continued low power rates and environmentally responsible energy development. A series of policy actions will be implemented, or are already underway, to achieve these objectives.

LOW ELECTRICITY RATES AND PUBLIC OWNERSHIP OF BC HYDRO

Low rates for B.C. consumers will be entrenched by assuring the benefits from existing generation and trade, preserving publicly owned power assets, outsourcing services where economical, and re-regulating BC Hydro rates so that they recover the costs of production.

THE BENEFITS FROM LOW-COST GENERATION AND TRADE

Policy Action #1 (new): A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.

The heritage contract will essentially lock in the value of existing low-cost generation assets for an extended period. It will be implemented through legislation that specifies the term and amount of energy involved. The contract's term will initially be 10 years, with provisions for renewal thereafter, and the quantity of energy will be the production from BC Hydro's system under average water conditions. The BC Utilities Commission will review and recommend the terms and conditions for the heritage energy based on a return consistent with private utilities. The heritage contract is similar to arrangements that have been adopted in Quebec (see box).

Policy Action #2 (ongoing): BC Hydro ratepayers will continue to benefit from electricity trade.

Electricity trading markets are highly volatile and uncertain. They depend on a convergence of factors, including natural stream flows, fuel prices, seasonal and daily differences in demand, transmission congestion, competitive supply costs, and market developments in the United States. An appropriate level of trading benefits will continue to be assigned for rate-setting purposes to help maintain low and stable rates for B.C. consumers. A separate entity, the BC Hydro Transmission Corporation, will operate BC Hydro's publicly owned transmission system. This will ensure fair access for all generators and the provision of independent transmission service to maintain and increase B.C.'s trading activity with US wholesale power markets.

PUBLIC OWNERSHIP AND EFFICIENCY

Policy Action #3 (ongoing): Public ownership of BC Hydro's generation, transmission and distribution assets will continue.

A generation of British Columbians before us invested heavily in the hydroelectric network on the Peace and Columbia

Quebec and Low-Cost Hydroelectric Power

In the 1960s, Quebec established a Social Compact requiring province-wide electrification, uniform cost-based power rates, and the use of its hydroelectric resource endowment for the benefit of provincial citizens. This mandate was reinforced in a new energy policy in 1996, and the Quebec government clarified the roles of existing low-cost generation and future competitive electricity supply in legislation passed four years later.

Bill 116 created a "heritage pool" that assures provincial customers up to 165 TWh of annual Hydro-Quebec generation at the fixed rate of 2.79 cents per kWh. This rate, which can be reduced but not increased, is currently the lowest in North America for such a large quantity of power. Beyond the pool limit, the utility's generation arm (Hydro-Quebec Production) can sell at market prices, while its distribution arm (Hydro-Quebec Distribution) must acquire new supply from an open bidding process that includes private power producers and other alternative suppliers.

rivers. Three decades later, that investment is yielding substantial returns. B.C. consumers have electricity that is low-cost, reliable, clean, and renewable. Provincial taxpayers, as ultimate owners of the assets, receive a fair return on the invested capital, with BC Hydro's annual dividend averaging about $350 million over the past five years.

Public ownership is consistent with more competition in electricity markets. Even where markets have been significantly reformed, publicly owned generation coexists with private power. For example, since its electricity reforms in the early 1990s, Norway has increased the share of private generation, but its hydro-based system remains largely in public hands. Organizations such as Hydro-Quebec and the US Bonneville Power Administration continue to recognize the unique value of hydroelectric power in advancing social and environmental goals.

Policy Action #4 (new): BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.

Recently, BC Hydro has been working to outsource services such as customer billing, information technology, human resources, and financial and procurement services. This is part of a series of internal changes designed to make its operations more flexible and cost-effective. As part of the re-regulation of BC Hydro rates (see below), the BC Utilities Commission will be reviewing the Corporation's costs to determine that they are in ratepayers' interests. To help keep rates low, BC Hydro will explore further opportunities to outsource services where cost savings can be achieved and the quality of customer service will be maintained or improved.

RE-REGULATION OF BC HYDRO RATES

Policy Action #5 (new): The BC Utilities Commission will once again regulate BC Hydro rates.

The current rate freeze will end on March 31, 2003 and will not be extended. Rates will again be regulated to cover the projected costs of electricity to consumers. With re-regulation, there will be immediate pressures for rates to rise to cover maintenance expenditures and investment in new generation and transmission. However, any rate changes will be mitigated in several ways. First, the value of low-cost generation will be locked in for ratepayers under the heritage contract and BC Hydro ratepayers will continue to benefit from trade. Second, investment in new power supplies will come from cost-competitive private power development. Third, once new rates have been determined, subsequent rate changes will be set through performance-based regulation, which encourages the sharing of cost savings with ratepayers. In any case, properly regulated rates that reflect actual electricity costs will provide a better signal for new investment, conservation, and energy efficiency over time.

A number of actions in this plan, such as the heritage contract, will require further development before a BC Hydro rate hearing can proceed. The BC Utilities Commission will conduct an inquiry to develop and refine these policy areas prior to the rate hearing. The terms of reference for this policy inquiry will be released in January 2003, and will include a timetable for completion. Following the policy phase, BC Hydro will make a revenue requirements filing with the Commission before the end of 2003/04.

The Province is taking the political interference out of rate-setting

Actions under other strategic objectives that also support low power rates:

#6	The Vancouver Island Generation Project will be reviewed by the BC Utilities Commision to determine if it is the most cost-effective means to reliably meet Island power needs.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

ENERGY FACT

Vancouver Island businesses and residents use one-fifth of BC Hydro's electricity.

SECURE, RELIABLE SUPPLY

Secure, reliable energy for B.C. consumers will be ensured through new power for Vancouver Island, ongoing reliability efforts, the least-cost acquisition of new power, exploration and development of new oil and gas resources, and more efficient regulation by the BC Utilities Commission.

RELIABLE ELECTRICITY AND NATURAL GAS

Policy Action #6 (new): The Vancouver Island Generation Project will be reviewed by the BC Utilities Commission to determine if it is the most cost-effective means to reliably meet Island power needs.

BC Hydro examined two primary options for increasing power capacity to Vancouver Island: additional gas-fired generation on the Island and a new natural gas pipeline, or new submarine transmission from the Mainland. BC Hydro found the second option to be more expensive, requiring transmission upgrades and new generating capacity elsewhere in the province. In June 2002, BC Hydro applied for environmental approval of a 265 MW natural gas-fired plant to be sited at Duke Point in Nanaimo. This project may be developed by either BC Hydro or an IPP. Should BC Hydro undertake this project, a Certificate of Public Convenience and Necessity (CPCN) from the BC Utilities Commission must be obtained.

Policy Action #7 (ongoing): High reliability and energy security will be maintained through well-functioning natural gas markets and coordinated electricity planning.

There are two active natural gas trading hubs, one at Station 2, a delivery point south of Fort St. John on Duke Energy Gas Transmission's system, and the second on the BC/Washington State border, at Sumas. The Sumas trading hub tends to have more volatile prices. A price spike in December 2000 was particularly difficult for large consumers who had opted for spot price contracts. Nonetheless, the government is confident that natural gas markets are functioning properly, and that they will provide the necessary response to any deficiency in supply. Indeed, several proposals are currently under review to increase pipeline capacity, for example, the Duke Energy Mainline expansion, Inland Pacific Connector, and Georgia Straight Crossing projects. Market participants, including neighbouring suppliers in Washington State, are also pursuing north-south strategies to improve the reliability of natural gas supply and reduce price volatility.

In electricity, the Western Electricity Coordinating Council is responsible for comprehensive reliability management in the western grid. Regional transmission organizations, such as RTO West, will facilitate and coordinate planning to remove transmission bottlenecks and increase trade. BC's participation in RTO West, together with our high reliability standards and publicly owned transmission assets, will ensure that provincial consumers have continuing access to reliable electricity.

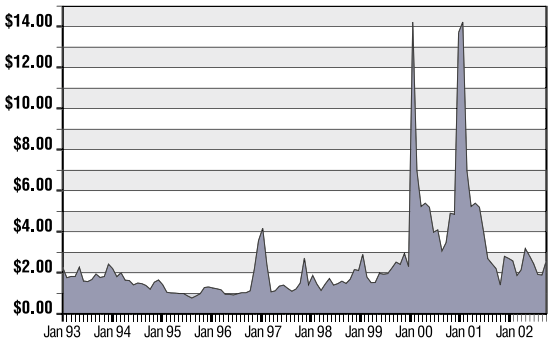
Policy Action #8 (new): BC Hydro distribution will operate as a separate line of business from generation.

The obligation to serve electricity customers will be vested in BC Hydro's distribution line of business. Distribution will acquire energy under the heritage contract from BC Hydro's generation line of business at the price determined by the BC Utilities Commission.

Policy Action #9 (new): Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.

When deciding how to meet a projected power need, BC Hydro's distribution business will compare the costs of all potential resources, including IPP purchases, customer-owned generation, BC Hydro plant efficiency improvements (Resource Smart), conservation and energy efficiency, and firm imports. The distribution arms of other B.C. electric utilities are encouraged to adopt a similar resource acquisition process, if they have not already done so. The BC Utilities Commission will oversee the acquisition process to ensure that least-cost options are chosen consistent with a new clean energy goal (see Environmental Responsibility and No Nuclear Power Sources).

NATURAL GAS PRICES
(US$/MMBtu)



Source: Inside Federal Energy Regulatory Commision Index

NEW OIL AND GAS RESOURCES

Policy Action #10 (ongoing): Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.

The development of BC's large untapped coalbed methane (CBM) resources can benefit both BC consumers and investors (see box). The Ministry of Energy and Mines is implementing a strategy to develop CBM as a clean, environmentally safe energy source that can serve local, domestic and export markets. After a year-long collaboration between government and industry, a new royalty regime was introduced in March 2002 to address CBM's unique development and production challenges. The Oil and Gas Commission is preparing guidelines that will clarify the regulatory requirements for projects. The Ministry has also been working with industry, First Nations, and other stakeholders to provide information on the potential resources, environmental impacts, and economic benefits associated with this new resource opportunity. In addition to CBM, B.C. has other unconventional resources including shale and tight gas as well as the recently reported deposits of methane hydrates off the west coast of Vancouver Island.

Policy Action #11 (new): The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to a develop a provincial position, work with the federal government and move effectively toward development of offshore resources.

Moratoria from both the federal and provincial governments currently prohibit exploration and development of offshore hydrocarbons. The Minister of Energy and Mines appointed a scientific panel headed by Dr. David Strong, which found no scientific basis for a blanket moratorium on the entire BC coast. The panel made a number of recommendations that are now being pursued in partnership with the University of Northern British Columbia.

Before offshore development can proceed, further issues need to be resolved. The provincial and federal governments will have to agree on an overall management regime, including regulatory, royalty, and environmental requirements. The Province will also need to work with coastal communities and First Nations to ensure that benefits accrue to the areas where activity occurs.

STRENGTHENING THE BC UTILITIES COMMISSION

Policy Action #12 (new): The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other distributors, will be strengthened.

With the return to BC Hydro rate regulation, a strong and competent regulator is needed. The BC Utilities Commission has been a Canadian leader in the approval of wholesale and retail access for electricity and gas, the efficient determination

Coalbed Methane: A New Opportunity

CBM is the natural gas found in most coal deposits. It is created through a process by which plant material is converted into coal over millions of years. Under most circumstances, CBM consists of pure methane gas. Commercially produced CBM can be distributed by the existing natural gas pipeline system and used as a heating fuel and alternative transportation fuel.

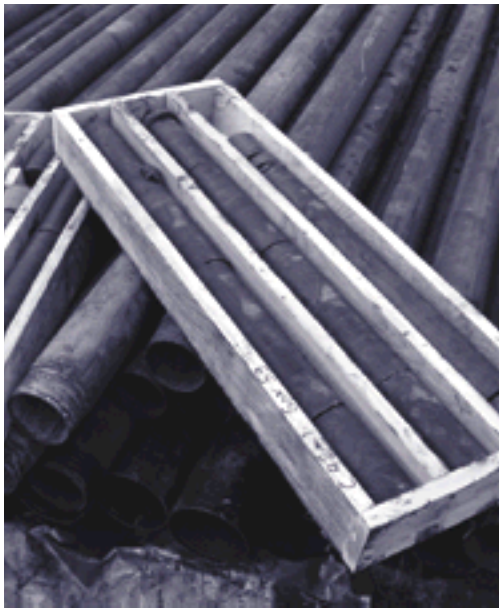
In the 1980s, tax incentives led to the rapid growth of CBM production in the United States. Today, it accounts for more than 7 percent of total annual US natural gas produced. An unprecedented number of CBM projects in BC and Alberta are evaluating gas production characteristics. Nine experimental projects are underway here – 7 in the Northeast and one in the Southeast – and one well has been drilled on Vancouver Island. Commercial production could begin within a few years.

Because coalbed methane is a pure or "sweet" gas, it usually requires little processing before entering the pipeline. Compared to conventional natural gas, CBM development commonly results in large amounts of water being produced prior to and during gas extraction. The production and disposal of water is regulated to minimize impacts on the environment and nearby communities.

ENERGY FACT

In 2001, oil and gas exploration companies drilled three times the number of wells they drilled in 1990

Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.



of utility rates of return, and the adoption of performance-based regulation and alternative dispute resolution. To fulfill its mandate, the Commission will be strengthened by appointing two full-time Commissioners. The Utilities Commission Act will be amended to focus more on performance-based and results-based regulation, including negotiated settlements, and to define effective consumer participation.

MORE PRIVATE SECTOR OPPORTUNITIES

To increase the role of the private sector in energy supply, private power production will be encouraged, access to the transmission system will be improved, oil and gas investment will be supported, and some customers will be able to choose their suppliers.

INVESTMENT IN PRIVATE POWER

Policy Action #13 (new): The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.

The private sector is well positioned for power development, given its ability to find entrepreneurial capital, efficiently build and operate facilities, and take on the associated risk. B.C.'s independent power producers (IPPs) have already demonstrated that they can come forward with cost-effective projects. With BC Hydro's participation limited to efficiency improvements and capacity upgrades at existing facilities, IPPs will be able to serve new domestic needs and explore opportunities in the export market. The intent will be to encourage the private sector to find a variety of innovative and economical ways to satisfy the growing demand for power.

BC Hydro's relative strengths lie in the operation of large-scale hydroelectric generation. While BC Hydro does not plan to invest in the construction of new hydroelectric facilities at the present time, any proposed new BC Hydro hydroelectric facility, such as Peace Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply. Cabinet will then decide whether the project should be developed by BC Hydro or the private sector.

Policy Action #14 (new): Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

New stepped pricing (see Conservation and Efficiency) will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the utility's cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers. Aquila Networks Canada already offers retail access to its industrial customers.

Policy Action #15 (new): The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.

A new publicly owned entity, BC Hydro Transmission Corporation, will be responsible for planning, operating, and managing BC Hydro's transmission system. The transmission assets will continue to be owned by BC Hydro. The corporation will have a separate board of directors and will be regulated by

Actions under other strategic objectives that also support secure, reliable supply:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

the BC Utilities Commission. It will ensure that there is adequate transmission capacity available to reliably serve domestic and export needs, and that all electricity suppliers and buyers have non-discriminatory access to this capacity. The corporation will assess the need for new transmission and will be authorized to direct expansions of the transmission system where required.

Establishing the BC Hydro Transmission Corporation, implemented through legislation as a separate entity, will improve the ability of independent power producers and BC Hydro to participate in regional wholesale markets. Access to these markets is important if we are to attract the new investment required for power development and generate export revenues which help to keep provincial electricity rates low.

Policy Action #16 (new): The BC Utilities Commission will determine the terms and rates for this new transmission entity.

The BC Utilities Commission will review and approve wholesale transmission rates. In an initial rate hearing, the commission will consider issues such as the allocation of costs between generation and transmission, and exit and entry fees for large customers who leave the BC Hydro system (under the new rate structure). Once the initial rates have been determined, future rate changes will also be reviewed and approved by the commission.

SUPPORT FOR OIL AND GAS DEVELOPMENT

Policy Action #17 (ongoing): The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years.

The ministry provides ongoing industry support in the form of information on natural gas resources and the promotion of B.C. investment opportunities outside the province. It regularly reviews resource royalty and tax regimes to maintain our competitive position for attracting energy investment. New royalty regimes were introduced for natural gas in 1998 and coalbed methane in March 2002. Reduced royalties may be considered for other emerging resource opportunities (e.g., shallow and deep gas) and unconventional resources (e.g., shale and tight gas).

The Oil and Gas Commission is further streamlining its one-window approval process for oil and gas development. Under a new general development permit, companies can now apply for a review of their overall plans for the development of an area, rather than having to make separate applications for a number of activities (e.g., roads, wells, pipelines) at different times. Other improvements include a streamlined permitting process for petroleum roads and reduced review times for geophysical, well, and pipeline applications where supported by a professional forester.

Policy Action #18 (ongoing): Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.

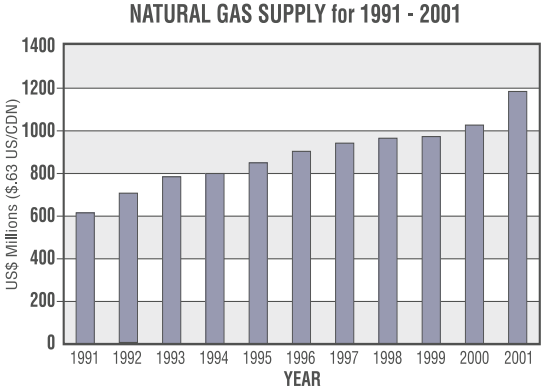
Two pre-tenure plans have been completed for the Muskwa-Kechika Management Area, with oil and gas tenures issued and a successful natural gas well drilled in one of the planning areas. The Ministry of Sustainable Resource Management is expediting the process to deliver the six remaining pre-tenure plans by December 2003. The Ministry of Energy and Mines will increase its involvement in land use planning to ensure that the value of undiscovered oil and natural gas resources is properly recognized, and that access to these resources is not unduly compromised. This will be accomplished by providing better information on oil and gas potential and having a ministry representative on land use planning committees.

In November 1999, $103 million was committed over six years to upgrade existing public roads used by the oil and gas industry in northeastern B.C. Investment to date has already resulted in increased land sales and royalties, summer drilling programs, and private road building off the improved public roads. With legislation passed in spring 2002m the Ministry of Energy and Mines can pursue innovative public-private partnerships (see box) that support the development of a strong and efficient road network for increased oil and natural gas activity.

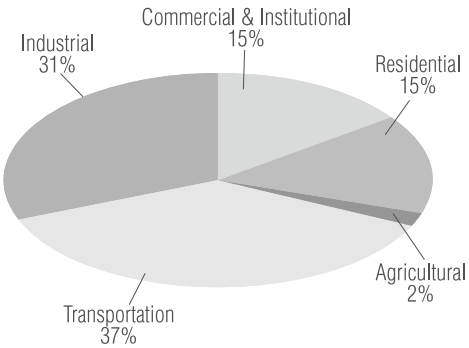
Public Private Partnerships: The Sierra-Yoyo-Desan Road Project

In December 1998, government and industry formed a five-year partnership to upgrade and maintain the Sierra-Yoyo-Desan road northeast of Fort Nelson. This road is part of a network providing access to more than 27,000 square kilometres of oil and gas rich territory that produced about $232 million in royalties and taxes, and $126 million in land sales in 2001. Under the $12.6 million partnership, the costs of improvements are recovered in fees paid by petroleum, seismic, construction and timber companies, while the government contributes to road maintenance costs. The general public has free access to the road.

As a result of the road improvements, drilling activity increased 252% overall, and 400% in the months outside of the traditional winter drilling season (December to April). Funding is needed beyond the partnership term (ending November 2003) to maintain the road and further upgrade it to allow for additional increases in activity levels.



ENERGY CONSUMPTION BY SECTOR



NATURAL GAS SUPPLIER CHOICE FOR SMALL VOLUME CONSUMERS

Policy Action #19 (new): Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.

For three years, natural gas suppliers, ratepayer groups and the BC Utilities Commission have been working to extend direct sales to residential and small commercial customers. New tracking software will allow customer bills to identify from whom natural gas was purchased and what it cost. Although gas brokers and marketers have successfully shown that they can provide a customized array of low-cost services, some jurisdictions (e.g., Ontario and Alberta) have required licensing and bonding to protect consumers from misleading marketing practices.

The Utilities Commission Act will be amended in spring 2003 to allow direct natural gas sales to low-volume customers, and to require the licensing of marketers who serve those customers. The commission will establish the rules, including posting of a security deposit, to obtain a gas marketing licence.

In addition, the requirement for large natural gas customers to file their supply contracts with the commission will be removed, since the high-volume direct sales market is now mature and a high level of regulatory oversight is no longer needed.

ENVIRONMENTAL RESPONSIBILITY AND NO NUCLEAR POWER SOURCES

Environmentally responsible development and use of energy will be ensured through the promotion of cleaner energy sources, measures to increase conservation and energy efficiency, strategies for controlling air emissions and clearer, more efficient environmental regulation.

ALTERNATIVE ENERGY DEVELOPMENT

Policy Action #20 (new): Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from *BC Clean Electricity* over the next 10 years.

BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small/micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and efficiency improvements at existing facilities. This broad definition will allow for the development of a diverse range of cost-effective and environmentally responsible resources across the province.

BC Hydro has already surpassed its voluntary target to meet 10 percent of new energy requirements from clean energy. A goal of 50 percent of new supply between 2002 and 2012 is achievable, given the broader definition of BC Clean electricity. The 50 percent level is expected to push the market for new energy sources. It may raise electricity rates by 0.1 to 0.2 percent per year over the next decade.

The goal will be voluntary so that distributors have the flexibility to acquire electricity at competitive prices. At the

Actions under other strategic objectives that also support more private sector opportunities:

#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#10	Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.
#11	The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to a develop a provincial position, work with the federal government and move effectively toward development of offshore resources.
#12	The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened.
#25	Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.
#26	To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

same time, the BC Utilities Commission will take the goal into account when overseeing the acquisition process for new resources (see Secure, Reliable Supply). The goal will apply equally to the distribution businesses of BC Hydro, Aquila Networks Canada and other investor-owned utilities. They will develop policies (e.g., net metering and interconnection standards) to achieve the goal.

CONSERVATION AND ENERGY EFFICIENCY

Policy Action #21 (new): New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.

The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro's industrial and large commercial customers. As a principle, for stepped rates, the last block of energy consumed should reflect the cost of new supply. This will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively. To keep rates low overall, the stepped rate structure will be revenue-neutral (see box). Time-of-use rates will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods. Both rate structures will benefit British Columbians by deferring the environmental impacts of new power development.

The BC Utilities Commission has approved time-of-use pricing and stepped fixed charges for Aquila Networks Canada customers, and time-of-use pilots for large BC Hydro customers. Given the administrative costs of rate design and the metering investment required for time-of-use rates, these alternative rate structures tend to be less feasible for small customers. Stepped rates will be initially applied to large rate customers. They may be applied, at a later date, to other customer classes.

Policy Action #22 (new): The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.

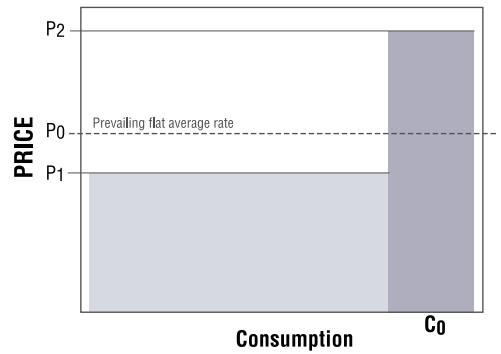
In 1991, B.C. passed an Energy Efficiency Act to set energy performance standards for new appliances and equipment. Minimum performance standards now cover a variety of appliances and equipment, including refrigerators, water heaters, heat pumps, woodstoves, electric motors, and street lighting. There are opportunities to expand the existing regulations to include products such as residential and commercial lighting, natural gas fireplaces, and water-using equipment. Minimum performance levels already established for equipment (e.g., natural gas furnaces) can be upgraded and further harmonized with national and international standards. The Ministry of Energy and Mines will pursue these opportunities with the federal government, electricity and natural gas distributors, standards associations and the equipment industry.

A number of activities are underway to improve building energy efficiency in the province. For example, the BC Buildings Corporation delivers a high performance buildings initiative that provides tools and information for energy efficiency improvements in public buildings (e.g., schools and hospitals). The Greater Vancouver Regional District (GVRD) is developing a Better Buildings Partnership that includes a revolving fund for commercial and institutional energy retrofits. The government will work with Natural Resources Canada, GVRD, energy distributors, builders, developers, and others to strengthen and supplement these efforts.

Policy Action #23 (new): The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

There is a bias in the application of the Utilities Commission Act against conservation and energy efficiency investments, relative to investments in new energy supply. Electricity and natural gas distributors do not earn a return on energy-saving expenditures as they do on new generation and transmission spending. The Province will amend the Act to remove this

STEPPED RATES FOR CONSERVATION AND ENERGY EFFICIENCY



Stepped Rates for Conservation and Energy Efficiency

A revenue-neutral two-step electricity rate charges less for the first block of electricity consumed (P_1), and more for the second block (P_2), relative to the prevailing flat average rate (P_0). At the higher price P_2, the consumer has a greater incentive to cut back on electricity use, or to invest in cost-effective energy efficiency for that portion of consumption. At the existing consumption level C_0, the total cost to the consumer and the total revenue to the distribution company offering the rate are unchanged.

ENERGY FACT

In February 2002, the BC Progress Board ranked B.C. first in Canada in terms of environmental quality.

disincentive, with the goal of encouraging further utility investment in conservation and energy efficiency.

CONTROLLING AIR EMISSIONS

Policy Action #24 (new/ongoing): The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.

The Ministry of Water, Land and Air Protection and the Ministry of Energy and Mines (MEM) are leading the development of a comprehensive climate change plan. MEM already promotes the reinjection of acid gas into existing natural gas wells, to reduce harmful air emissions. Work is underway with other western provinces and the federal government to test new reinjection and cleaner coal technologies, and to define requirements for the capture and storage of carbon dioxide in depleted oil and gas reservoirs and coal seams. Future plans include sponsoring related research at B.C. universities, designing pilot activities for mineral sequestration of CO_2, and examining opportunities for linking coalbed methane development and CO_2 disposal.

It is recognized that the siting of new energy supply operations is a particularly pressing issue for vulnerable airsheds. Certain kinds of supply can result in a net reduction in local air emissions. As part of the commitment to protect threatened airsheds, airshed management plans will be developed in partnership with industry, the federal and local governments, and others to define the steps required to improve air quality.

IMPROVING REGULATION

Policy Action #25 (new/ongoing): Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.

The provincial environmental assessment process has recently been reformed to make it more flexible, streamlined, cost-effective, and tailored to the needs of individual projects. This will include reducing duplication and overlap with federal environmental reviews. Under the reformed provincial process, some projects may by subject to a simpler process, or may be reviewed through other mechanisms. Decisions on how to handle project reviews will be made on a case-by-case basis depending on the project's profile and unique circumstances. In addition, concurrent permitting will allow for the more timely development of energy projects.

Actions under other strategic objectives that also support environmental responsibility:

#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.

The Oil and Gas Commission issues water licences and land tenure applications for the oil and gas sector, including federally regulated facilities. In February 2002, the ajudication of applications for crown land and water for other sectors was merged into an integrated review process administered by Land and Water British Columbia Inc (LWBC). LWBC has prepared guidelines for applicants to clarify the process, and is working to eliminate the backlog in small hydro applications.

The Ministry of Water, Land and Air Protection has begun consultations to revise the Waste Management Act and Regulations governing air emissions and water discharges from facilities. It is anticipated that this 18-month review will result in significant amendments to the legislation and regulations, as well as new and innovative environmental management tools.

Policy Action #26 (new): To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

Coal-fired electricity generation is currently an important source of electricity in other provinces, but not in B.C., despite large resources of cleaner thermal coal. For some industrial consumers, coal became an economically attractive energy source when natural gas prices rose sharply in 2000 and 2001. Further volatility in natural gas prices could lead to increased pressure to use coal as a replacement fuel. The province needs well-defined environmental standards and an efficient regulatory process for evaluating potential coal-fired electricity developments.

Since 1995, B.C. has had interim guidelines in place for emissions of nitrous oxides, sulphur dioxide, metals, and particulates from coal-fired power boilers. These guidelines, which are based on best available control technology, are meant to assist project proponents and help Ministry staff with the environmental assessment and waste permit application processes.

Alberta has established technology-based emission requirements for coal-fired plants. Permit limits are no less stringent than the technology-based limits in the guidelines. However, permit limits may be more stringent if a site specific dispersion model prediction determines that this is required at the particular location to ensure that ambient air quality objectives in the receiving airshed will be met.

On January 1, 2003, the Ministry of Water, Land and Air Protection will adopt emission guidelines for coal-fired power plants that will allow B.C. to compete for investment with neighbouring jurisdictions. Specific dispersion model predictions will determine whether more stringent stack limits are required at any proposed location. To determine if more stringent stack limits are required, proponents will undertake specific dispersion model predictions.

Designing an Effective Portfolio Standard

B.C.'s clean energy goal is a variation on renewable portfolio standards (RPS) that have been adopted in jurisdictions such as Australia, Denmark, the Netherlands, Italy, the United Kingdom, Massachusetts, Nevada, and Texas. These standards require a minimum amount of electricity (usually a percentage of total sales) to be purchased from particular energy types or technologies. Key issues for the design of an RPS are the coverage of clean energy resources and the level of the standard.

Most portfolio standards limit their coverage to small-scale renewable energy sources, although in some cases large hydropower, cogeneration, and energy efficiency measures (e.g., heat pumps) are also included. Maine, for example, allows existing domestic hydroelectricity to be counted towards its current 30% standard. By excluding large hydro but allowing other energy sources such as municipal solid waste and cogeneration, the B.C. goal offers greater regional flexibility in developing environmentally responsible generation.

How big a portfolio standard should be depends essentially on how much more customers are willing to pay for clean energy. Compared to other jurisdictions, the province's lower electricity rates make alternative energy generation less attractive. The fact that many alternative electricity resources are located further away from customer loads, and provide intermittent or seasonal energy, adds to the costs of delivery and reliability relative to conventional generation (e.g., a gas turbine). The level of the clean energy goal must be set so as not to unduly raise electricity rates over time.

This plan has described a series of actions to ensure low electricity rates and public ownership of BC Hydro; secure and reliable energy supply; increased opportunities for the private sector in energy production; and environmentally responsible energy development and no nuclear power sources. These actions will be implemented over the next two years.

The B.C. energy sector is vital to the prosperity of British Columbians.

Demands for energy in B.C. and export markets have supported the development of a diverse, reliable, and economical energy supply system. Our extensive hydroelectric power and natural gas systems benefit British Columbians and export customers alike. New energy supplies are essential if we are to meet the needs of a growing population and economy over the coming years. B.C.'s energy resources, together with our homegrown technology and talent, can continue to ensure energy development and use that are both economical and environmentally responsible. They will help sustain our traditional resource industries and attract and grow an expanding technology sector. Energy has an important role to play not only in revitalizing and developing the provincial economy, but also in supporting the lifestyle and clean environment that makes B.C. a coveted place to live.

This energy plan provides recommendations to build on B.C.'s strengths with opportunities for the continued enrichment of all British Columbians.

The B.C. energy sector is already highly developed. We have abundant energy resources, including natural gas, oil, coal, coalbed methane, hydroelectricity, and alternative energy. We can also do more to reduce energy use through conservation and energy efficiency. New B.C. technologies and expertise, in areas ranging from hydroelectricity to fuel cells, can be harnessed for energy development and export. The actions in this plan statement will build on our existing strength to provide opportunities for increased investment, trade and economic development across the province.

Each of the key players in the energy sector will benefit from the policy.

The 26 policy actions and their benefits for energy consumers, the private sector and the province are summarized in Table 1. In this table, economic opportunities encompass a lower production cost for B.C. industry, jobs and regional economic development. These actions will affect key participants in the energy sector as follows:

Energy consumers. Electricity consumers will be assured low electricity rates through the heritage contract for existing low-cost generation, continued access to trading benefits, efficient private electricity development, and effective regulation to keep rate increases down. New rate structures will allow large power users to save on their energy bills and meet a portion of consumption requirements through energy saving activity, private power purchases or self-generation. Small natural gas consumers will be free to buy directly from natural gas suppliers other than the local distribution company.

Energy distributors. To ensure low electricity rates, BC Hydro and Aquila Networks Canada will acquire new resources on a least-cost basis, with regulatory oversight by the BC Utilities Commission. They will offer new rate structures to large customers, and will pursue a clean energy goal of 50 percent of new power supply over 10 years. Natural gas companies will face competition to supply small as well as large customers. All energy distributors will have their rate increases determined by the BC Utilities Commission using performance-based regulation. A regulatory change will remove the disincentive to conservation and energy efficiency investment.

BC Hydro. BC Hydro will retain ownership of its power assets. To make operations more efficient and transparent, it will continue to reorganize into separate business units for generation, transmission and distribution, and will outsource services where cost savings can be achieved. The mandate of the generation business will be to manage the heritage assets, make efficiency improvements at existing facilities and provide energy and capacity to the domestic market while maximizing trade revenue potential and investment return to the Province. A new separate entity, the BC Hydro Transmission Corporation, will plan, operate and manage the BC Hydro system, with the

transmission assets remaining publicly owned. This change will enable power marketers to continue to benefit from selling into US wholesale markets. The distribution business will have an obligation to serve customers, and will procure power at least cost while maintaining the BC Clean goal. The current rate freeze will be lifted and BC Hydro rates will again be regulated by the BC Utilities Commission.

Independent power producers. IPPs will be responsible for developing new generation in the province. The new BC Hydro Transmission Corporation will provide nondiscriminatory access to the BC Hydro transmission system at rates to be determined by the Utilities Commission. IPPs will be able to sell directly into regional wholesale markets. They will also be able to compete with distributors to serve all or a portion of large consumers' requirements.

Oil, natural gas and coal producers. Land use and pre-tenure plans and northern road upgrades will improve access to resources for oil and gas producers. Royalty restructuring will support new and emerging resource opportunities, such as coalbed methane and unconventional natural gas. The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to a develop a provincial position, work with the federal government and move effectively toward development of the offshore resources. Clear emission standards for coal-fired power plants will provide greater regulatory certainty for electricity development using B.C.'s abundant thermal coal resources. Regulatory streamlining will allow more efficient resource development.

BC Utilities Commission. The BC Utilities Commission will be strengthened and will fulfill its mandate to protect the public interest by reviewing and approving energy rates, reliability standards and other conditions of service. The Utilities Commission Act will be updated to reflect the move to negotiated settlements and performance-based regulation. New rates will be determined for BC Hydro and the BC Hydro Transmission Corporation, as well as new rate structures for large electricity consumers. The commission will also provide regulatory oversight of the least-cost resource acquisition processes of BC Hydro, Aquila Networks Canada and other investor-owned utilities while maintaining the BC Clean goal.

B.C. taxpayers. Taxpayers will continue to receive the benefits from public investment in BC Hydro. New power development by the private sector will protect them from the financial risks of building new generation. Private power production and the development of new energy supplies (e.g., alternative power, coal-fired electricity, coalbed methane, offshore oil and gas) offers additional government revenues to help fund health care and other services.

B.C. communities. Communities will benefit from the increased economic activity from developing new energy supplies and investing in energy efficiency. Local investment will generate jobs and economic spin-offs throughout the province. The clean energy goal, measures to encourage energy saving, and strategies for reducing greenhouse gas and local air emissions will all contribute to environmental improvement in energy-producing communities.

B.C. will be better positioned for further evolution in energy markets. North American energy markets are evolving at a rapid pace. B.C. must be able to respond to these changes if we are to continue realizing the economic benefits they offer. This energy plan will encourage the development of new resources to strengthen and diversify energy supply. The result will be a flexible and robust energy sector that can respond to further market challenges and opportunities as they arise.

Energy for Our Future: A Plan for BC. Some of the actions described in this plan are already underway. Others will require time for careful planning and implementation. A public hearing on BC Hydro rates will be held by the end of 2003/04. The plan will be rolled out over the coming months, with full implementation by December 2004.

Low electricity rates and public ownership of BC Hydro

Secure, reliable supply

More private sector opportunities

Environmental responsibility and no nuclear power sources

TABLE 1: Summary of Policy Actions and Benefits

POLICY ACTIONS			BENEFITS					
			B.C. ENERGY CONSUMERS		PRIVATE SECTOR	THE PROVINCE		
#	ACTION	STATUS	Low Electricity Rates	Secure, Reliable Supply	Investment Opportunities	Taxpayer Benefits	Economic Opportunities	Environmental Responsibility
	GENERAL							
7	Maintain high standards of reliability and energy security	Ongoing		✓				
12	Strengthen structure and mandate of the BC Utilities Commission	New	✓	✓				
	ELECTRICITY							
1	Preserve low-cost generation in heritage contract	New	✓	✓			✓	
2	BC Hydro ratepayers continue to benefit from trade	Ongoing	✓				✓	
3	Maintain public ownership of BC Hydro power assets	Ongoing	✓	✓		✓		
4	Contract out BC Hydro services that save costs for customers	New	✓		✓		✓	
5	BC Utilities Commission again regulates BC Hydro rates	New	✓	✓				
6	BCUC review of Vancouver Island Generation Project	New	✓	✓				
8	BC Hydro distribution operates as a separate business from generation	New	✓	✓	✓		✓	
9	Distributors acquire least-cost resources with BCUC oversight	New	✓	✓	✓		✓	
13	Private sector develops new power, with a limited role for BC Hydro	New	✓	✓	✓	✓	✓	✓
14	Large consumers can choose supplier under new rate structure	New		✓	✓		✓	
15	BC Hydro Transmission Corp. improves access to BC Hydro transmission	New	✓	✓	✓	✓	✓	
16	BCUC determines terms and rates for BC Hydro Transmission Corporation	New	✓	✓				

Continued

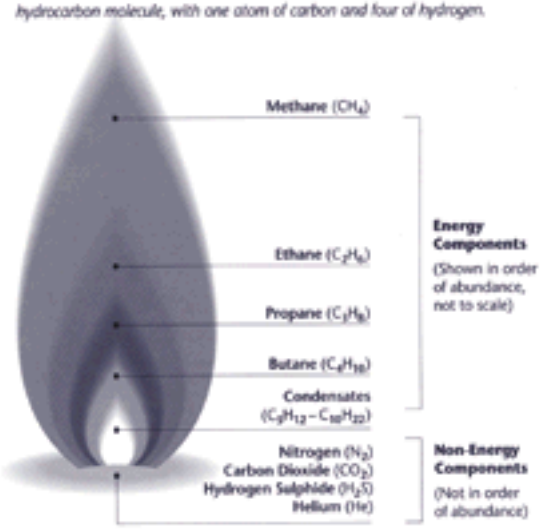
POLICY ACTIONS

			BENEFITS					
			B.C. ENERGY CONSUMERS		PRIVATE SECTOR	THE PROVINCE		
#	ACTION	STATUS	Low Electricity Rates	Secure, Reliable Supply	Investment Opportunities	Taxpayer Benefits	Economic Opportunities	Environmental Responsibility
	FOSSIL FUELS							
10	Policies to encourage coalbed methane development	Ongoing/ New		✓	✓	✓	✓	
11	New offshore oil and gas team	New		✓	✓	✓	✓	
17	Ministry of Energy and Mines supports natural gas investment	Ongoing		✓	✓	✓	✓	
18	Policies to improve access to oil and gas resources	Ongoing		✓	✓	✓	✓	
19	Natural gas marketers can make direct sales to small customers	New		✓	✓			
26	Final emission standards for coal-fired power plants in B.C.	New		✓	✓	✓	✓	
	BC CLEAN ENERGY							
20	Voluntary goal for 50% of new electricity from clean resources	New		✓	✓		✓	✓
21	New rate structures to encourage conservation and energy efficiency	New	✓	✓	✓		✓	✓
22	Update Energy Efficiency Act and improve efficiency in buildings	New		✓	✓		✓	✓
23	Remove regulatory disincentive to utility investment in energy efficiency	New	✓	✓			✓	✓
24	Strategies to manage air emissions	Ongoing/ New						✓
25	Streamlining of provincial regulatory processes	Ongoing/ New	✓	✓	✓		✓	✓

GLOSSARY

Common components of unprocessed natural gas

Natural gas is mostly methane. Methane (CH_4) is the simplest hydrocarbon molecule, with one atom of carbon and four of hydrogen.



Alternate Dispute Resolution. Processes that are alternative or complementary to traditional regulatory process such as technical workshops, issues meetings, discussion groups and negotiated settlements. Regulatory participants resolve issues outside the formal quasi-judiciary hearing process saving time and regulatory costs.

Aquila Networks Canada. With its head office in Calgary, Alberta, Aquila operates electricity distribution system in Southern and Central Alberta and provides generation, transmission and distribution services in South Central British Columbia (Kootenays and Okanagan) to 135,000 customers. Aquila, previously Utilicorp, purchased West Kootenay Power and assets from Teck Cominco.

Biomass energy. Energy derived from organic matter, such as wood residue, agricultural waste, and municipal solid waste.

Capacity. The maximum power that a generating unit, generating station, or other electrical apparatus can supply, usually expressed in megawatts.

Coal Seam. A mass of coal, occurring naturally at a particular location, that can be commercially mined.

Cogeneration. The combined production of electricity and useful heat, used for industrial, commercial, heating, or cooling purposes.

Combined cycle gas turbine. A power plant that uses the waste heat from one or more gas turbines to produce steam for conventional steam turbines, resulting in higher fuel efficiency.

Distribution. The delivery of energy to retail consumers.

Distribution system. The facilities and equipment dedicated to delivering electricity, gas, steam or water to retail customers.

Dividend. An annual payment by BC Hydro to the Province of British Columbia as its one shareholder.

Economies of scale. Characteristic of an industry where long-run average costs decline with volume of production.

Electricity. A manufactured form of energy, as opposed to naturally occurring energy resources, such as coal, oil, or natural gas. On a large scale, electricity is produced by rotating machines (generators) that operate on the principle that an electric current is generated whenever a current moves through a magnetic field.

Emission. A discharge into the air, land, or water from an industrial process, transportation vehicle, household activity, or other source.

Energy. Defined by physicists as the capacity for doing work. Energy can be produced from water, coal, natural gas, biomass and other sources.

Fuel cell. An electrochemical device that continuously converts the chemical energy of a fuel (e.g., hydrogen) and an oxidant into electric energy. Fuels cells can used to power vehicles or to generate electricity in stationary applications.

Generator. An entity that owns and operates an electricity generating plant.

Geothermal energy. Energy extracted from the earth usually in the form of steam that can be used for ground source heat pumps, water heating, or electricity generation.

Gigawatt-hour (GWh). One million kilowatt-hours.

Greenhouse gas emissions. Emissions of a greenhouse gas, such as carbon dioxide, methane, or nitrous oxide, which contribute to trapping of reradiated heat in the earth's atmosphere and warming of the planet's surface.

Grid. A network of electric power lines and connections.

Joule. An international unit of energy.

Kilowatt-hour (kWh). The amount of electrical energy produced or consumed by a one-kilowatt unit for one hour (1,000 watt hours). In B.C. the average annual residential use is about 10,000 kWh.

Landfill gas energy. Electricity produced by collecting and burning methane gas at landfill sites.

Large hydro. A hydroelectric power plant greater than 50 MW in size.

Load. The amount of electric power or energy consumed by a particular customer or group of customers.

Megawatt (MW). 1,000 kilowatts or one million watts.

Micro hydro. Hydroelectric generator with a capacity of less than 2 MW.

Municipal solid waste energy. Electricity produced by burning garbage in a boiler for steam generation.

Photovoltaic energy. Electricity produced directly from sunlight using semiconductors built into solar panels or roofing materials.

Peak demand. The maximum load consumed by a customer, group of customers, or system in a stated period of time, such as a month or year.

Power. The rate at which electric energy is delivered, measured in watts, kilowatts, megawatts, etc.

Power system. The interconnected system of facilities and equipment used by an electric utility to supply electricity to its customers. The system includes generating stations, transformers, switching stations, transmission lines, substations, distribution lines, and circuits to the customer's premises.

Renewable resources. Sources of energy that are inherently self-renewing, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from municipal waste.

Small hydro. Run-of-river hydroelectric power plants greater than 2 MW and less than 50 MW in size. Run-of-river means that the streamflow passing through the powerhouse is basically the same as the natural streamflow, implying that there is no (or minimal) storage reservoir.

Solar energy. The radiant energy of the sun that can be converted into other forms of energy, such as heat (e.g., for water heating) or electricity.

Stepped rates. Rate structure where the unit price rises with consumption.

Terrawatt-hour (TWh). One thousand gigawatt-hours.

Thermal coal. Coal used primarily to generate heat, as opposed to metallurgical coal which is converted to coke for use in steel production.

Thermal power plant. A facility that burns fossil fuels (oil, coal, or natural gas) or uses nuclear energy to generate electricity.

Tidal energy. Electricity produced by harnessing the natural rise and fall of the tide in an estuary or bay of the ocean.

Time-of-use rates. The pricing of electricity based on its estimated cost during a particular time period.

Transmission. The transfer of electricity over power lines and related equipment to the point of transformation for distribution to retail consumers.

Transmission system. The power lines and other facilities and equipment of a power system that deliver electricity from generating facilities to the distribution system.

Water licence. A regulatory permit, issued by Land and Water BC, that provides for the use of a specific quantity of a provincial water resource and authority to construct associated works, such as power facilities.

Water rental. A royalty collected by the Province for the use of water.

Wave energy. Electricity produced by harnessing the natural rise and fall of waves in the ocean.

Wind energy. Electricity produced from a system of airfoils or blades that spin a drive shaft to capture the kinetic energy of the wind.

Wood residue energy. Electricity produced by burning the residues from the forest product sector in a boiler for steam generation.

APPENDIX 1: Comparison of Energy Policy Task Force Recommendations with Energy for Our Future: A Plan for BC

TASK FORCE RECOMMENDATION	ENERGY PLAN ACTION	COMMENT
CONSERVATION, EFFICIENCY AND ALTERNATIVE ENERGY		
4.01 Use a portion of the endowment dividend to establish a foundation that supports comprehensive research and development in conservation, efficiency and alternative energy.		*No move to market prices means there is no endowment dividend to fund a foundation.*
4.02 Set portfolio standards for renewable energy; these standards would apply to electricity distribution companies.	**Policy Action #20** Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.	*The energy plan builds on the task force's recommendation by broadening the definition for a portfolio standard and increasing the percentage from 30 percent to 50 percent.*
4.03 Adopt time-of-use pricing and net metering.	**Policy Action #21** New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.	*The energy plan provides a framework to pursue new rate options for conservation and energy efficiency.*
4.04 Rewrite the Energy Efficiency Act and Regulations.	**Policy Action #22** The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments, and others to improve energy efficiency in new and existing buildings.	*The energy plan adopts the task force's recommendation.*
4.05 Develop a wind project with private-sector expertise using federal funding as announced in the federal budget of December 2001.	**Policy Action #13** The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.	*The energy plan provides the private sector with the framework to pursue projects.*
N/A	**Policy Action #23** The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.	*The energy plan provides regulated distributors with the tools to pursue energy conservation and efficiency.*
ELECTRICITY		
5.01 Develop a wholesale electricity market based on open access to the electricity transmission system. The development of this market must be consistent with market developments in Alberta and the US Pacific Northwest.	**Policy Action #1** A legislated heritage contract will preserve the benefits of BC Hydro's existing generation. **Policy Action #14** Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor. **Policy Action #15** The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.	*While the task force recommended the development of a wholesale electricity market in B.C., the energy plan builds on two themes: low electricity rates and high reliability and security. Low electricity rates will be assured through a legislated heritage contract. A robust market for new supply will be created providing market discipline and opportunities.*
5.02 Establish an independent transmission entity as a Crown corporation clearly separate from all generators, distribution utilities and retailers. All transmission in the province needs to be coordinated by that entity. The entity would be regulated and would: • manage transmission assets; • ensure reliability and security of the system; • administer a wholesale market; and • schedule and balance the transmission system. The establishment of an independent transmission entity would necessitate the restructuring of BC Hydro.	**Policy Action #15** The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets. **Policy Action #16** The BC Utilities Commission will determine the terms and rates for this new transmission entity.	*The energy plan follows the task force's recommendation with the exception that BC Hydro Transmission Corporation will not own the transmission assets. The transmission assets will remain with BC Hydro.*

Continued

ELECTRICITY		
5.03 Restructure BC Hydro. A new Crown corporation responsible solely for generation from the endowment assets and Burrard Thermal needs to be established. In addition, four separate regional distribution utilities need to be established. Non-core assets need to be handled in a separate entity.	**Policy Action #8** BC Hydro's distribution will operate as a separate line of business from generation.	*The energy plan does not support the creation of separate generation and distribution Crowns. Instead, lines of business for generation and distribution will be created to pursue efficiencies and complement the heritage contract noted in Policy Action #1.*
5.04 Establish Crown-owned entities on a commercial basis to resemble comparable, non-government-owned commercial enterprises.		*The energy plan follows the task force's recommendation. BC Hydro is already structured in this manner. This plan does not create numerous Crowns.*
5.05 Encourage private-sector investment in additional electricity generation in the province. This generation needs to be for both domestic and export markets.	**Policy Action #13** The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.	*The energy plan adopts the task force's recommendation by clarifying that the private sector will develop new electricity generation.*
5.06 Recognize Burrard Thermal as integral to British Columbia's electrical system. Burrard Thermal can be upgraded or replaced, the latter requiring lead time and significant financial resources.		*The Province will establish a Committee of Members of the Legislative Assembly to review Burrard Thermal operations and make recommendations on phasing out the existing facilities.*
5.07 Recognize Williston Reservoir's direct and valuable role in supporting electricity generation on the Peace River. The current water license for the Williston Reservoir should be respected.		*A water use plan is being developed for the Peace River system and will be brought to Cabinet for final approval. WUP is a collaborative process to change the operations of hydroelectric facilities that reflect contemporary values and scientific research.*
5.08 Establish 10-year transitional arrangements for the market pricing of generation from the Columbia and Peace River dams, referred to as the endowment, and ensure all customers receive a fair share of the endowment through a rebate. The remaining rebate is to be government revenue with a portion directed to the Foundation on Conservation, Efficiency and Alternative Energy. The Province also needs to take the following complementary policy action: • remove the Provincial Sales Tax on energy inputs for industry, a tax policy unique to British Columbia; • provide accelerated write-offs for investment in energy-saving technology; and • provide rate design incentives to promote energy efficiency by all consumers.	**Policy Action #1** A legislated heritage contract will preserve the benefits of BC Hydro's existing generation. **Policy Action#2** BC Hydro ratepayers will continue to benefit from electricity trade. **Policy Action #21** New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.	*Similar to the task force's recommendation, the energy plan has a 10-year heritage contract. However, the price will be based upon costs of production rather than set by market prices. Further, BC Hydro ratepayers will continue to benefit from electricity trade.* *The Province has eliminated the social services tax for production machinery and equipment. Further changes may be reviewed as part of the annual budget process.* *The energy plan adopts part of the task force's recommendation. Starting with large electricity consumers, a stepped rate will provide an incentive for conservation and energy efficiency. These consumers will also be able to choose a supplier other than the local distributor. Developing a similar program for other rate classes may be more complex, however, some elements may be pursued in the future.*
5.09 Eliminate the electricity rate freeze on January 1, 2003, or sooner, and institute at least a three per cent per annum rate increase for three years to provide funding for electricity infrastructure upgrades and expansion, cost of service and the foundation.	**Policy Action #5** The BC Utilities Commission will once again regulate BC Hydro rates.	*The energy plan does not adopt the task force's recommendation to prescribe a rate increase. Rather, the BC Utilities Commission will review and approve the appropriate rates.*
5.10 Ensure the move to market pricing is fully coordinated with other major policy changes underway. This is particularly important in the forest sector.		*There is no move to market pricing.*
5.11 Ensure distribution companies send strong price signals to consumers by reflecting full market prices in electricity bills.	**Policy Action #21** New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.	*The energy plan partially adopts the task force's recommendation. Starting with large electricity consumers, a stepped rate will provide an incentive for conservation and energy efficiency.*

Continued

ELECTRICITY		
N/A	**Policy Action #3** Public ownership of BC Hydro's generation, transmission and distribution assets will continue.	
N/A	**Policy Action #4** BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.	
N/A	**Policy Action #6:** The Vancouver Island Generation Project will be reviewed by the BC Utilities Corporation to determine if it is the most cost-effective means to reliably meet Island power needs.	
N/A	**Policy Action #9 :** Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.	
OIL AND NATURAL GAS		
6.01 Support and encourage industry to establish one or more natural gas storage facilities in or near the Lower Mainland, possibly including Vancouver Island, to serve British Columbia markets. The storage facility must be accessible to all parties selling natural gas directly to consumers and should be regulated by the BC Utilities Commission.	**Policy Action #7** High reliability and energy security will be maintained through well-functioning natural gas markets and coordinated electricity planning.	*The moratorium on drilling for underground storage will remain. The Province is confident that market participants will develop the appropriate infrastructure and price risk mitigation measures.*
6.02 Through clear, certain and proactive planning and regulation, support, encourage and facilitate timely pipeline expansion. To ensure British Columbia 's natural gas transmission system has adequate capacity to meet demand, the Task Force also recommends the following: • sound and independent supply/demand forecasts to assist regulators and the market; • investment returns that are competitive in the North American market; and • establish a clear process for the BC Utilities Commission to ensure that adequate gas supplies and transmission capacity are reserved for the domestic market to ensure these consumers have access to natural gas at reasonable, stable rates.	**Policy Action #7** High reliability and energy security will be maintained through well-functioning natural gas markets and coordinated electricity planning. **Policy Action #12** The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened. **Policy Action #17** The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years.	*The energy plan adopts most of the components of this recommendation. The Province is confident that market participants will develop the appropriate infrastructure and price risk mitigation measures.* *With a strengthened and focussed BC Utilities Commission, regulatory oversight will be in place ensuring that consumers have access to natural gas at reasonable, stable rates.*
6.03 Promote road infrastructure, specifically for oil and gas. In setting road priorities, consideration should be given to the economic benefits of resource development. Tools to help develop the infrastructure include innovative public-private partnerships and fiscal measures.	**Policy Action #18** Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.	*The energy plan adopts the task force's recommendation.*
6.04 Expedite the development of pre-tenure plans in special management areas so that resource development, as envisioned in the land use planning process, can occur in a timely manner. Land-use priorities and conditions of access should be defined whether in special management areas, which require pre-tenure plans, or elsewhere.	**Policy Action #18** Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.	*The energy plan adopts the task force's recommendation.*

Continued

OIL AND NATURAL GAS		
6.05 Investigate appropriate measures for petroleum and natural gas tenure that allow for large-scale regional exploration within Interior basins.	**Policy Action #17** The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years. **Policy Action #10** Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic development.	*The energy plan adopts the task force's recommendation.*
6.06 Undertake geoscience studies aimed at enhancing opportunities in underexplored petroleum regions, such as the Interior basins, and identify underexplored or new petroleum resources for development in established regions within Northeast British Columbia.	**Policy Action #17** The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years.	*The Ministry of Energy and Mines adopts the task force's recommendation and will undertake geoscience studies.*
6.07 Develop royalty regimes for new resource opportunities such as tight gas and Interior basins.	**Policy Action #17** The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years. **Policy Action #10** Development of coalbed methane and other unconventional resources development will be encouraged to provide a new source of energy supply and opportunities for regional economic development.	*As part of the Province's commitment to provide support for continued industry investment in natural gas production, new royalty regimes will be explored.*
6.08 Create a system of royalty credits to encourage investment in high-cost and high-risk new resources.	**Policy Action #17** The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years. **Policy Action #10** Development of coalbed methane and other unconventional resources development will be encouraged to provide a new source of energy supply and opportunities for regional economic development.	*A new coalbed methane royalty is already in place. As part of the Province's commitment to provide support for continued industry investment in natural gas production, new royalty regimes for conventional and unconventional resources are being explored.*
6.09 Insist that the federal government lives up to its commitment under the Northern Pipeline Act to consult with the province and that the two jurisdictions work to facilitate passage of the pipeline through British Columbia to maximize benefits for the people of the province.		*The Province is confident that market participants will develop the appropriate infrastructure. The Province will work with other levels of government and industry for the benefit of the province.*
6.10 Establish flaring standards for both test flaring and ongoing flaring for operational purposes.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.	*The Oil and Gas Commission and the Ministry of Water, Land and Air Protection are in discussions on transferring the responsibility to the Oil and Gas Commission under the Oil and Gas Waste regulation.*
6.11 Promote acid-gas re-injection as the preferred method for handling waste-gas production by developing appropriate regulatory and fiscal regimes to ensure this becomes the method of choice for the industry.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.	*B.C.'s strategies to manage greenhouse gas and other emissions will look at numerous alternatives, including acid-gas re-injection.*
6.12 Evaluate the potential and technical feasibility for large-scale greenhouse-gas (carbon dioxide)sequestration or subsurface waste-gas disposal in regions likely to require these technologies.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.	*B.C.'s strategies to manage greenhouse gas and other emissions will look at numerous alternatives, including sequestration.*
6.13 Insist that the federal government engage in serious discussions on treaty-related issues.		*The Province is already engaged with the federal government in discussions on treaty-related issues.*
6.14 Work with industry to find creative means to engage First Nations in the development of energy in the province.		*The Province is already working with industry to find creative means to engage First Nations in the development of energy in the province.*

Continued

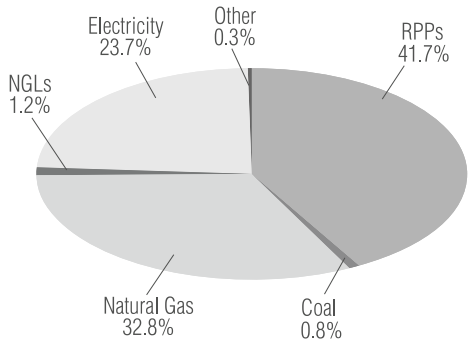
OIL AND NATURAL GAS		
6.15 Support and encourage increased customer choice of provider and offerings for all natural gas customers and, particularly, residential and small commercial customers.	**Policy Action #19** Natural gas marketers will be allowed to sell directly to small customers, and will be licensed to provide consumer protection.	*The energy plan adopts the task force's recommendation.*
6.16 Eliminate the requirement for Energy Removal Certificates in order to streamline the regulatory approval process and avoid duplication of National Energy Board functions.		*Energy Removal Certificates will be eliminated as part of government's New Era commitment to reduce unnecessary red tape and regulation by one third within three years.*
N/A	**Policy Action #11** The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to a develop a provincial position, work with the federal government and move effectively toward development of the offshore resources.	*The energy plan addresses offshore oil and gas exploration and development. The task force concluded that this was not part of it's terms of reference.*
COAL		
7.01 Review best practices, including the application of new coal technology to meet environmental standards and encourage pilot projects by industry.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds. **Policy Action #26** To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.	*The energy plan adopts the task force's recommendation regarding emission guidelines for coal-fired power plants.*
7.02 Finalize emission guidelines for coal generating plants with stakeholders as soon as possible. As any provincial guideline may be superseded by federal requirements, relevant inter-governmental discussions need to be undertaken.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds. **Policy Action #26** To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.	*The energy plan adopts the task force's recommendation.*
7.03 Develop guidelines on boiler emission standards.	**Policy Action #24** The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.	*The energy plan adopts the task force's recommendation.* *The Ministry of Water, Land and Air Protection has launched a broad review of the 20-year-old Waste Management Act. The review process will take approximately 18 months to complete.*
7.04 Ensure that applications for permits are dealt with in a timely manner and that review processes are transparent and efficient. Impose timelines for the permitting process and review public consultation and appeal provisions to ensure that the public interest is adequately protected.	**Policy Action #25** Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.	*The Ministry of Water, Land and Air Protection has launched a broad review of the 20-year-old Waste Management Act. The review process will take approximately 18 months to complete. A reformed Environmental Assessment process encourages concurrent permitting.*
7.05 Review current environmental assessment processes to ensure coal is treated consistently with other energy sources.	**Policy Action #25** Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.	*A reformed environmental assessment legislation was introduced in the spring 2002 session of the Legislature and will be brought into force by the end of 2002.*
REGULATION		
8.01 Strengthen the capacity of the Ministry of Energy and Mines to play the lead role in energy policy formulation and implementation in the province.		*The ministry's service plan includes performance measures to implement the energy policy.*

Continued

REGULATION		
8.02 Ensure the Ministry of Sustainable Resource Management makes energy a priority in its pre-tenure planning activity.	**Policy Action #18** Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.	*The Ministry of Sustainable Resource Management recently approved the Besa-Prophet pre-tenure plan for the exploration of natural gas deposits estimated to have a value of $2 billion.*
8.03 Ensure the Ministry of Water, Land and Air Protection provides clear standards on energy emissions from all sources.	**Policy Action #25** Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined. **Policy Action #26** To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.	*The Ministry of Water, Land and Air Protection has launched a broad review of the 20-year-old Waste Management Act.* *The review process, which will take approximately 18 months to complete.* *The Ministry of Water, Land and Air Protection will adopt guidelines for coal-fired power plants by January 1, 2003.*
8.04 Strengthen the BC Utilities Commission, a key regulatory agency for energy in the province. This requires significant changes to regulatory practice, with a much greater reliance on a results- based and performance-based regulatory framework. A complete rewrite of the BC Utilities Commission Act is required.	**The Policy Action #12** The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened. **Policy Action #5** The BC Utilities Commission will once again regulate BC Hydro rates.	*The energy plan adopts the task force's recommendation. The Utilities Commission Act will be updated and amended as needed to implement the plan.*
8.05 Strengthen the B.C. Oil and Gas Commission and use it as a model for developing a single-window-permitting agency for energy.		*The B.C. Oil and Gas Commission's service plan has identified a number of initiatives to develop a single-window-permitting agency for 95% of the oil and natural gas sectors permitting requirements.*
8.06 Strengthen the BC Environmental Assessment Office and review process. This requires greater results-based practice. It also requires greater harmonization of process with the federal government and this should be accomplished by improving the Canada-British Columbia Agreement for Environment Assessment Cooperation that is currently under negotiation.	**Policy Action #25** Provincial processes for environmental assessment, water licensing, and waste permitting are being streamlined.	*Reformed environmental assessment legislation was introduced in the spring 2002 session of the Legislature and will be promulgated by the end of 2002.*
8.07 Resolve the difficulties investors are having with the Department of Fisheries and Oceans. This will require joint federal/provincial action at the highest levels.		*The B.C. Oil and Gas Commission has developed a strategy to establish a close working relationship with the Department of Fisheries and Oceans.*
8.08 Provide provincial standards for air emissions and thereby avoid duplication and confusion at the local level.	**Policy Action #24** Provincial processes for environmental assessment, water licensing, and waste permitting are being streamlined.	*The Ministry of Water, Land and Air Protection has launched a broad review of the 20-year-old Waste Management Act. The review process, which will take approximately 18 months to complete.*
8.09 Encourage regulators to undertake greater public dialogue and debate with stakeholders and consumers, recognizing that education is the best means to facilitate energy conservation and consumer choice.	**The Policy Action #12** The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened.	*The energy plan adopts the task force's recommendation.*

APPENDIX 2: B.C. Energy Snapshot

ENERGY CONSUMPTION BY FUEL - 2000



GEOGRAPHIC CONTEXT

The majority of B.C.'s current energy supplies are located in the Northeast and Southeast. Oil and natural gas production presently comes from a portion of the Western Canada Sedimentary Basin that extends into northeastern B.C. There are unexplored basins in the Interior and Northwest, on Vancouver Island, and offshore. Recently, very large unproven natural gas reserves, methane hydrates, were reported off western Vancouver Island.

Hydroelectric resources are concentrated on the Peace River in northeastern B.C. and the Columbia River in the southern Interior. Other hydroelectric and thermal power plants are located in the Lower Mainland and on Vancouver Island and the Mid-coast. Some potential alternative energy resources are more focused in coastal areas (e.g., tidal and wind), while others, such as small hydro and wood residue, are scattered throughout B.C.

The province's richest coal deposits are found in the Rocky Mountains in its extreme southeast corner. Additional production occurs in the Northeast and on Vancouver Island, with a promising coalfield (Hat Creek) in central B.C. Coalbed methane deposits have been identified in the Northeast, Southeast, Interior and on Vancouver Island.

Many of our resources are located far from provincial demand centres and export markets. This means long distances over rugged terrain for high-voltage power lines, oil and gas pipelines and rail shipments of coal.

B.C. SUPPLY

B.C. is a major producer of coal, natural gas, hydroelectricity, and oil. While electricity represents approximately 38 percent of the value of the energy sector, it makes up only 11 percent of total primary energy production. Most (80 percent) of the energy produced comes from coal and natural gas, due to B.C.'s endowment of these resources.

An extensive energy production network comprises more than 100 power plants, over 3,700 producing oil and gas wells, 29 gas processing plants, two petroleum refineries, and eight coal mines. There are 18,000 kilometres of power transmission lines, 300 substations, and 80,000 hectares of right-of-way involved in bringing B.C. electricity to market. Approximately 24,000 km of gas-gathering and transmission lines connect natural gas producers and provincial consumers. Another 2,500 km of pipelines carry oil and natural gas liquids to refining facilities within and outside the province.

B.C. CONSUMPTION

Refined petroleum products (RPPs), such as gasoline, diesel, and heating oil, account for the largest share (42%) of B.C. energy consumption, followed by natural gas and electricity. Most of these RPPs are used in transportation, which makes up 37 percent of total energy consumption and is one of the fastest growing consuming sectors. The industrial sector, on the other hand, accounts for the largest share of natural gas (44%) and electricity (49%) consumed, reflecting the energy intensity of BC industry. Although coal represents about 46 percent of primary energy produced, very little of that production is consumed in BC.

TRADE AND CONNECTIONS

B.C. exports energy to markets in Canada, the US, Asia, Europe, and Central and South America. Virtually all coal produced is destined for outside markets, while about 55 percent of natural gas is exported. Although BC Hydro is generally in demand/supply balance, it becomes a net exporter of electricity during high water inflow years. A net energy exporter overall, B.C also imports refined petroleum products and, at times, electricity as part of our trading activities.

The Duke Energy natural gas pipeline connects with the US Pacific Northwest at Sumas, Washington. Among other facilities, the Alliance Pipeline delivers natural gas to the US Midwest and the Southern Crossing Pipeline brings Alberta gas to the Interior. BC Hydro's transmission interconnections with the US provide a transfer capacity of 1,230 to 3,150 MW south and 2,000 MW north. The Alberta links can deliver 400 to 800 MW east and up to 700 MW west.

B.C. utilities participate in US and Alberta wholesale power markets. They do so to take advantage of lower cost electricity, augment their generation during low water inflow years, and sell any surplus energy. BC Hydro has developed an active trading business in these markets by using its flexible hydroelectric plants and an ability to time water releases from reservoirs. By reducing electricity production from dams and importing electricity during low price periods, it can increase production and export during high price periods, while still meeting domestic needs.

INDUSTRY STRUCTURE

BC Hydro, a provincial Crown corporation, owns and operates 80 percent of BC's 14,000 MW of dependable generating capacity. It accounts for more than 90 percent of annual electricity production. The balance is divided among Columbia Power Corporation, Aquila Networks Canada, Alcan, Teck Cominco Limited, self-generators, and independent power producers. Another eight municipal utilities purchase from Aquila Networks Canada and BC Hydro and distribute power in their local areas. Other investor-owned utilities include Hemlock Valley Electrical Services, Princeton Light and Power, Yoho Power and Yukon Electrical Company.

Private ownership characterizes fossil fuel industries. About 200 oil and gas companies and about half a dozen of coal companies presently operate in the province. Duke Energy Corporation (formerly Westcoast Energy Inc.) owns and operates the major natural gas pipeline from the Northeast to Vancouver. Three distribution utilities - BC Gas, Centra Gas and Pacific Northern Gas - and various gas marketers and brokers deliver natural gas to provincial consumers.

REGULATION

The BC Utilities Commission regulates energy utilities and reviews and approves rates and new facilities. BC Hydro was effectively taken out of BC Utilities Commission regulations as a result of the rate freeze in 1996 and ministerial exemptions of BC Hydro's projects.

Provincial and federal environmental assessment processes are used to review major energy development projects. The National Energy Board (NEB) regulates energy exports, while the Department of Fisheries and Oceans has jurisdiction over fish and fish habitat in the ocean and some inland waters. The B.C. Oil and Gas Commission regulates all oil and gas activities, including exploration and development, production, processing and storage.

Energy policy is the responsibility of the Ministry of Energy and Mines, which also has a role in government's direction to BC Hydro. The Ministry of Water, Land and Air Protection sets requirements for water quality, waste management (including air emissions) and wildlife, while the Ministry of Sustainable Resource Management oversees land and water use management and pre-tenure planning. The Greater Vancouver Regional District also has delegated authority for air emissions permitting and other environmental matters. In addition, local governments influence the siting of energy facilities through official community plans and zoning bylaws.

PRICING

For all energy production other than electricity, prices are determined in regional (natural gas) or international (oil and coal) commodity markets. The NEB regulates rates for interprovincial and international pipelines. Instead of traditional cost-of-service regulation, it now encourages the use of negotiated settlements among the parties involved.

The BC Utilities Commission regulates rates for natural gas distribution and electricity to ensure that they are just and reasonable and do not discriminate between customers. Regulated utility rates blend the cost of new with existing energy supplies. Most rates are flat, charging the same price per unit of energy no matter how much consumers use. They are also postage stamp, so that the price does not vary from one location to another.

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BRITISH COLUMBIA

Acquisition Processes Selected
Puget Sound Energy Request for Proposals *From All Generation Sources* Date issued: February 3, 2004
Xcel Energy - Public Service Company of Colorado Request for Proposals *Dispatchable Resources - All Source Solicitation* Date issued: February 2005
Xcel Energy - Public Service Company of Colorado Request for Proposals *Non-Dispatchable Resources - All Source Solicitation* Date issued: February 2005
Hydro Quebec Call for Tenders Document A/O 2003-01 *Annual Firm Capacity for a total of 100 MW and associated energy - Electricity generated using biomass* Date issued: April 15, 2003
PacifiCorp Request for Proposals (RFP 2003-B) *Renewable Electric Resources* Date issued: February 5, 2004
Hydro Quebec Call for Tenders Document A/O 2004-02 *Electricity generated by cogeneration - Annual Firm Capacity for a Total of 350 MW and associated energy* Date issued: October 6, 2004
Nova Scotia Power - An Emera Company Request for Proposals - RFP #27826 *For 100 GWh Renewable Energy* Date Issued: October 29, 2004
Ontario Ministry of Energy 2005 Draft Request for Proposals *Up to 1000 MW of Renewable Energy Supply from Renewable Generating Facilities with a Contract Capacity Between 20 MW and 200 MW* Date issued: April 22, 2005
Ontario Ministry of Energy 2004 Request for Proposals *2500 MW of New Clean Generation and Demand-Side Projects* Issued: September 13, 2004
Ontario Ministry of Energy 2004 Request for Proposals *300 MW of Renewable Energy Supply* Issued: June 24, 2004
Sierra Pacific and Nevada Power 2003 Request for Proposals *Request for Proposals for Renewable Energy and Renewable Energy Credits* Date issued: June 27, 2003

List of Acronyms

BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
CCGT	Combined Cycle Gas Turbine
CFT	Call For Tender
COD	Commercial Operation Date
CPI	Consumer Price Index
DPP	Duke Point Power
DSM	Demand Side Management
ECP	Environmental Choice^{m} Program
EPAs	Electricity Purchase Agreements
EPC	Engineering, Procurement and Construction
GHG	Greenhouse Gas
GPCs	Green Power Certificates
GWh	Gigawatt Hours
HLH	Heavy Load Hour
IEP	Integrated Electricity Plan
IPPs	Independent Power Producers
LD	Liquidated Damages
LLH	Light Load Hour
LTEPA	Long Term Energy Purchase Agreement
MW	Megawatts
OATT	Open Access Transmission Tariff
PSCo	Public Service Company of Colorado
Q & A	Question and Answer
REAP	Resource Expenditure and Acquisition Plan
RFP	Request For Proposals
RPPI	Renewable Power Production Incentive
RRA	Revenue Requirements Application
UCA	Utilities Commission Act
WPPI	Wind Power Production Incentive

British Columbia Hydro and Power Authority
2005 Resource Expenditure and Acquisition Plan
British Columbia Utilities Commission
Project No. 3698388

DIRECT TESTIMONY OF RICHARD ROSENZWEIG

Q1. Please introduce yourself to the British Columbia Utilities Commission (Commission).

A. My name is Richard Rosenzweig. I am the Managing Director and Chief Operating Officer of Natsource LLC (Natsource). I am responsible for Natsource's global Advisory and Research Services business unit. Advisory and Research staff assist the company's global base of clients in Canada, Europe, Japan and the U.S. to assess the economic risks imposed by climate change policy and to develop strategies to manage risk and capture opportunities provided by the emissions market. We also assist clients to understand the impacts of policy design on market performance and provide them with insight regarding market evolution and pricing for greenhouse gas (GHG) commodities. Advisory staff also uses the unit's regulatory expertise to help clients structure emission reduction projects and estimate the value of emissions assets.

Q2. What are the subjects of your evidence?

A. First, I will discuss my qualifications and experience.

Second, I will discuss the report I have prepared in conjunction with Doug Russell of Natsource (the Report), attached hereto and marked **Exhibit B**.

Third, I will discuss the view of the investment community that the cost to reduce GHG emissions, and climate change policy more generally, represent potentially serious emerging financial liabilities for some companies. I will also describe how some companies, including U.S. electric utilities, and U.S. States are addressing this risk. Last, the testimony identifies how some utilities in the U.S are considering the potential costs of reducing GHG emissions in their planning and acquisition programs for new power supplies.

Qualifications and Experience

Q3. Please describe your professional qualifications and experience.

A. My education, qualifications, and professional experience are discussed in my Curriculum Vitae. It is attached hereto and marked **Exhibit A.**

My work with Natsource since 2000 involves providing advice and services to private firms, GHG funds, governments and international financial institutions on all aspects of climate change and renewable energy, including GHG risk assessment and management, market entry strategies, pricing information, trading system design, domestic policy development and international negotiations. I was involved in the first transactions of UK and Danish GHG allowances.

I have directed the firm's work in providing clients with estimates of prices of GHG compliance instruments. Natsource Advisory and Research staff has superior access to market data and transactions of GHG reductions from projects located around the world that utilize various technologies. The staff draws upon this knowledge and expertise in conducting extensive analyses of GHG markets, current market pricing, and future market dynamics for private firms, carbon funds, international financial institutions and governments.

For example, Natsource has drawn upon its market knowledge in conducting five comprehensive annual reviews and analyses of the emerging GHG market for the World Bank's Prototype Carbon Fund and Carbon Finance Business. Natsource is the only firm to have contributed to each of these reviews to date. The company has also completed reports on the GHG market and pricing that have been commissioned by the Electric Power Research Institute, Environment Canada, the European Commission, the Inter-American Development Bank, the International Emissions Trading Association, the International Energy Agency, the Pew Center on Global Climate Change, the U.S. National Commission on Energy Policy and many of the world's largest private firms.

Prior to joining Natsource, I was a Principal at the Washington law firm of Van Ness Feldman from 1998-2000. I served as Chief of Staff to the Secretary of Energy at the U.S. Department of Energy (DOE) from 1993 to 1996. My policy responsibilities with the DOE included the development and coordination of DOE strategy related to global climate change. I participated in the development of the Clinton Administration's Climate Change Action Plan, which incorporated the first project-based mechanism to reduce GHG emissions. I also helped negotiate

voluntary agreements between DOE and more than 600 electric utilities to achieve voluntary GHG reductions in the Climate Challenge program.

I have written extensively on the GHG market, the impacts of trading system design on achieving economic and environmental objectives, and the role of technology in addressing climate change. I have a Bachelor of Arts degree from Northeastern University and a Masters of Arts degree from American University in Political Science.

The Report

Q4. Please describe the scope of review and the methods used in the preparation of the Report.

A. The Report reviews model estimates of prices for GHG compliance instruments in the year 2015; posits three alternative GHG policy scenarios for 2015; and estimates a range of GHG prices for 2015 based upon these policy scenarios and model estimates. The policy scenarios were developed to reflect what we believe to be realistic alternative policy outcomes, given the current status of international climate change negotiations, the views of the parties involved, and the emerging climate change policies of Canada, the U.S., and Australia, with the latter two remaining outside of the Kyoto Protocol at this time.

To develop a range of GHG prices in 2015 under alternative policy scenarios, the Report considers: (1) relevant economic models of GHG prices in either 2015 or 2020, depending on the availability of 2015 estimates; (2) the implications of the different assumptions utilized in the models; and (3) the implications of the differences between the policy scenario in question and the specific assumptions and scenarios reflected in the models.

The Report also examines estimates in economic models of carbon taxes required to meet emission reduction targets in and beyond 2020, and identifies an approach for considering GHG compliance instrument prices in 2020 and the years following.

Q5. Did other individuals conduct work used in the Report?

A. Yes. I developed the alternative policy scenarios based on my extensive experience analyzing and developing climate policy in government and in the private sector. I conferred with Robert Youngman, Director of Economic Analysis at Natsource, in developing the three alternative 2015 policy scenarios and in providing a range of price estimates in 2015. The range of 2015 price estimates

we have developed is based upon model estimates, the assumptions incorporated in the models, and, where applicable, the differences between the policy scenarios we developed and those incorporated in the models. We consulted with Doug Russell, Managing Director of Natsource's Ottawa office. He provided analysis of the implications of the three policy scenarios for Canadian climate policy based on his experience and expertise in Canadian climate change policy, which is canvassed in his Direct Testimony.

Q6. Does the Report represent your view of how a series of climate change policy scenarios would affect GHG compliance instrument prices?

A. We believe that it is possible to understand how alternative policy scenarios will affect prices of GHG compliance instruments in 2015. However, there are many different variables and dynamics that will have a significant impact on GHG prices in the future. For example, if Russia were to restrict the supply of Assigned Amount Units in the GHG market, prices for Kyoto Protocol compliance instruments would be higher than if no such restrictions were to be imposed. Similarly, if there were unanticipated technological breakthroughs, prices would be lower than if such technology were not available.

With these caveats, we believe that the range of estimates included in the Report represents a reasonable band of prices that could result from each of the climate change policy scenarios considered in the Report.

Q7. What do you believe to be realistic price estimates for 2020 and the period after 2020? What is the range of price forecasts for that period and do you think there is a realistic approach to estimating prices so far into the future?

A. Deriving price estimates of GHG compliance instruments so far into the future is extremely challenging given the nearly infinite number of variables that will impact future GHG emissions and the prices paid for GHG compliance instruments in 2020 and during the remainder of the 21st century. In the Report, I describe the variables that will affect GHG emissions and the stabilization of concentrations of GHGs during the 21st century – which is the long-term objective incorporated in the United Nations Framework Convention on Climate Change (UNFCCC), and which will require very significant emission reductions on a global basis during the 21st century. The variables that will affect future emissions and stabilization include population growth and economic activity, energy intensity and carbon intensity.

Long-term modelling of prices in economic models that we reviewed is based on the assumption that the world will adopt a quantitative target concentration of GHGs in the atmosphere. The economic models reviewed in the Report assume that the international community will agree to stabilize concentrations of GHGs in the atmosphere at a 550 parts per million volume level. All concentration ceilings have an associated carbon budget for the 21st century – i.e. a finite budget of GHGs to emit over the next 95 years. Some of the key dynamics that will affect the cost of stabilization and the price of GHG compliance instruments in 2020 and after include the allocation of the budget between nations, when developing nations begin to participate in the effort to stabilize, technological advancements and the stabilization pathway that is ultimately selected (discussed below).

Economic models derive a wide range of carbon tax price forecasts, which can be used as proxies for GHG compliance prices for the period 2020 to 2040. As such, it is important to note that extrapolated carbon tax projections for the period of 2020 to 2040 are merely points along a long-term pathway to stabilization of concentrations. Prices vary widely depending on the emissions pathway that is chosen, the baseline emissions forecasts used to determine the level of emission reductions that will be required to achieve stabilization, and the technological assumptions incorporated in the model. For example, those models that assume more rapid emission reductions in the first half of the century estimate higher prices for 2020-2040 than those that assume pathways in which most of the emissions reductions take place in the second half of the century. Estimates of prices in 2020 in economic models we reviewed range from $1.39 (CDN) per tonne of carbon dioxide (CO_2) to $33.98 (CDN). Estimates of prices in 2040/50 range from $10.87 (CDN) to $84.97 (CDN) per tonne of CO_2.

There is not yet any indication regarding the emissions pathway to achieve stabilization that may ultimately be agreed to by the international community. There also is no understanding at present of how the carbon budget will be allocated among nations and when the developing countries will begin to participate in the effort to stabilize GHG emissions. In the absence of such, one approach that may be used regarding price forecasts from 2020 to 2040 for GHG compliance instruments would be to inflate 2015 price forecasts by 5% on an annual basis.

Views of Investment Community and U.S. Electric Utilities

Q8. What are the key long-term root causes of the constraints on GHG emissions identified in the Report?

A. There is scientific concern with respect to the potential magnitude and impacts of climate change. National governments, in partnership with the scientific community, formed the Intergovernmental Panel on Climate Change (IPCC) to advise them on the scientific basis, actual and likely impacts, and means of adapting to and mitigating, global climate change caused by GHG emissions from human activities. Since 1990, the formal reports of the IPCC show an accumulating body of scientific evidence that is resulting in increasing confidence that GHG emissions resulting from human activities are impacting the climate system.

Initial concern over climate change resulted in the UNFCCC, which established the goal of stabilizing concentrations of GHGs in the atmosphere. Subsequent work by the IPCC developed and synthesized scientific evidence regarding climate change, and increased many countries' concern over this phenomenon. This increased concern and countries' belief that current efforts were inadequate led to negotiation of the Kyoto Protocol and increasing efforts to take action. As of June 2005, 150 countries, including Canada, have ratified the Kyoto Protocol. It entered into force on February 16, 2005. The most important provision of the Kyoto Protocol is that it requires a group of industrialized countries to reduce their GHG emissions in the years 2008-2012 by 5.2% from a 1990 base year. Countries that accepted emissions limits under the Protocol, including Canada, have either developed policies to comply with them or are in the process of doing so.

Canada ratified the Kyoto Protocol in December 2002, thereby accepting its target of reducing GHG emissions to 6% below the 1990 level during 2008-2012, net of credits for "sinks" and international emission trades. The targets incorporated in the Protocol are but a first step in achieving the long-term objective incorporated in the UNFCCC to stabilize concentrations of GHGs in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system. Many analyses that have been undertaken regarding stabilization of concentrations conclude that significant levels of absolute reductions from 1990 levels must be achieved on a global basis to stabilize concentrations at levels under discussion by the international community. Thus, the Kyoto Protocol should be viewed as the first step in this effort. The international community likely will attempt to develop an international agreement

in the post-2012 period that considers the magnitude of reductions needed to stabilize atmospheric concentrations of GHGs.

Q9. What are the views of the investment community?

A. Many in the investment community have begun to recognize that requirements to reduce GHG emissions could have an adverse affect on both companies that produce fossil fuel-based energy and their customers that utilize fossil fuel-based energy to manufacture products and engage in other forms of economic activity. The potential impacts of climate policy have led many companies to thoroughly consider the impact of GHG reduction requirements on their businesses. Several companies in various economic sectors now incorporate a price of GHG emissions in their capital allocation process in order to determine whether investments are economic when considering the costs of complying with potential GHG emissions limitations. For example, Dow Chemical, American Electric Power (AEP), BHP Billiton, Chevron Texaco, and the Shell Group of companies now incorporate a GHG price and GHG emissions analysis into their investment decisions. BP developed an internal trading program so that it could determine the price of carbon throughout its various businesses. Several global financial institutions analyze the risk associated with GHG emission reduction requirements and scenarios in making lending decisions and in understanding liabilities associated with their existing portfolios. Information on these and other climate change strategies is provided by the website of the Carbon Disclosure Project, which surveys the business implications of climate change for the largest 500 companies in the world.[1]

Q10. What policies are U.S. states undertaking to address GHG regulatory risk while setting limits on costs?

A. While the U.S. federal administration has chosen not to participate in the Kyoto Protocol, the states of Oregon and Washington have established CO_2 emissions standards for developers of new energy facilities. Both programs incorporate provisions that allow regulated entities to pay a deemed amount per ton of CO_2 to a designated organization achieve compliance with the emissions standards. This effectively serves to cap the cost of complying with the requirement.

In 1997, Oregon adopted House Bill 3283, which established CO_2 emissions standards for developers of new energy facilities.[2] The rules were updated in 2000 and apply to base-load gas plants, non-base load power plants and non-

[1] http://www.cdproject.net
[2] http://www.energy.state.or.us/climate/3283b.htm

generating energy facilities that emit CO_2. The rule requires new power plants to offset CO_2 emissions 17% below the most efficient combined cycle natural gas generation technology as a condition of obtaining an operating permit. [3]

Entities have two options to comply with this regulation. They can: (1) implement projects to avoid, sequester or displace CO_2 directly or through a third party (projects must meet set criteria); or, (2) they may elect to pay a deemed amount per ton of CO_2 to The Climate Trust, a state-sanctioned non-profit entity responsible with securing qualifying offsets. Current rates for CO_2 offsets purchased through The Climate Trust are $1.16/tonne (CDN) plus administrative costs in 2002.[4] The cost of an offset can be adjusted, but not by more than 50% in either direction during any two-year period.

On March 9, 2004, the Governor of Washington signed into law a bill that requires new power plants with a capacity greater than 25 megawatts (MW) to offset 20% of their CO_2 emissions over a 30 year lifetime. The law also requires existing power plants that expand their generating capacity by at least 25 MW, or increase their CO_2 emissions by 15% or more, to offset 20% of their CO_2 emissions over a 30 year lifetime. The law requires that affected plants offset 20 % of their projected CO_2 emissions based on a 30-year project life and 60% operating capacity.[5]

The Washington rule is modeled largely on the Oregon CO_2 offset rule described above. In order to achieve compliance, applicants would have the option of paying $1.99 (CDN) per tonne per offset to a qualified organization.[6] Alternatively, applicants could directly invest in or undertake mitigation projects to meet the 20% offset requirement. Companies could also apply carbon credits purchased on the market towards complying with their offset requirements. Credits must be “real, verified, permanent and enforceable” and be approved by the state’s Energy Facility Site Evaluation Council.

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[3] http://www.energy.state.or.us/climate/ccnewst.pdf

[4] The rate for CO_2 offsets purchased through the Climate Trust is $0.85/short ton CO_2 + administrative costs (http://www.oregon.gov/ENERGY/SITING/docs/ccnewst.pdf); confirmed in telephone call with Climate Trust, June 30, 2005. This price per short ton was converted into a price per tonne, and then was from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in Report attached as Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

[5] http://www.leg.wa.gov/pub/billinfo/2003-04/House/3125-3149/3141-s_pl_03102004.txt

[6] The rate for CO2 offsets in Washington is set at US $1.60/tonne CO_2. This price was converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

Q 11. What actions are U.S. power companies and electric utilities taking to reduce their emissions and to incorporate climate change regulatory risk into their resource evaluation and procurement processes?

A. Under the Bush Administration's Climate Vision program, the electric utility industry has agreed to reduce its emissions intensity by 3 to 5% below 2000-2002 baselines levels by the 2010-2012 period. Calpine, Entergy, FPL Group, PSEG, Exelon Corporation, AEP, WE Energies and Cinergy have joined the U.S. Environmental Protection Agency's Climate Leaders Group. The Climate Leaders program is an industry-government partnership that works to develop long-term, comprehensive strategies to address climate change, including the creation of emissions inventories and the establishment of emission reduction goals. With the exception of two companies, all of the Climate Leaders listed here have committed to voluntary GHG emission reduction goals.

Some electric utilities have made significant commitments to reduce their GHG emissions without there being a legal requirement to do so. For example, AEP, the largest coal-fired generator in the U.S., is a founding member of the Chicago Climate Exchange and has committed to reduce its GHG emissions by 1% below baseline levels (average of 1998-2001 emissions) in 2003, 2% in 2004, 3% in 2005 and 4% in 2006. Cinergy Corporation has committed to reducing its emissions by 5% from 2000-2010. Entergy Corporation has committed to stabilizing its emissions at 2000 levels from 2001-2005. In May 2005, Exelon Corporation announced a voluntary goal to reduce GHG emissions by 8% from 2001 levels by the end of 2008. In the 2004 Annual Report, the CEO of Duke Energy called for U.S. policy makers to consider various policy instruments to encourage a transformation to a less carbon-intensive economy and endorsed a carbon tax or similar policy that would cover all economic sectors.

Several U.S. utilities have begun to evaluate the risk of GHG regulations in their resource planning and procurement processes. For example, PacifiCorp., a major utility serving the Western U.S. including Utah, Wyoming, Oregon, Washington, and parts of Idaho and California, published a 2004 Integrated Resource Plan (IRP) that includes a base case cost adder for GHG of CDN $10.96/tonne, and high-end sensitivity cases of CDN $34.27 and $54.85 per tonne as well as a low-end sensitivity case of CDN $0/tonne.[7] In addition, as part of its two most recent Request for Proposals (RFP), PacifiCorp applied the CDN

[7] The price in the RFP was US $9/short ton CO_2. This price per short ton was converted into a price per tonne, and was then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in the Report attached as Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

$10.96/tonne adder to all GHG emitting resources and includes the cost of GHG emissions in the bid evaluations.

In the Public Service Company of Colorado's (PSCo) recent RFP process, a GHG cost adder is added to bid prices in the amount of CDN $12.34/tonne beginning in 2010 and escalating at 2.5% a year beginning in 2011. Further details concerning PSCo's RFP are found in the Direct Testimony of Mary Hemmingsen, and in particular Exhibit C to her Direct Testimony. In addition, PSCo's 2003 IRP incorporated a resource technology screening analysis in which carbon dioxide regulations would impose costs ranging from CDN $8.20 to $16.40/tonne starting in 2009.[8,9]

The base case scenario used in Idaho Power Company's draft 2004 IRP assumes a CDN $16.86/tonne cost for GHG emissions beginning in 2008, while Idaho Power's high-end risk sensitivity is CDN $67.46/tonne beginning in 2008. Idaho Power characterizes these estimates as representing reasonable estimates of the risk that Idaho Power and its customers face due to potential future regulation of GHG emissions.

Avista Utilities, which serves Washington and Idaho, has a 2003 IRP incorporating a carbon tax scenario with prices of CDN $1.80/tonne in 2004, increasing to CDN $15.04 per tonne of CO_2 in 2023, consistent with Northwest Power Planning Council assumptions..[10,11]In addition, Portland General Electric's 2002 IRP included a carbon tax scenario using a value of CDN $13.67/tonne.[12]

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[8] Public Service Company of Colorado, 2003 Least-Cost Resource Plan, 30 April 2004, Xcel Energy, http://www.xcelenergy.com/docs/corpcomm/Document1of4.pdf

[9] The values in the IRP were US $6 to $12 per short ton CO_2. This price per short ton was converted into a price per tonne, and was then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

[10] "An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios," Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory, October 2004, http://eetd.lbl.gov/EA/EMP/reports/56403.pdf

[11] The values in the IRP were US $1.32 per short ton CO_2 in 2004 and US $11 per short ton CO_2 in 2023. These prices per short ton were converted into prices per tonne, and were then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

[12] Wiser and Bolinger, 2004, op. cit. The value in the IRP was US $10 per short ton CO_2. This price per short ton was converted into a price per tonne, and was then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate

In a December 2004, the California Public Utilities Commission (PUC) adopted a policy requiring utilities to use an imputed cost for GHG emissions in developing long-term resource plans. The policy requires that the state's largest utilities (Pacific Gas & Electric, Southern California Edison Company and San Diego Gas & Electric) apply a GHG adder of CDN $10.94 to $34.18 per tonne to fossil prices bid in future procurement starting in 2007.[13,14] Utilities must justify the value within that range that they choose until the PUC adopts a single value.[15] The PUC's decision notes that the adder will be used to evaluate the cost to customers of different resources and thereby to aid in the selection of resources, but will not change prices.[16]

In 2003, the Montana Public Service Commission adopted Default Electric Supplier Procurement Guidelines.[17] The Guidelines provide a framework for default supply utilities (DSUs) to consider resource needs in the procurement process. They also provide a basis for Commission review and assessment of the prudence of a DSU's planning and procurement actions. DSUs are instructed to obtain and consider recommendations from an advisory committee in their planning and procurement process. They also must use modeling and analysis to evaluate, manage and mitigate risks relating to future environmental regulations or taxes on emissions of CO_2, mercury and criteria pollutants. No specific GHG price adder is proposed in the Guidelines.

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utilized in Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on June 8, 2005.

[13] California Public Utilities Commission, Decision 04-12-048, 16 December 2004, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43224.PDF;
Natural Resources Defense Council (NRDC) internal memorandum, 22 December 2004, http://www.fypower.org/pdf/NRDC_GHG.pdf.

[14] The price range for the GHG adder was US $8 to $25 per short ton CO_2. This price per short ton was converted into a price per tonne, and was then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244, consistent with the conversion rate utilized in Appendix B to this testimony. The exchange rate was taken from www.x-rates.com on 8 June 2005.

[15] NRDC, 2004, op. cit.

[16] Ibid.

[17] Administrative Rules of Montana, Utility Division, Sub-Chapter 82, Default Electric Supplier Procurement Guidelines, 31 December 2003, http://www.psc.state.mt.us/eDocs/AdministrativeRulesandNotices/

Conclusion

Q12. Does that conclude your evidence?

A. Yes.

EXHIBIT A
TO TESTIMONY OF RICHARD ROSENZWEIG

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Summary of Professional Experience

Natsource, LLC, Managing Director and Chief Operating Officer
Washington, D.C. (November 2000 – Present)

Managing Director, Natsource LLC. Appointed Chief Operating Officer of the company in May, 2005. Opened the Washington, D.C. office of leading global firm with expertise in emissions and renewable energy markets. Managed all aspects of opening the office including the establishment of administrative functions, hiring staff of ten professionals and overseeing all business and product development. Responsible for creating the firm's advisory and research business. Developed the company's climate change, clean air and renewable energy practice within three years. Clients include leading multinational energy and manufacturing firms, carbon funds, international financial institutions and governments. Services include assisting clients to assess and manage their economic risk and to capture opportunities resulting from climate change and renewable energy policy, providing price estimates and valuations of emissions and renewable energy assets, and consulting on all components of emissions and renewable energy markets. Completed reports on the greenhouse gas (GHG) market and prices commissioned by the Electric Power Research Institute, Environment Canada, the European Commission, the Inter-American Development Bank, the International Energy Agency, the International Emissions Trading Association, Pew Center on Global Climate Change, the U.S. National Commission on Energy Policy, the World Bank's Carbon Finance Business, and many of the world's largest private firms. Published extensively regarding the evolving international GHG market, the impacts of alternative trading system design, and the role of technology in addressing climate change.

Played a major role in the development of the firm's asset management business including the initiation of the Greenhouse Gas-Credit Aggregation Pool (GG-CAP), the first private sector mechanism designed to purchase and manage delivery of GHG emission reductions usable for compliance with emissions limitations. Assisted in the development of all products including the world's first delivery risk model to screen and score GHG emission reduction projects in order to purchase reductions and to construct highly valued portfolios of emissions reductions for buyers. Also developed all marketing materials including a fundraising prospectus for the GG-CAP. Supported the firm's overall transaction services business and was involved in the first transactions of UK GHG compliance instruments and Danish emissions allowances. Represent the firm as a speaker at conferences and as press spokesman.

Van Ness Feldman, Principal
Washington, D.C. (December 1998 – November 2000)

Non-lawyer partner at one of Washington's premier energy and environmental law firms. Developed a clean air, energy and global climate change practice. Participated in negotiations on behalf of one of the largest electric utilities in the U.S., in conjunction with a leading environmental organization, to develop a comprehensive solution to air quality and climate change issues. Provided consulting services to leading electric utilities and energy companies regarding the international climate change negotiations to implement the Kyoto Protocol. Published articles funded by the Electric Power Research Institute on key provisions of the Kyoto Protocol including the allocation of liability between buyers and sellers of emissions rights. Also served as a co-author of papers describing the role and economic benefits of technology in addressing climate change in the 21st century. Assisted project developers structure two of the largest international GHG reductions projects and secure host country approvals during an international pilot phase designed to gain experience with market-based mechanisms.

Alcalde and Fay, Partner
Washington, D.C. (June 1997- December 1998)

Assisted several companies, including British Petroleum (BP), develop and implement strategies to address global climate change issues. Participated in the development of BP's climate change strategy including the creation of its internal emissions trading system. Provided counsel to companies during the period leading up to the negotiation of the Kyoto Protocol. Facilitated a policy dialogue process involving approximately 20 utilities, BP, and a leading environmental organization. Policy dialogue led to the introduction of legislation in the U.S. Senate to provide firms with credit for investments that reduce GHG emissions prior to there being a legal requirement to do so. Worked with the Electric Power Research Institute and the Pacific Northwest National Laboratory to develop a multi-year program designed to develop a long-term technology strategy to address climate change. Secured the financial and substantive participation of major project sponsors and structured and facilitated advisory committee meetings and project briefings in the U.S. and Europe with senior officials from the private sector, government and non-governmental organizations.

Washington International Energy Group, Senior Vice President
Washington, D.C. (June 1996 - June1997)

Designed and implemented strategies for major energy trade associations such as the Edison Electric Institute and the Interstate Natural Gas Association of America to address the issue of global climate change. Developed and facilitated a process for a major coal-based electric utility to assess the future of clean air regulation and its cost. Co-authored a major study that evaluated the future competitiveness of all nuclear units in the U.S. based upon emerging competition in electric power markets.

U.S. Department of Energy, Chief of Staff to the Secretary of Energy
Washington, D.C. (January 1993 – March 1996)

During this period, the U.S. Department of Energy employed 140,000 people and had a budget of approximately $18 billion.

Developed and communicated departmental positions to the White House, other federal departments and agencies, Members of Congress, state and local governments, departmental constituencies, the public, and the media. Coordinated Secretarial involvement in and support of all Administration initiatives.

Facilitated the development of departmental policy agendas, implementation strategies, and tracking systems to monitor progress. Coordinated strategies in such diverse areas as global climate change; nuclear weapons testing; waste management; the Department's international energy, environmental and national security initiatives; the Department's budget submissions; and downsizing of the Department. Played a key role in the development of the Climate Change Action Plan in 1993 that incorporated the first project-based mechanism to reduce GHG emissions. Also assisted the Secretary in negotiating the first voluntary agreements between the Department and the electric utility industry designed to reduce or avoid GHG emissions.

Managed all staff and their assignments in the Office of the Secretary. Communicated Secretarial priorities and agendas to direct reports and Departmental executive officers, including all Senate confirmed officials. Monitored implementation. Assigned and supervised preparation of all briefing documents and substantive analyses to inform decision-making. Ensured that alternative points of view were provided to the Secretary prior to decision making. Supervised preparation of all briefing materials for internal and external meetings and speeches. Responsible for Congressional and Public Affairs functions.

Madison Public Affairs Group, Executive Vice President
Washington, D.C. (1985 - 1993)

Co-founder of one of Washington's largest public affairs firms specializing in energy and environmental policy. Clients included numerous Fortune 500 companies and think tanks.

Directed services in the areas of policy development, facilitation, and legislative representation. Engaged in the development of the Acid Rain provisions incorporated in the Clean Air Act Amendments of 1990, Amendments to the Public Utility Holding Company Act , and Federal Power Act incorporated in the Energy Policy Act of 1992 and nuclear waste legislation. During this period, also directed the Keystone Energy Futures Project that proposed far reaching changes to power generation and transmission policies.

Education

1984 Masters of Arts, Political Science
American University, Washington, D.C.

1982 Bachelor of Arts, Political Science
Northeastern University, Boston, MA

NATSOURCE®

I. Background/Overview

This report provides information as to how potential global climate change policies could affect market prices of greenhouse gas (GHG) compliance instruments in 2015. It describes three potential climate policy scenarios at the national and international levels and outlines potential policy responses by the federal government of Canada. The report also examines estimates in economic models of prices of GHG compliance instruments in and beyond 2020, and identifies an approach for considering GHG prices in 2020 and the years following.

Climate change is a century scale issue. Governmental responses are in their infancy, and policy will change in response to new scientific understanding of the impacts and magnitude of climate change and economic and technological developments. As a result, the dynamics that will affect long term climate policy are difficult to quantify and too numerous to describe. Therefore, in order to estimate potential prices of GHG compliance instruments in 2015, this report first describes potential policy responses by the collective international community and by national governments to address climate change following the end of the Kyoto Protocol's (KP) first commitment period in 2012. We then describe how these policy responses could affect the market, and use prices estimated by models incorporating similar policy scenarios to develop 2015 price estimates for GHG compliance instruments.

For the longer-term post 2020 commentary in this paper, we review economic models that assume that the international community will agree to stabilize concentrations of GHGs in the atmosphere at a 550 parts per million volume (ppmv) level. Many issues including: (1) the allocation between nations of the emission reductions that will be required to achieve the GHG concentration; (2) when developing nations begin to participate in this effort; (3) technological developments; and (4) the pace at which the reductions are required during the 21st century will all have a great impact on the cost of stabilization and the price of GHG compliance instruments in 2020 and after. In light of these and other challenges to deriving price estimates for 2020 and beyond, we identify a proxy approach that may be used regarding price forecasts for GHG compliance instruments from 2020 to 2040.

II. Drivers of Long Term Climate Policy

International Legal Framework—The United Nations Framework Convention on Climate Change

Canada is a Party to the UN Framework Convention on Climate Change (UNFCCC). The paragraph below describes the Convention's environmental objective.

> "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."

The international community has not agreed to the concentration level that constitutes "dangerous anthropogenic interference" with the climate system, and opinion varies widely.

Stabilizing Concentrations of Greenhouse Gases in the Atmosphere

For the most part, the debate over climate policy to date has been over near term emissions limitations incorporated in the KP and not over stabilization of concentrations of GHGs in the atmosphere. These are very different.

The objective of the UNFCCC—stabilizing concentrations of carbon dioxide (CO_2) and other GHGs—is not the same as stabilizing emissions. Because emissions accumulate in the atmosphere, the concentration of CO_2 and other GHGs will continue to rise for several hundred years even if emissions are held at current levels or slightly reduced.

The UNFCCC process has not yet specified a particular target concentration. However, in order to stabilize concentrations at any level ranging from 450 ppmv to 750 ppmv,[1] very large reductions of worldwide emissions (from emission levels that might be anticipated if present trends were to continue) would be required during the course of the 21st century. The magnitude of the reductions is dependant on the ceiling that is ultimately selected.

Stabilizing concentrations at 550 ppmv has often been discussed by the scientific community given that it roughly coincides with a doubling of concentrations levels in the atmosphere from pre-industrial levels. It is also frequently used as a baseline hypothesis for models examining climate sensitivity. According to the Intergovernmental Panel on Climate Change (IPCC), achieving such a concentration ceiling would require significant action on the part of developed and developing countries. Significant emission reductions below current levels would be required to achieve such a concentration ceiling on a global basis, and emissions intensity would have to fall to a fraction of today's levels. Achieving this level of reductions and the commensurate improvements in emissions intensity would require a transformation in the way in which society produces, transforms, distributes, and consumes energy. Stabilization of concentrations at any level below 750 ppmv requires greater deployment of non-emitting technologies that are commercially available and the development of technologies such as carbon capture and storage and advanced transportation that are not yet widely deployed throughout the economy.

If the emissions targets incorporated in the KP are achieved, emissions from developed countries participating in the KP would fall approximately 5.2% from a 1990 base year from 2008-2012. Developing country emissions will continue to grow. Talks are scheduled to begin in 2005 at the international level regarding the shape of an international climate policy framework following the end of the first KP commitment period in 2012. The international community would need to agree to emission reduction requirements for both developed and developing countries if the world is going to get on a path to stabilize concentrations. In this regard, the United Kingdom has set a long-term goal of reducing emissions by 60% by 2050 and has advocated the same target for all industrialized countries. To implement such a goal, it has developed a comprehensive energy plan for the next half century that would lead to significant reductions in its use of fossil fuels. The European Union has recently stated a goal of capping temperature increases at 2 degrees

[1] Concentrations of CO_2 today are approximately 380 ppmv, and, under a range of illustrative scenarios developed by the Intergovernmental Panel on Climate Change (IPCC), are forecast to rise rapidly and reach as high as 540 to 970 ppmv by the turn of the next century (IPCC Third Assessment Report: *Climate Change 2001 Synthesis Report – Summary for Policymakers*).

Centigrade. Achieving this objective would require significant levels of absolute emission reductions. On 19 November 2004, Canada's Environment Minister, in response to the official ratification of the KP, and its definitive entry into force on 16 February 2005, indicated that the initial reductions included in the Protocol were "just a start." He went on to say that over the next 50 years or so, emissions must fall 70% below 1990 levels,[2] one of the most ambitious scenarios yet laid out by a government in the developed world.

Concentrations of GHG emissions are driven by four variables. These are: (1) population growth; (2) per capita economic growth; (3) reliance on increased energy use to support economic growth (energy intensity); and (4) the dominance of fossil fuels in providing this energy (carbon intensity). Expressing this concept as an equation yields the following:

Population growth rate
+ Per capita economic growth rate
+ Energy intensity growth rate
+ Carbon intensity growth rate
= Growth rate CO_2 emissions

This equation was developed by Dr. Yoichi Kaya, director of the Research Institute of Innovative Technology for the Earth in Japan. The scenarios allow for the calculation of future emissions and concentrations levels during the century. For example, if population was to double over the next century and the other three factors did not change, CO_2 emissions would double.[3]

One of the scenarios developed by the IPCC, IS92a, has been utilized frequently as a reference case for analysis to determine emissions levels and concentrations without climate policy. It is assumed to be a middle range scenario with respect to the key factors driving emissions. More recently, the IPCC developed scenarios known as the Special Report on Emissions Scenarios (SRES) for use in its third assessment report. For the most part, the SRES incorporate many of the same technological assumptions as the IS92 scenarios.[4]

Most scenarios of future emissions projections suggest that the expected increases in population and economic growth will overwhelm the continued improvements in energy and carbon intensity. For example, some believe a plausible scenario to be a doubling of population over the next century combined with continued annual economic growth rates of 1.8 percent in per capita income, resulting in a global economy in 2100 that is 12 times the current size. If the other two factors that affect emissions did not change, then a 12-fold increase in CO_2 emissions would occur during the 21st century. The only way to stabilize concentrations in this scenario would be to reduce emissions per dollar of economic output to less than one-twelfth of their current level. This represents a 92% reduction.[5] Part of this reduction would be accomplished through

[2] As reported in the *Globe and Mail*, November 19, 2004.
[3] Edmonds, Jae, T. Wilson and R. Rosenzweig, 2000."Global Energy Technology Strategy Addressing Climate Change, Initial Findings From an International Public-Private Collaboration", Global Energy Strategy Project. Battelle.
[4] Nakicenovic, N., et. al., 1996, IPCC Special Report, A Special Report of IPCC Working Group III, Emissions Scenarios, Summary for Policy-makers, Cambridge University Press.
[5] Op. Cit., Edmonds, et. al.

improvements in the amount of energy used to create a dollar of economic output (energy intensity), and part through dramatically reducing carbon emissions from the energy sector (carbon intensity). Simply put, population and economic growth will lead to rising emissions unless fundamental transformation of the energy system is achieved through technological breakthroughs.

The above illustrates the scale of the potential emissions reductions that would be required to achieve stabilization of concentrations and leads one to the conclusion that the emissions limits incorporated in the KP are but a first step towards achieving the long-term objective of the UNFCCC.

Regardless of the long term concentration target that is chosen, the key dynamics that will affect the cost of stabilization and the price of GHG compliance instruments in 2020 and after include the allocation of the carbon budget between nations, when developing nations begin to participate in the effort to stabilize, technological advancements, and the pathway that is adopted to achieve the target concentration ceiling (i.e. the stabilization path). With regard to the latter, those models that assume more rapid emission reductions in the first half of the century estimate higher prices for 2020-2040 than those that assume pathways in which most of the emissions reductions required for stabilization take place in the second half of the century.

III. Future Climate Policy Scenarios and Canadian Responses

The preceding discussion highlights just a few of the dynamics that can affect long-term climate policy and emissions performance. In order to derive prices for GHG market instruments in 2015, this report describes three alternative climate policy scenarios that are driven by the current policy and regulatory framework. They are simplified versions of potential futures. This approach limits the consideration of the variables that will influence future policy to those that are grounded in politics, competitiveness, and environmental performance. In this regard, a key determinant of Canada's eventual policy response will be decisions made by the U.S. The scenarios that follow evaluate potential outcomes in which the U.S. at the federal level: (1) continues to remain outside the international climate policy framework following 2012; (2) agrees to participate in an international climate policy framework after 2012 that requires emission reductions; or (3) develops a domestic program that imposes emission reduction requirements but remains outside of an international program.

The direction of U.S. policy likely will have a significant impact on future Canadian policy given concerns with national competitiveness. Canada is currently out of step with the U.S. on the KP. Canada is a Party to the agreement, while the U.S. is not. Given the importance of the U.S. economy on Canadian competitiveness (approximately 90% of Canadian exports are to the U.S.), the Government of Canada will likely seek to develop a policy that is consistent with the approach taken by the U.S. As such, we have developed three possible scenarios that could shape Canada's future policy response.

Three Post 2012 Policy and Market Scenarios

This section describes three future international and national policy scenarios for the post-2012 time frame. The report provides a range of prices for GHG compliance instruments in 2015.

Scenario 1 – Continuation of the Kyoto Protocol, no U.S. engagement or action ("KP continuation, no U.S./ no further Canadian action")

Description

In this scenario, it is assumed that the national emissions limitations from the first KP commitment period (2008-2012) for those countries that were Parties to the Protocol will be maintained in the years immediately following 2012. More stringent targets would not be adopted because under this scenario the U.S., the world's largest emitter, would not join a post-2012 international agreement and would not take action at the federal level to reduce GHG emissions. As a result, developed countries that participated in the KP could determine in this scenario that taking on more stringent requirements would have adverse impacts on national competitiveness. Developing countries' emissions would continue to rise in this scenario. This scenario may be possible in light of: (1) continued uncertainty with respect to U.S. action on climate change; (2) the possibility that developing countries will not agree to mandatory emissions limitations; and (3) previous views in the U.S. Senate that the U.S. would continue to remain outside of any international climate change agreement that imposes reduction requirements if the agreement did not require developing countries to adopt emissions reduction targets in the same compliance period.

Under this scenario it would be unlikely that the Government of Canada would impose more stringent reduction requirements to achieve climate related objectives. Taking on more aggressive targets could have adverse impacts on Canadian firms that export to the U.S. as the cost to reduce emissions could put them at a competitive disadvantage. In this scenario, emissions growth would occur and emissions intensity requirements for thermal power generators would remain virtually the same as under the Large Final Emitters regime. Further emission reductions or improvements in emissions intensity would be consistent with technological improvements that could occur. It is unlikely that the targets for the generation sector would be eliminated or rolled back given continued calls for lower emitting sources of power to achieve other air quality and public health objectives such as reducing urban smog and acid rain, and to reduce emissions of hazardous air pollutants such as mercury. The U.S. and Canadian Governments would likely posit further progress on climate change on breakthrough technologies not yet widely deployed in the economy.

Relevant model estimates

In order to develop price estimates for GHG compliance instruments in 2015, we have considered economic model estimates that are most relevant for each scenario that is considered. Three model estimates are relevant in considering prices under this scenario (KP continuation, no U.S./no further Canadian action).

- Bernard et al, estimates #1 and #2 ($13.68 and $41.05[6]) consider prices in 2010 without U.S. participation, assuming KP continuation, and incorporating sinks policy changes from Conference of the Parties (COP) 6.5 in Bonn and COP 7 in Marrakech. Estimate # 2 considers sales limits. Thus, these models and their price estimates have some similarities with this policy scenario.

[6] Unless otherwise noted, all price estimates in this report were calculated in year 2001 $US, and then converted from $US to $CDN using an exchange rate of US $1 = CDN $1.244. The exchange rate was taken from www.x-rates.com on 8 June 2005.

- Similarly, Nordhaus estimate #2 ($8.71) considers prices in 2015 without U.S. participation, assuming KP continuation, incorporating sinks policy changes, but not considering sales limits.

We note that these model estimates assume that Canada maintains its participation in the international climate regime. As a result, prices estimated by these models could be slightly higher than in a scenario in which Canada does not participate. All the models we reviewed assume that Canada is a net buyer of KP compliance instruments. The increase in net demand for compliance instruments with Canadian participation would tend to lead to higher prices.

Price estimates in 2015 under this scenario (KP continuation, no U.S./no further Canadian action)

As noted above, if developed countries maintain their KP targets beyond 2012, economic growth and the reduction of low-cost abatement options could lead to higher prices for GHG compliance instruments, although technological development could mitigate this effect somewhat. The two low model estimates ($8.71 and $13.68) result because there is an assumption that sellers such as Russia do not impact the market by taking action to restrict supply in an attempt to maximize revenue. We call these sales limits throughout the report. In contrast, the high estimate ($41.05) makes the opposite assumption, but assumes more optimal results for sellers than could be achievable in practice.

In light of these considerations, we estimate that prices in this scenario would increase to $19 - $31 in 2015.

Advances in technological developments that are greater-than-forecast will tend to result in prices toward the low end of this range, or perhaps lower. Similarly, if the Clean Development Mechanism (CDM) is implemented in such a way as to increase the supply of KP compliance instruments beyond expected levels, this would also push prices lower. Conversely, higher-than-expected economic growth and less-than-expected advances in technology could push prices toward the high-end of this range, or perhaps higher.

Scenario 2: KP entry into force plus post-2012 international agreement including the U.S. and Canada ("KP plus, with U.S./Canada")

Description

In this scenario, developed countries, including the U.S. and Canada, agree to a post-2012 international agreement that imposes emissions limitations on the U.S. and requires more stringent reductions than were agreed to in the first Kyoto period. This scenario appears to be plausible given: (1) the clear importance of U.S. engagement in an international effort to address climate change (2) the need for global emissions to decrease from 1990 levels in order to meet the UNFCCC objective of stabilizing GHG concentrations in the atmosphere at levels that have been discussed; (3) the benefits that international emissions trading would have in lowering U.S. compliance costs; (4) the impact that state-level and regional U.S. policies would have in raising the political profile of the climate change issue among the public; and (5) the increased costs for companies to comply with differing sets of rules under the state programs. In this scenario, potentially large U.S. and Canadian demand for compliance instruments could significantly impact international markets and prices for GHG compliance instruments under the KP in 2015.

Relevant model estimates

Several economic models consider similar, if not always identical scenarios, and are therefore relevant in considering prices under this scenario ("KP plus, with U.S./Canada"). A summary of some of the key differences between the assumptions incorporated in these models and those in this scenario, and associated implications, follows.

- Bernard et al, estimates #3 and #4 ($26.12 and $41.05) consider prices in 2015 with U.S. participation, incorporating sinks policy changes from COP 6 *bis* in Bonn and COP 7 in Marrakech. Estimate #2 assumes sales limits. However, these estimates assume targets described in KP continuation (scenario 1), rather than the more stringent targets we assume in this scenario in the post-2012 period. These price estimates are therefore lower than they would be under this scenario.
- Jakeman et al ($47.27) considers prices in 2015 under a KP plus scenario in which Annex B (developed) countries' emissions targets are 5% below their 2008-12 targets, and Russia's and Ukraine's targets are 10% below. The model also takes sinks and sales limits into account. However, it does not include U.S. participation. Consequently, prices are lower than they would be with the U.S., due to the impact of U.S. demand.
- Manne and Richels ($73.40), two prominent climate change modelers in the U.S., consider prices in 2020 under a KP plus scenario in which the U.S. takes on its original KP target (7% below 1990 levels) and other Annex B countries' emissions targets are 10% below their 2008-12 targets. The model takes sinks and sales limits into account. Since prices are estimated for 2020, they reflect 5 more years of emissions growth, and are therefore higher than they would be if they were estimated for 2015.
- Several models (McCracken: $51.00; Kurosawa et al: $33.59; Kainuma et al: $17.42; Bernstein et al: $13.68; McKibbin et al: $14.93; average = $26.12) consider prices in 2020 in a scenario in which the U.S. participates. However, the scenario is similar to that which is considered in which the KP continues but developed countries do not take on more aggressive targets as described in this scenario. In addition, these models do not take into account sales limits or sinks developments in 2001 and 2002. Modeling prices for 2020 raises prices, as does the way in which the models considered sinks. On the other hand, prices in these models can be lower because they assume the more modest targets considered in Scenario 1 and do not take sales limits into account.

Price estimates in 2015 under this scenario, (KP plus, with U.S./Canada)

In this scenario, several dynamics, including increased demand for GHG compliance instruments (largely from the U.S.), and more stringent targets for developed countries, would significantly increase demand and prices relative to Scenario 1 (KP continuation, no U.S./no further Canadian action). As in Scenario 1, economic growth by 2015 and the reduction of low-cost abatement options would also likely lead to higher prices, although technological advancement could mitigate this effect somewhat. We would expect that prices under this scenario would be higher than in either of the other two scenarios we consider for 2015.

In considering the relevant model estimates, we made some inexact adjustments to each estimate to reflect the directional impact of the dynamics noted above. We estimate that prices for GHG compliance instruments in 2015 under this scenario would be $37 - $50 based upon: (1) adjusted model estimates; (2) current prices; (3) consideration of the directional impacts of reduction of

existing low-cost abatement options; and (4) consideration of the directional impacts of technological developments.

A key question in this scenario is the stringency of the U.S. target. If the U.S. receives a relatively less stringent emissions target, it could be able to meet its target largely through domestic reductions that are available at a lower marginal cost of abatement than the international clearing price for GHG compliance instruments. This would reduce U.S. demand (and therefore international prices) significantly relative to a scenario in which the U.S. took on ambitious targets, such as its original KP target of 7% below 1990 levels. Therefore, prices could be higher or lower than the estimated range based on the target adopted by the U.S. Similarly, the stringency of other Annex B countries' targets will affect price.

Scenario 3: Kyoto Protocol with more stringent requirements for industrialized countries plus separate U.S./Canada reduction program (KP plus with more stringent requirement, plus separate U.S./Canada program)

Description

Under this scenario, we assume KP entry into force plus a post-2012 international agreement that imposes more stringent emissions limitations but does not include U.S. and Canada and developing countries. However, the U.S. and Canada develop a domestic program that requires reductions and allows for trading flexibility in 2015 (KP plus with more stringent requirement, plus separate U.S./Canada program).

In this scenario, the U.S. and Canada do not join a post-2012 international agreement, but instead decide to adopt domestic reduction programs that allow regulated firms to purchase GHG instruments for compliance. Other developed countries that are Parties to the KP would take on more stringent targets post-2012 in order to make further progress in the effort to achieve stabilization of atmospheric concentrations of GHGs. Trading flexibility provisions likely would be incorporated in any U.S. and Canadian domestic trading program in order to lower compliance costs. For example, the programs could incorporate the following elements:

- Mandatory cap and trade program limiting emissions;
- Companies having full compliance flexibility, enabling them to use:
    - All KP compliance instruments, including certified emission reductions (CERs) created by CDM projects, emission reduction units (ERUs) created by Joint Implementation projects, and assigned amount units (AAUs);
    - U.S. and Canadian allowances under the cap and trade program;
    - U.S. and Canadian domestic offsets (if an offset program is developed); and
    - Compliance instruments from any other national emissions trading program.

Legislation introduced in the U.S. by Senators McCain and Lieberman in October 2003 incorporated an emissions limitation and allowed the use of KP instruments for a portion of compliance.

Under this scenario, two separate systems would emerge. The first would be the KP system and the second would be the U.S./Canadian system. The U.S./Canadian system could impact the KP system through potentially strong demand for KP compliance instruments. However, given that KP participants' demand for compliance instruments is already high in this scenario, prices for KP compliance instruments may be higher than the marginal cost of abatement under the U.S.

and Canadian programs. This would mean that firms from KP Parties would pay more for GHG compliance instruments in 2015 than U.S. and Canadian firms. In such a case, it is possible that prices for KP instruments would be differentiated according to the buyer. For example, sellers of CERs would be able to charge KP participant buyers up to the international clearing price for GHG compliance instruments, but would only be able to charge U.S. and Canadian buyers up to the domestic marginal cost of abatement, since it is unlikely that these buyers would be willing to pay more for KP compliance instruments. In this scenario, U.S. and Canadian demand for KP compliance instruments may not impact prices in the KP system.

Relevant model estimates and price estimates in 2015 under this scenario (KP with more stringent requirement, plus separate U.S./Canada program)

Based on our review of the economic modeling literature and discussions with experts in this field, we are unaware of any economic modeling effort to date that has considered a scenario similar to one in which developed country Parties to the KP take on more stringent targets in the post-2012 time frame and in which the U.S. and Canada establish separate domestic programs that allow regulated firms to purchase external instruments for compliance. Such a model would be instructive, given the possibility that separate trading systems could emerge in the future. As noted above, a key question would be the extent of U.S. and Canadian demand for KP compliance instruments, which in turn would depend on the cost of these instruments, the stringency of U.S. and Canadian emissions targets, and the marginal costs of abatement under the U.S. and Canadian programs.

The closest approximation to this scenario in the economic models we reviewed is Scenario 2 in which the U.S and Canada participate in an international agreement in the post-2012 period. The principal difference between that scenario and this one is that the U.S. and Canada would likely take on less stringent targets in this scenario than under Scenario 2. Less stringent U.S. targets in this scenario imply lower demand for compliance instruments than in the prior scenario and therefore lower prices for KP instruments. As noted above, U.S./Canadian demand for KP compliance instruments could be reduced to zero if the marginal cost of abatement for the U.S/Canadian program was lower than the price of KP instruments. Alternatively, prices for KP instruments could be differentiated based on the buyer. Sellers of KP instruments would prefer to sell to KP participants at higher prices, but U.S./Canadian buyers could potentially be able to find supply at lower prices if there were surplus available in the market. In either case, U.S./Canadian demand would have little or no effect on KP instrument prices for KP participant buyers.

Estimates of prices under this scenario can provide a basis for assessing the likelihood of additional U.S./Canadian demand in the KP system. Two estimates have been prepared of U.S. compliance instrument prices under the McCain-Lieberman domestic emissions trading proposal, which called for a year-2000 emissions cap starting in 2010. An economic modeling analysis by the Massachusetts Institute of Technology (MIT) estimated that prices in 2015 under the cap would be $13.68.[7] Another analysis by the Energy Information Administration of the U.S. Department of Energy estimated that prices in 2015 would be $27.37.[8] The average of these two

[7] Paltsev, S., J. M. Reilly, H.D. Jacoby, A. D. Ellerman and K.H. Tay (2003), "Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal," Report No. 97, MIT Joint Program on the Science and Policy of Global Change, June.
[8] Energy Information Administration (2003), "Analysis of S.139, the Climate Stewardship Act of 2003," Office of Integrated Analysis and Forecasting, U.S.Department of Energy, SR/OIAF/2003-02, June.

estimates, rounded to the nearest dollar, is $19.90. Without further information available, we estimate that prices in the U.S. system in 2015 will be approximately $12 - $25.

We would expect that prices in the KP system in this scenario would be lower than in Scenario 2 because of less stringent U.S. targets, but potentially higher than in the first scenario described because of the potential that the U.S. would impose some demand in the KP system and because developed countries would take on more stringent targets. As noted above, we estimate that prices in 2015 in Scenario 2, in which the U.S and Canada participate in a post-2012 international agreement, will be approximately $37 - $50. We estimate that prices in the first scenario in which Parties to the KP maintain their targets following 2008-2012, the U.S. continues its current stance at the federal level on climate policy, and Canada maintains targets for the power sector but does not participate in an international agreement, will be approximately $19 - $31. Without further information available, we estimate that prices in the KP system under Scenario 3 would be approximately $25 - $37. If KP prices are in this range in 2015, and if U.S./Canadian prices are in the range of $12 - $25, U.S. demand might not impact prices for KP buyers. However, this question requires significant further analysis.

Summary of Price Expectations for 2015

Table 1 below summarizes our price expectations for 2015 based on consideration of estimates from relevant models. As noted throughout the report, there remain numerous variables outside the scenarios that could have a significant impact on the price projections.

Scenario	Description	Relevant Models	Estimated Price Range in 2015 Based on Relevant Models
1	KP continuation, no U.S./no further Canadian action beyond existing 2005 LFE plan	Bernard et al estimates #1 and #2 ($13.68 and $41.05) Nordhaus estimate #2 ($8.71)	$19 - $31
2	KP plus, with U.S. and Canada participating	Bernard et al estimates #3 and #4 ($26.12 and $41.05) Jakeman et al ($47.27) Manne and Richels ($73.40) McCracken ($51.00) Kurosawa et al ($33.59) Kainuma et al ($17.42) Bernstein et al ($13.68) McKibben et al ($14.93)	$37 - $50
3	KP plus with more stringent requirement, plus separate U.S./Canada program with less stringent targets than KP Plus	No models with directly comparable scenarios found. Closest was analysis done for McCain-Leiberman bill MIT ($13.68) US Department of Energy ($27.37)	$25 - $37

Post 2020 Modeling

Deriving price estimates of GHG compliance instruments so far into the future is extremely challenging given the many variables that will impact their prices. As noted earlier in the discussion on long term global climate policy, the ultimate objective of the international legal regime (UNFCCC) is to stabilize concentrations at a yet-to-be-specified level. The variables that will affect future emissions and stabilization include population growth and economic activity, energy intensity and carbon intensity.

Long-term modeling of prices in economic models that we reviewed is based on the assumption that the world will adopt a quantitative target concentration of GHGs in the atmosphere. The economic models reviewed in this report assume that the international community will agree to stabilize concentrations of GHGs in the atmosphere at a 550 ppmv level. All concentration ceilings have an associated carbon budget for the 21st century – i.e. a finite budget of GHGs to emit over the next 95 years. Some of the key dynamics that will affect the cost of stabilization and the price of GHG compliance instruments in 2020 and after include the allocation of the budget between nations, when developing nations begin to participate in the effort to stabilize, technological advancements, and the stabilization pathway that is ultimately selected (discussed below).

A number of economic models have looked at potential costs of achieving stabilization to nations or regions, expressed in terms of percentage of GDP. While instructive when comparing different scenarios, the variables associated with these forecasts makes translation of these model results into a price per tonne of CO_2 extremely difficult. A closer proxy for considering GHG compliance instrument prices in 2020 and beyond is found in models that forecast what the carbon tax that would be required to reach long term emissions reduction targets, and that we have reviewed for this report.

However, it is important to note that extrapolated carbon tax projections for the period of 2020 to 2040 are merely points along a long term pathway to stabilization of concentrations. Prices vary widely depending on the emissions pathway that is chosen, the baseline emissions forecasts used to determine the level of emission reductions that will be required to achieve stabilization, and the technological assumptions incorporated in the model.

By way of illustration, Table 2 below summarizes model results for eight models that looked at carbon tax levels needed to reach a stabilized 550 ppmv concentration by the end of the century.[9]

Model	Authors	2020 forecast	2040/2050 forecast	2100 forecast
Asia Pacific Integrated Model (AIM)	M. Kainuma, T. Morita, T. Masui, K. Takahashi, Y. Matsuoka	$4.42	$50.98	$163.28
Emissions Projection and Policy Analysis (EPPA)	J. Macfarland, J. Reilly, H. Herzog (MIT)	$3.73 (2030 price)	$61.18	$1,189.61
Global Relationship	A. Kurosawa (Institute of			

[9] From "Review of Post 2020 Modelling Insights for BC Hydro," Trexler Climate and Energy Services, June 9, 2005 draft report.

Assessment to Protect the Environment (GRAPE)	Applied Energy)	$33.98	$84.97	$1,070.66
IMAGE 2.2	D. an Vuuren, B. deVries, B. Eickout, T. Kram (National Institute of Public Health and the Environment)	$15.30	$23.80	$64.58
Multiregional Approach for Resource and Industry Allocation (MARIA8)	S. Mori (Tokyo University) and T. Saito (Hitachi)	$10.20	$59.48	$50.98
Model for Evaluating Regional and Global Effects of GHG Reduction Policies (MERGE4.2)	A. Manne (Stanford University) and R. Richels (Electric Power Research Institute)	$3.74-$4.08	$10.87-$11.22	$122.36
Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE)	K. Riahi, L. Schrattenholzer (ECESP), E. Rubin, D. Hounshell (Carnegie Mellon University) , M. Taylor (UC Berkeley)	$7.81	$20.05	$151.93
Mini-Climate Assessment Model (mini-CAM)	J. Edmonds, J. Clarke, J.Dooley, S. Kim, S. Smith (University of Maryland)	$1.39	$22.54	$75.80

As can be seen from the above table, model predictions for 2020 range from $1.39 per tonne of CO_2 to $33.98; for 2040/2050 the range is from $10.87 to $84.97; and in 2100 the range is from $50.98 to $1,189.61. Those models that assume more rapid emission reductions in the first half of the century estimate higher prices for 2020-2040 than those that assume pathways in which most of the emissions reductions required to achieve the target concentration take place in the second half of the century.

Price Forecasting for 2020 to 2040

There is not yet any indication regarding the emissions pathway to achieve stabilization that may ultimately be agreed to by the international community. There also is no understanding at present of how the carbon budget will be allocated among nations and when the developing countries will begin to participate in the effort to stabilize GHG emissions. In the absence of such, an alternative to using economic model estimates of prices in 2020 and beyond is required. Based on the range of uncertainties that leading experts associate with future climate change policy, one approach that may be used regarding price forecasts from 2020 to 2040 for GHG compliance instruments would be to inflate 2015 price forecasts by 5% on an annual basis. While it obviously provides a very rough proxy, this approach has the advantage of avoiding the difficulties involved in trying to synthesize extremely diverse results from economic models that incorporate wide-ranging assumptions regarding baseline emissions, technological advancement, and the stabilization pathway that is implemented in the 21st century.

British Columbia Hydro and Power Authority
2005 Resource Expenditure and Acquisition Plan
British Columbia Utilities Commission
Project No. 3698388

DIRECT TESTIMONY OF DOUG RUSSELL

Q1. Please introduce yourself to the British Columbia Utilities Commission (Commission).

A. My name is Doug Russell. I am the Managing Director of Natsource's Ottawa office. We provide advisory services to private firms regarding climate change policies that would require reductions of greenhouse gas (GHG) emissions, the development of domestic emissions trading systems or the implementation of climate change-related regulations. We also provide services to the Government of Canada, and capacity building services to international organizations such as the World Bank and the Canadian International Development Agency.

Q2. What are the subjects of your evidence?

A. First, I will discuss my qualifications and experience.

Second, I will discuss my role in the preparation of the Natsource report (the Report) attached as Exhibit B to the Direct Testimony of Richard Rosenzweig.

Third, I will review the federal government's most recent climate change plan and the accompanying budget implementation measures.

Qualifications and Experience

Q3. Please describe your qualifications and experience.

A. My education, qualifications and professional experience are discussed in my Curriculum Vitae, which is attached hereto and marked **Exhibit A**.

I have been employed by Natsource since July 2002. My clients include large corporations, developed and developing country governments, and international organizations. I have worked on Canadian and international climate change policy for 15 years, the first half of which was as a Senior Executive in the Government of Canada. The latter half was as President of my consulting company, Global Change Strategies International Inc., from 1996 to 2002, and as Managing Director of Natsource from 2002 onwards.

In the government, I co-headed Canada's negotiating delegation to the United Nations Framework Convention on Climate Change (UNFCCC) from 1992 to 1996. During the last year in Government, I occupied the position of Acting Director General of the Air Pollution Prevention Branch of Environment Canada where I was responsible for domestic and international policy responses to climate change, urban smog, acid rain and stratospheric ozone depletion. From 1993 to 1996 I was the Chairman of the Annex 1 Experts' Group on the UNFCCC and in that role directed the work of the Organization for Economic Co-operation and Development and International Energy Agency Secretariats that provided some of the groundwork for the GHG market-based instruments incorporated in the Kyoto Protocol.

I have over 25 years of experience in the public and private sectors dealing with international and domestic policy development related to broad-scale environmental issues such as the regulation of GHG emissions. My work in the private sector includes developing a corporate climate change strategy for the Shell Group of companies, a study for Pew Centre on Global Climate Change on how multinational corporations established and met their GHG reduction targets, and various capacity-building initiatives related to climate change in Argentina, the Caribbean, China and Nigeria.

I have also delivered numerous presentations and briefings on the Kyoto Protocol and the emergence of carbon emissions as a commodity.

I have a Bachelor of Science degree in mathematics and a Masters in Public Administration from Dalhousie University.

The Report

Q4. What role did you play in the development of the Report?

A. Based on my experience and expertise in Canadian climate change policy, I provided analysis on the implications of the policy scenarios on Canadian climate policy described in the Report that was developed by Richard Rosenzweig.

Canadian GHG Regulation

Q5. What is climate change?

A. Climate change is the fluctuation in temperature, precipitation and all other aspects of the Earth's climate due to the natural greenhouse cycle and human induced greenhouse effect through the release of GHG emissions. GHGs that contribute to climate change and are controlled under the Kyoto Protocol include carbon dioxide (CO_2), methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons and sulphur hexofluoride.

Q6. What is the Kyoto Protocol?

A. The Kyoto Protocol is an international agreement under the UNFCCC that requires a group of developed countries to reduce their emissions an aggregate 5.2% in 2008-2012 from a 1990 base year. The Kyoto Protocol was agreed to at the third Conference of the Parties to the UNFCCC in Kyoto, Japan, on December 11, 1997.

The Kyoto Protocol requires Canada to reduce its GHG emissions to approximately 560 megatonnes (Mt) – 6% below 1990 levels – in the first commitment period (January 1, 2008 to December 31, 2012, the "First Commitment Period"). On December 17, 2002, the Government of Canada ratified the Kyoto Protocol to the UNFCCC. The Kyoto Protocol entered into force on February 16, 2005. Negotiations on provisions for a second commitment period are due to start in 2005.

Canada and over 180 countries have now ratified the UNFCCC, which entered into legal force in March 1994. The UNFCCC states "the ultimate objective of this Convention and any related legal instruments is to achieve … stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[1] In 1995, the

[1] Article 2, UNFCCC.

international parties reviewed the progress made in implementing the UNFCCC and concluded that further action was required. This gave rise to the Kyoto Protocol adopted in 1997. The Kyoto Protocol requires developed countries to reduce their emissions in aggregate of 5.2% from 1990 during the period of 2008-2012. Developing countries, such as China, India and Brazil, have no obligation under the Kyoto Protocol to reduce their emissions. Yet, the scientific community, represented by the Intergovernmental Panel on Climate Change in its Third Assessment Report of 2001, noted that stabilizing CO_2 concentrations would require substantial reductions[2] of emissions. Given that the Kyoto Protocol currently sets emission targets only up to 2012, and involves only part of the world, most observers of the climate policy process agree that to reach the UNFCCC's objective of stabilizing GHG concentrations, a series of amendments to the Kyoto Protocol or its successor treaties, setting increasingly demanding GHG emission targets, will be required over several decades post-2012.

Q7. How has the Government of Canada responded to the Kyoto Protocol?

A. On April 13, 2005, the Government of Canada released its revised Kyoto Protocol plan entitled "Moving Forward on Climate Change: A Plan for Honouring our Kyoto Commitment" (the 2005 Climate Change Plan). A copy of the 2005 Climate Change Plan is attached hereto and marked **Exhibit B**. The Government of Canada has also set out a number of enabling initiatives in Bill C-43, the *Budget Implementation Act, 2005* (Bill C-43 or Budget 2005). A copy of Parts 13 and 14 of Bill C-43 are attached hereto and marked **Exhibit C.** Bill C-43 received Royal Assent on June 28, 2005.

The 2005 Climate Change Plan includes measures designed to reduce annual GHG emissions by 270 Mt of CO_2 equivalent by the end of the First Commitment Period in 2012. Total federal investment over 8 years (2005-2012) is budgeted at approximately $10 billion.[3] Two billion dollars was committed in previous plans and budgets. Budget 2005 committed $5 billion, and the remaining investments will be made in subsequent budgets.

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[2] For example, the United Kingdom has adopted a goal of reducing GHGemissions by 60% from current levels by 2050. See also Wigley, T.M.L. (2005), "The Climate Change Commitment," *Science*, vol. 307, pp. 1766–69, in which he states "the Constant-emissions results reinforce the common knowledge that, in order to stabilize global-mean temperatures, we eventually need to reduce emissions of greenhouse gases to well below present levels".

[3] All dollar figures reported in this testimony are Canadian dollars.

Table 1
Summary of Federal Expenditures and Expected Results

Program	Expenditures ($ Billion)	Annual Emissions Reductions (Mt)
Climate Fund	4-5	75-115
Partnership Fund	2-3	55-85
Existing Programs	2.8	40
Large Final Emitters	n/a	36
Business As Usual sinks (Agriculture and Forestry)	n/a	10-20
Renewable Energy	Up to 1	15
Automobile Industry	n/a	5.3
One Tonne Challenge	0.12	5
Greening Federal Operations	Internal reallocation	1

A key component of the 2005 Climate Change Plan is the "Climate Fund". Budget 2005 plans to put an initial $1 billion in the Fund and indicates that a further $3-4 billion could be forthcoming in future budgets. The Fund is intended to purchase both domestic and international offsets at the rate of 75-115 Mt per year. The detailed budget documents profile the $1 billion funding to be $10 million in 2005-06, $50 million in 2006-07, $300 million in 2007-08, $300 million in 2008-09, and $340 million in 2009-10. The Climate Fund is to be managed as an Agency under the Minister of Environment.[4]

For planning purposes, the average price used by the Government of Canada in determining the number of tonnes the Climate Fund might purchase is $10 per tonne.[5] A priority will be to purchase domestic credits to be retired against Canada's Kyoto Protocol commitment. All purchases are planned to be made under a competitive arrangement aimed at getting the most cost-effective credits for compliance and to foster other sustainable development goals.

Consultations on how the Climate Fund will implement its obligations will take place throughout the summer of 2005. The intent is to retire all domestic credit purchases against Canada's national account. Because there is no intention for these particular credits to be traded in a secondary market, the purchasing criteria

[4] See Part 13 of Bill C-43, which creates the Canada Emissions Reduction Incentives Agency, reporting to the Minister of Environment.
[5] Briefing by Government Officials, 13 April 2005.

could conceivably be less stringent than comparable criteria for international Kyoto Protocol units. A draft of the domestic offset system rules is due to be released in July 2005 for consultation with provinces, territories, industry, First Nations and stakeholders.

Another element of the 2005 Climate Change Plan is the expansion of the Wind Power Production Incentive (WPPI) and the introduction of the Renewable Power Production Incentive (RPPI). Budget 2005 proposes to quadruple the WPPI to a target of 4000 megawatts (MW) of new wind generating capacity and to remove provincial eligibility caps and limits on project size. Budget 2005 also proposes to introduce the RPPI to support other renewable energy sources, including small hydro, biomass and tidal power, with a target of 1500 MW of new generating capacity. Adjustments were also made to the capital cost allowances related to renewable energy under the *Income Tax Act*.

Q8. What GHG regulatory regime is proposed by the 2005 Climate Change Plan?

The third key component of the 2005 Climate Change Plan is the proposed Large Final Emitters (LFE) regulatory system. LFEs are companies in the electricity generation, oil and gas, mining, pulp and paper, chemical, iron and steel, smelting, cement, and glass sectors. They are responsible for just under 50% of total GHG emissions in Canada. BC Hydro will be a LFE company.

Under the 2005 Climate Change Plan, the LFE program will seek to achieve 45 Mt of reductions against the new national baseline of 270 Mt. The Government of Canada's current operating assumption is that Parts 5 and 11 of the *Canadian Environmental Protection Act, 1999* (*CEPA*) will be the enabling legislation. The federal government intends to add GHGs to Schedule 1 of *CEPA*. It is expected that the LFE GHG protocol setting out how the LFE regulatory system could be implemented under *CEPA* will be released for public consultation shortly. Draft regulations, including draft initial sectoral allocations, will be consulted on by the end of 2005.

Although the Government of Canada intends to implement the LFE system under *CEPA*, it has signalled its intent in the 2005 Climate Change Plan to make maximum possible use of equivalency agreements[6] with the provincial and

[6] Section 186 of *CEPA* allows the Government of Canada to conclude equivalency agreements with provinces and territories whose legislation and regulation achieves an equivalent environmental outcome to that of *CEPA*. If a particular province could demonstrate that its provincial regulations deliver the same performance as the national LFE regulation within their jurisdiction, then industry in that province can be governed by those provincial regulations.

territorial governments in the implementation of the LFE system. Under this approach, the federal Minister of Environment would be able to leave implementation to individual provinces and territories, as long as the provincial or territorial legislation achieves the same environmental result as the proposed LFE system.

The 2005 Climate Change Plan makes it clear that all previous commitments[7] that have been made concerning the LFE system will be honoured. This includes the commitment that the cost of compliance to industry, including thermal power generators, will be no more than $15 per tonne of CO_2 equivalent. Part of the price guarantee will be handled by allowing contributions to the Technology Fund[8] proposed in Budget 2005. The total amount of contributions to that Fund will be limited to the equivalent of 9 Mt per year. The 2005 Climate Change Plan notes that "appropriate mechanisms" will be implemented to achieve the price cap guarantee to be applied to the remaining 36 Mt annually. These mechanisms will be consulted on as part of the LFE consultations.

LFE companies may comply with the proposed *CEPA* regulations in a number of ways including:

- Investment in in-house reductions;
- Purchase of emissions reductions from other LFE companies that have done better than their target;
- Purchase of domestic offset credits;
- Purchase of international credits provided that these represent verified emissions reductions; and
- Investments in Technology Investment Units under the Greenhouse Gas Technology Investment Fund.[9]

Compliance penalties may be $200 per tonne, but will be subject to consultations as part of the *CEPA* regulation process.

Once initial allocations are made to individual companies that are covered under the LFE system, they will need to implement measures to ensure they meet their emissions reduction targets. The reduction of GHG emissions will necessarily become another business risk that must be incorporated into business planning.

[7] See Appendix 2 of the "2005 Climate Change Plan" for a full listing of how prior government commitments for LFE companies will be handled in the 2005 Climate Change Plan.
[8] See Part 14 of Bill C-43, which creates the Greenhouse Gas Technology Investment Fund under the Minister of Natural Resources.
[9] See Part 14 of Bill C-43 for details.

Q9. You mentioned that the 2005 Climate Change Plan will honour the commitment that the cost of compliance to industry will be no more than $15 per tonne of CO_2 equivalent. Do you expect the Government of Canada's commitment to honour the $15 per tonne price cap to continue past the First Commitment Period of 2008-2012?

The $15 per tonne price assurance is set out in a letter dated December 18, 2002 from Herb Dhaliwal, the then Minister of Natural Resources Canada (the Letter). A copy of the Letter is attached hereto and marked **Exhibit D.** The Letter addressed concerns that the market price for emissions units (domestic credits or permits and foreign emissions units) could rise above $15 per tonne. The Letter provides that the $15 per tonne price assurance is for the First Commitment Period only. To date, the $15 per tonne price assurance has not been embedded in legislation.

The maintenance of the $15 per tonne price cap following 2012 is highly uncertain, primarily because there is no agreement on the post-2012 international policy architecture to address climate change.

Q10 What is the total quantity of GHG emission reductions that will likely be required from the fossil fuelled electricity sector under the 2005 Climate Change Plan?

A. The Government of Canada has not yet made public what their business as usual scenario is for the fossil fuelled electricity sector and so it is difficult to predict the exact quantity of emissions reductions that will be required. However, on a relative basis, the 2005 Climate Change Plan indicates that the most that any one sector will be required to contribute will be 12% of the total projected business as usual emissions for 2010 from their sector. It is expected that the 12% will apply to the thermal electricity generating sector.

Q11 How will natural gas-fired electricity be treated compared to coal-fired electricity?

A. For existing power plants, it is likely that both coal and natural gas will face the same emissions intensity target. Given that coal is approximately twice as emissions intensive as natural gas, a larger compliance burden will be placed on coal fired plants.

Q12 How will new generation facilities be treated compared to existing generation facilities?

A. New generation facilities will be required to meet Best Available Technology Economically Available standards. By way of illustration, previous discussion papers on the LFE system suggested that the standard for new power generation facilities be set at 370 tonnes of CO_2 equivalent per gigawatt hour (t/GWh), roughly that of a new combined cycle gas turbine power plant. Those same discussion papers had suggested that the national standard for existing power generation facilities be set at 558 t/GWh.[10]

It is expected that the *CEPA* regulations to be released this fall will propose allocations for both new and existing thermal power generation plants.

Conclusion

Q13. Does that complete your testimony?

A. Yes.

[10] "Allocation of Greenhouse Gas Emission Reductions in the Electricity Sector", Presentation by the LFE Group of Natural Resources Canada to Federal/Provincial/Territorial meeting, Toronto, November 20, 2003.

EXHIBIT A
TO THE TESTIMONY OF DOUG RUSSELL

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SUMMARY OF PROFESSIONAL EXPERIENCE

Natsource Managing Director
Ottawa ON (July 2002 – Present)

Managing Director, Natsource LLC and Managing Director of GCSI- Global Change Strategies International, a division of Natsource Asset Management Corporation.- Ottawa office. Responsible for the operations of Natsource Advisory Services in Canada, and for business development in the emerging Canadian GHG emissions market. Project manager of a number of Natsource projects to advise large Canadian corporations on their potential exposure to potential GHG emissions regulation and the development of appropriate corporate response strategies. Project manager and/or author or co-author of studies related to the operations of markets in Canada, including a study on the feasibility of cross border emissions trading with the USA and Mexico. Project manager on a study that examined trends in U.S. federal and state actions on climate change and their potential impacts on Canadian policy. Provide advice on current and planned policy developments related to climate change to companies and associations in the cement, forestry, manufacturing, chemicals, power generation and oil and gas sectors of the Canadian economy. Project manager for climate change and emissions markets capacity building projects in Indonesia, the Caribbean, and India. Developed and presented numerous talks on Canadian climate change policy and emissions markets for diverse audiences including the financial community, risk managers and assessors, the National Round table on the Environment and the Economy and the Air and Waste Management Association.

GCSI – Global Change Strategies International Inc. President
Ottawa ON (November 1996 – July 2002)

Co-founder and eventual sole owner of GCSI – Global Change Strategies International Inc, a Canadian firm dedicated to working with progressive corporate and public sector organizations to anticipate and respond to the challenges and opportunities of global change. Responsible for the overall management and operation of GCSI including management of numerous international and domestic projects for both corporate and public sector clients in the area of climate change strategies. Built the business from a two person operation in 1996 to a network of over 14 staff and senior associates with senior expertise in all areas of climate change, including mitigation strategies, policy development, technology deployment, risk management and climate change science. Provided consulting services to the Royal Dutch Shell group of companies as they developed their overall corporate strategy on climate change. Co-authored a study for the Pew Center on Global Climate change on how multinational corporations such as IBM, Toyota, United Technologies, ABB and Shell set and meet greenhouse gas reduction targets. Project manager for the development of national communications on climate change for the governments of Trinidad and Tobago, the Bahamas and Barbados. Project manager for the development of a National Sector Strategy under the auspices of the World Bank for the country of Argentina. Project manager for the writing of the descriptive elements of Canada's national climate change plan. Project manager for the NAFTA Commission for Environmental Cooperation to develop a comprehensive reference report describing air quality management systems in North America. The final report laid out the air pollution protection systems that exist in each of the three North American countries, presented the legal requirements for each country, and described the institutional arrangements that evolved out of the legal requirements over time.

Federal Government of Canada – Acting Director General, Air Pollution Prevention Directorate, Environment Canada Ottawa, ON (August 1995 – April 1996)

Directed a staff of over 70 professionals in the development of Canadian policy on major air issues including stratospheric ozone depletion, climate change, acid rain, smog, fine particulate matter and airborne persistent organic pollutants (POPs). Chaired numerous federal-provincial and NGO stakeholder meetings related to air issues. Participated as Head of Delegation or co-head of Delegation to international negotiations on stratospheric ozone depletion and climate change. Provided advice on all air issues to the Minister of Environment.

Federal Government of Canada – Director, Air Issues Branch, Environment Canada, Ottawa, ON (October 1993 – August 1995).

Directed a staff of 10 professionals to develop policy related to air issues including climate change, ozone depletion, acid rain, and smog. Advised on the establishment of federal-provincial and federal-NGO consultation committees and policy development approaches related to air issues in Canada. Co-headed Canada's delegation to the inter-sessional meetings of the UN Framework Convention on Climate Change. First Chairman of the Annex I Experts' Group to the UN Framework Convention on Climate Change, and in this capacity directed the work of the OECD and IEA Secretariats on implementation issues such as reporting and inventories for Annex I countries.

Federal Government of Canada – Director, Climate change Negotiations, Environment Canada, Ottawa, ON (December 1990 – October 1993)

Managed a staff of 5 professionals charged with research on, and development of, Canada's negotiating positions leading up to the adoption and eventual signature of the UN Framework Convention on Climate change at the 1992 Earth Summit in Rio de Janeiro.

Federal Government of Canada – numerous policy, scientific and weather services positions, Ottawa, Toronto, Halifax, Gander (July 1973 – December 1990)

Drawing on post-graduate training as a meteorologist, and a post graduate degree in Public Administration, performed numerous scientific and research functions for the Atmospheric Environment Service of Environment Canada. During the 1980's evolved into policy and staff positions in Canada's weather service including examination of the role of the private sector in the provision of weather services, advising on the nature and scope of weather services for agriculture and forestry operations, and a senior policy advisor to the Assistant Deputy Minister of Canada's Weather Service.

EDUCATION

1980 Master of Public Administration
Dalhousie University Halifax, N.S.

1973 Bachelor of Science, Major in Mathematics
Dalhousie University Halifax, N.S.

EXHIBIT B
TO TESTIMONY OF DOUG RUSSELL

Project Green

Moving Forward on Climate Change

A Plan for Honouring our Kyoto Commitment

www.climatechange.gc.ca

2005

Government of Canada
Gouvernement du Canada

Canada

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Executive Summary

Our climate change Plan will contribute significantly to cleaner air for Canada's cities, enhance biodiversity, help to preserve wild spaces and generally improve the quality of life for Canadians.

Climate change is a global challenge, and the Kyoto Protocol is the only global mechanism with targets to reduce greenhouse gas (GHG) emissions. Canada is a strong supporter of the Kyoto Protocol.

Canada's Kyoto target is challenging. However, Canada has many advantages that will help us rise to that challenge. The Government of Canada is committed to the transformative, long-term change required to make reductions in GHG emissions while ensuring continued economic growth. In achieving that transformation, we believe we will meet our Kyoto target while maintaining a productive and growing economy.

As well as transforming our economy, boosting our economic competitiveness and enabling Canada to achieve its short-term and longer term climate change goals, our 2005 Climate Change Plan will contribute significantly to cleaner air for Canada's cities, enhance biodiversity, help to preserve wild spaces and generally improve the quality of life for Canadians.

Encouraging innovation and the development of environmental technology is a key aspect of the Government's approach to climate change in the longer term. New technologies can provide Canadians with the ability to reduce GHG and other harmful emissions while enjoying the benefits of a competitive economy.

The 2005 Climate Change Plan is built on six key elements:

- **Competitive and Sustainable Industries for the 21st Century**: The Plan is designed to spur innovative and technological advancement, situating Canada's industries for a competitive advantage in the 21st century. It outlines a large final emitter system that will enable Canada's largest emitters to contribute to national climate change objectives in a manner that facilitates growth and competitiveness. The Government and the automobile industry have reached an agreement that will see technological advancement realize substantial emission reductions from the sector. Along with fighting climate change, increasing Canada's capacity of wind and other emerging renewable energy will help to diversify our energy mix and position our industries as leaders in growing international markets.
- **Harnessing Market Forces**: The Plan uses market mechanisms to tap GHG reduction potential across the economy. The innovative Climate Fund will invest in emissions reductions from citizens and businesses throughout Canada, spurring innovation at a national level. The Climate Fund will also invest in international emissions reductions in a manner that advances Canada's broader sustainability interest. Participating in the international market brings domestic economic and environmental benefits, as well as a means of advancing our development objectives and gaining experience in a trading market that is expected to be of growing importance over time.
- **A Partnership among Canada's Governments**: Cooperative action is critical to our success in fighting climate change. The Partnership Fund will maximize potential partnerships with provinces and territories. Under the Partnership Fund, governments will identify mutual priorities and share in the undertaking of major investments in technologies and infrastructure development. The federal government will

play a leadership role, by deepening its commitments to green its own operations.

- **Engaged Citizens**: Citizens are truly Canada's best asset in its fight against climate change. A sustainable environment is important to Canadians, and, through the One-Tonne Challenge and other federal programs, this Plan will provide citizens with the tools they need to take action.
- **Sustainable Agricultural and Forest Sectors**: One natural advantage Canada has in rising to the challenge of climate change is our vast forests and agricultural lands. Properly managed, these can be valuable in sequestering GHG emissions from the atmosphere.
- **Sustainable Cities and Communities**: This Plan recognizes the synergies between the parallel efforts of fighting climate change and greening our cities and communities. The Government of Canada's *New Deal for Cities and Communities*, which includes significant investment in sustainable infrastructure, will help advance our climate change goals.

It is estimated that the approaches outlined in the Plan, with an associated federal investment in the range of $10 billion through 2012, could reduce GHG emissions by about 270 megatonnes annually in the 2008–2012 period.

Budget 2005 laid the foundation for our Plan to fight climate change, and took an important step in providing resources to the Plan. Funding provided included:

- **Clean Fund** (renamed the Climate Fund in this Plan): a minimum funding of $1 billion;
- **Partnership Fund**: $250 million, with the possibility that funding could grow to $2–$3 billion over the next decade;
- **Renewable Energy**: $200 million for the Wind Power Production Incentive, $100 million for the Renewable Power Production Incentive and $300 million for tax incentives for efficient and renewable energy generation; and
- **Programs**: $2 billion for existing climate change programs.

The Budget noted that more action will be required in the future and that the Government will introduce additional measures as part of this climate planning process, as resources permit and as we learn from our domestic investments and international experience.

Our approach to climate change action builds on previous approaches and incorporates transparency, ongoing evaluation and learning. We will make modifications and course corrections to our Plan over time, including an annual review and reallocation of climate change spending to ensure that investments are effective and cost-efficient and result in real and verifiable GHG emission reductions. We will report annually to Canadians on our progress, beginning in 2008.

The Government of Canada is committed to engaging provinces and territories, municipalities, Aboriginal peoples, industry, non-governmental organizations and all Canadians in the implementation of the Plan so as to maximize the conditions of success.

Introduction

"The Government reiterates that it will respect its commitment to the Kyoto Accord on climate change in a way that produces long-term and enduring results while maintaining a strong and growing economy. It will do so by refining and implementing an equitable national plan, in partnership with provincial and territorial governments and other stakeholders."

Speech from the Throne — October 2004

Overview

The Government of Canada is committed to the transformative, long-term change required to make deep reductions in greenhouse gas (GHG) emissions while ensuring continued economic growth. This change is essential for the protection of our natural environment, in particular our Arctic region, a competitive and sustainable economy and the quality of life of Canadians.

Climate change is a global challenge — the affect on the world's climate is the same regardless of where GHG emissions are released. For that reason, the Government of Canada is committed to global multilateral approaches to addressing this challenge. The Kyoto Protocol is the only global mechanism with targets to reduce GHG emissions, although its membership is not as broad as Canada would wish. However, the Protocol has broad international support and contains innovative flexibility mechanisms that Canada put considerable effort into designing. For these reasons, Canada is a strong supporter of the Kyoto Protocol.

A key feature of the Protocol is its emission reduction targets for individual countries. Targets were set to bring discipline and the necessary pressure for collective international action; Canada's Kyoto target is particularly challenging.

Even though Canada's target is ambitious, it makes sense for Canada to take action on climate change.

Canada has many advantages that will help us rise to that challenge. Our natural resource and other industrial sectors are world leading and technologically advanced. We have vast forests and agricultural lands that, properly managed, can be valuable in sequestering GHGs. All orders of government are engaged and demonstrating leadership. As well, Canadians are concerned and want to make a difference.

Even though Canada's target is ambitious, it makes sense for Canada to take action on climate change. This means aiming to reach our short-term goals while putting in place the transformational measures necessary to ensure that our longer term climate change objectives are realized. The Government of Canada is committed to the transformation of our economy. In taking action to achieve this, we believe we will meet our Kyoto target.

Our 2005 Climate Change Plan has a number of objectives:

- to mobilize Canadians in a national effort to enable Canada to respect its Kyoto commitment in the short-term and address the longer term challenge of climate change;
- to facilitate the transformation and sustainability of our economy while maintaining our competitiveness through improved resource productivity; and
- to contribute significantly to cleaner air for Canada's cities and communities, enhanced biodiversity and generally improve quality of life for Canadians.

Our Kyoto commitment will be realized taking into account that the precise challenge it sets for Canada is a function of many variables, such as economic growth and energy prices, that can be estimated but cannot be known with certainty in advance. For that reason, our approach to climate change action is evergreen — it builds on previous approaches and incorporates ongoing evaluation and learning. We will engage provinces and territories, Aboriginal peoples, municipalities, industry, non-governmental organizations, and all Canadians in its implementation so as to maximize the conditions of success, to reflect public input, lessons learned and results achieved. We will make modifications and course corrections as part of this climate change approach over time.

This Plan in itself will not solve climate change, but it will engage Canadians and their governments to make decisions and choices in order to reduce GHG emissions, respect Canada's Kyoto commitment and fight climate change over the longer term. This Plan provides overall direction along with important tools and incentives; it will be up to Canadians whether we reach our destination.

Our climate change Plan is a key component of the Government's broader environmental vision — Project Green. It will address the full spectrum of environmental issues, such as biodiversity, water, contaminated sites and clean air. It will create a set of policies and programs aimed at supporting a sustainable environment and a more competitive economy. The groundwork for Project Green was established by the October 2004 Speech from the Throne and Budget 2005.

The Kyoto Protocol became international law on February 16, 2005.

Climate Change is a Challenge but also an Opportunity

Climate change is the greatest sustainability challenge of our time

The global community has recognized the challenge of climate change and is taking action to fight it. The Kyoto Protocol became international law on February 16, 2005, reflecting a growing consensus that managing climate change is key to the health of our planet, the health of people around the world and future global economic stability and prosperity.

If uncontrolled growth of GHG emissions continues, it will contribute to an expected global temperature increase of roughly 1.5 to 6 degrees Celsius over the rest of this century. This would significantly change the way our planet works. In the Arctic, temperature increases of up to 12 degrees Celcius are possible.

Extreme weather threatens Canadian ecosystems, security and health, and imposes severe costs on key sectors of our economy. Recent events such as the BC forest fires (2003), the Prairie drought (2004), and the Eastern Ontario/Quebec ice storm (1998) have demonstrated how vulnerable communities are to the wide-ranging social and economic impacts of weather extremes and variability. The cost of weather-related disasters in Canada increased significantly during the 1990s. A number of sectors in the Canadian economy — including forestry, agriculture and fisheries — can be easily devastated by climate change-induced weather disasters. Canada's north is particularly vulnerable to climate change, and impacts there are already being observed.

The Inter-governmental Panel on Climate Change (IPCC) was established by the United Nations in 1988 to undertake periodic comprehensive assessments of

the available scientific and socio-economic information on climate change and its impacts and on options for mitigating and adapting to the risks posed by climate change. Evolution in our understanding of the science of climate change can be viewed through the key scientific conclusions from the three IPCC assessments completed to date (see Annex 4):

- In the First Assessment, completed in 1990, experts concluded that emissions from human activities are substantially increasing the atmospheric concentrations of GHGs and that this will enhance the greenhouse effect and result in an additional warming of the Earth's surface.
- The Second Assessment, completed in 1995, put forward new findings, including: GHGs have continued to increase; climate has changed over the past century and is expected to continue to change in the future; and the balance of evidence suggests a discernible human influence on global climate.
- The Third Assessment, completed in 2001, included findings that: there is new and stronger evidence that most of the warming over the last 50 years is attributable to human activities; emissions of GHGs due to human activities continue to alter the atmosphere in ways that are expected to continue to change the climate; and atmospheric climate change will persist for many centuries.

The emission reductions targets agreed to by signatories of the Kyoto Protocol for the 2008–2012 period amount to about a 5.2 percent emission reduction from 1990 levels globally. While this is a good first step, much more needs to be done. Scientists estimate that total global emissions would need to be reduced by 50–60 percent from 1990 levels by 2050 in order to stabilize atmospheric concentrations of GHGs at twice pre-industrialized levels.

The Exeter Conference, held in the United Kingdom on February 1–3, 2005, brought together leading scientists from both developed and developing countries to help inform the climate change discussions at the G8. Scientists discussed the need to think more innovatively about how targets for climate change action could be set in the future, including with respect to adaptation.

Fighting climate change helps build a competitive and sustainable Canadian economy

The clear connection between environmental considerations and economic competitiveness is leading a transformation of the way the global economy works. Countries are integrating both environmental and economic performance in order to position

What are greenhouse gases?

Naturally occurring GHGs include water vapour, carbon dioxide, methane, nitrous oxide and ozone. Certain human activities produce more of these gases and other activities can create GHGs that do not naturally occur.

Carbon dioxide (CO_2): An increasing amount of carbon dioxide is being released by the burning of fossil fuels (coal, oil, natural gas) for industrial purposes, transportation and the heating/cooling of buildings, as well as by deforestation.

Methane (CH_4): An increasing amount of methane is being released from landfills, wastewater treatment and certain agricultural practices, as well as from grazing livestock.

Nitrous oxide (N_2O): An increasing amount of nitrous oxide is being emitted into the atmosphere through the use of chemical fertilizers and the burning of fossil fuels.

The three GHGs that are not naturally occurring, but which are included in the Kyoto Protocol are: hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). These gases are generated in a variety of industrial processes.

What is the greenhouse effect?

The greenhouse effect describes the role of the atmosphere in insulating the planet from heat loss. Small concentrations of GHGs within the atmosphere allow most of the sunlight to pass through the atmosphere to heat the planet. However, these same gases also absorb much of the outgoing heat energy radiated by the Earth itself, and return much of this energy back towards the surface. This keeps the Earth's surface much warmer than if the GHGs were absent. This natural process is referred to as the "greenhouse effect" because, in some respects, it resembles the role of glass in a greenhouse. Without these naturally occurring GHGs, including water vapour, carbon dioxide, methane and nitrous oxide, the average temperature of the Earth would drop from 14 degrees Celsius to minus 19 degrees Celsius and would be unsustainable for life on Earth.

Since the Industrial Revolution, developed countries have produced increasing quantities of GHGs, due to the burning of fossil fuels such as coal, oil and natural gas to drive our vehicles, power our industries and heat and cool our homes. Other human activities, such as the clearing of land for agriculture and urban development and landfilling and other waste disposal methods, are also adding to the concentrations of GHGs in our atmosphere.

As a result, concentrations of carbon dioxide in the atmosphere have increased by over 30 per cent since the Industrial Revolution. Concentrations of methane and nitrous oxide, which are also related to human activities, have increased by about 150 percent and 17 percent respectively during the same period. Increased concentrations of GHGs in our atmosphere are enhancing the natural greenhouse effect, causing the Earth to become warmer.

themselves to improve, or even to maintain, the quality of life of their people and to spur the innovation and creativity needed to drive a competitive and sustainable economy.

As the world moves to address the challenge of climate change, those economies and companies that build environmental considerations into their decisions will ultimately have a competitive advantage. Those that choose to ignore the challenge, and the opportunities it brings with it, risk being left behind. As a result, they will face a bigger, more difficult adjustment in the not too distant future. Canada can and will realize the benefits of being a first mover.

Canada's climate change-related investments to date have delivered energy efficiency, energy conservation and cost savings across the economy. It is estimated that Canadian industry is saving $3 billion per year on fuel costs due to advanced energy management practices. Economy-wide savings in energy costs are about $12 billion per year, relative to what costs would have been had energy efficiency improvements not taken place. Further action on climate change will see these numbers grow.

Timely investments in innovative technologies for energy use and production not only have the potential to reduce our GHG emissions but also can open up economic opportunities:

- Renewable energy, including hydro power and wind, has an important role to play in this transformation. In the case of hydro, we can build on the international leadership of our provincial utilities such as Hydro-Quebec, Manitoba Hydro and BC Hydro while emerging renewables such as wind provide the opportunity to be in the forefront of new economic sectors.
- Ballard Power Systems of British Columbia is a world leader in fuel cell technology and collaborates with vehicle manufacturers such as DaimlerChrysler and Ford. Canadian companies are well positioned to garner a significant share of the global demand for fuel cells, which is projected to be nearly $46 billion by 2011.
- Pumping captured carbon dioxide into oil reservoirs not only represents a significant opportunity to store GHGs underground instead

of releasing them into the atmosphere but also increases the amount of oil production from mature Canadian oil reserves. It is estimated that enhanced oil recovery could increase production from mature Canadian oil reservoirs by between 8 and 25 percent of the original oil in place, increasing potential recovery by between 3 and 9 billion barrels of oil.

- Nearly 70 percent of Canada's coal-fired plants are due to retire by 2020. Investments in clean coal technology today will enable us to replace aging thermal plants with technology that is significantly cleaner, is more efficient and has a lifetime of 40 years.

Investors are increasingly putting a value on environmental responsibility. The Dow Jones Sustainability Index grants membership to top sustainability-driven companies that lead their industries by setting standards for best practice and demonstrating superior environmental, social and economic performance. Canadian companies represented on the Index include Alcan, Ballard, CIBC, Cognos, Dofasco, Domtar, Nexen, RBC, Shell Canada, Suncor, TELUS, TransAlta Utilities and TransCanada Corp.

Climate change investments can also support regional development. Increasing the supply of ethanol and bio-diesel will bring significant benefits for grain-growing regions. For example, Saskatchewan estimates that a 400 million litre per year industry will increase provincial demand for wheat feedstock by just over 1 million tonnes annually, create economic opportunities in rural areas of the province, including spin-off employment in the livestock and other industries, and significantly increase construction activity. Reducing agricultural GHG emissions through advanced farming practices and increasing carbon sequestration in soils through no-till and low-till practices, not only fight climate change but can provide an important source of supplementary income and niche market opportunities for Canada's farmers. Not only can enhanced forest management support conservation of natural spaces and protection of biodiversity, it can offer sustainable development options for many Aboriginal communities.

The investment required to reduce GHG emissions will also result in other benefits for Canada. Events like the Ontario blackout of summer 2003 underscore how interdependent we have become, and how serious the consequences of cascading power outages can be for the economy and national security. Through enhanced incentives for co-generation and other forms of distributed generation, the Government is moving to support the diversification of our power system. Options for strengthening our approach to achieving GHG emission reduction through federal-provincial-territorial partnerships could include projects such as strengthening the national electricity grid, helping to harness Canada's hydroelectricity and other renewable energy potential, supporting Ontario in its commitment to phase out its coal-fired power plants and investing in clean coal.

Climate change action brings cleaner air and enhances the quality of life for Canadians

Because fuel combustion is a primary source of smog-related air pollutants as well as GHG emissions, the measures we introduce for climate change reasons, when designed in a way that incorporates human health and community sustainability considerations, can also contribute significantly to cleaner air in Canada's cities and communities. The result is improved health and quality of life for Canadians as well as cost savings for the health care system. We expect that significant clean air co-benefits for Canadians would result from achieving our Kyoto goals. The activities proposed in this Plan could contribute to reducing the current burden of disease associated with air pollution, which is estimated to contribute to thousands of deaths in Canada each year.

Municipalities that act to reduce emissions through improved public transit deliver multiple benefits through, for example, cleaner air, reduced traffic congestion and more livable and attractive cities. International firms choosing to locate in Canada routinely cite quality of life for their employees as a key consideration in selecting a location for investment.

Climate change investments will result in other environmental benefits such as decreasing the mercury emissions that come from polluting coal power plants located in Canada and other countries. Measures to increase the carbon-storing capacity of

> International firms choosing to locate in Canada routinely cite quality of life for their employees as a key consideration in selecting a location for investment.

our agricultural land and forests will create an incentive to protect our wild spaces, such as wetlands, and our biodiversity. Many of the measures that fight climate change also help green our cities and communities through investment in sustainable infrastructure. The latter, when designed in a way that integrates climate change, human health and community sustainability considerations, can support health objectives in a number of areas, including children's health, mental health, active living and seniors' health.

Investments in science and adaptation are also necessary

Some impacts of climate change are being felt already, and more will come to pass in the future. Investments to assist communities to adapt to climate change impacts are required, especially to safeguard those populations facing higher risk — children, seniors and northern Canadians. For example, the recently released Arctic Climate Impact Assessment report has documented the significant challenges faced by Canadians in the Arctic from the already evident impacts of climate change. They are already finding it difficult to maintain existing cultures, livelihoods and health and well-being.

Planning in Canada for the next International Polar Year 2007–2009 represents a focus of internationally coordinated, interdisciplinary, scientific research and observations aimed at the Earth's polar regions. The proposed complementary work to the Arctic Climate Impact Assessment report will enable nations to make major advances in knowledge and understanding of these high latitudes; provide a legacy of new and enhanced observational systems, facilities and infrastructure for ongoing northern scientific and social studies; and use the new knowledge to implement actions that deal with the impacts of the changing environment in these communities.

In order to protect quality of life in Canada, sustained, effective efforts will be required to reduce GHG emissions and promote effective social adaptation strategies that minimize expected adverse impacts and exploit opportunities for sustainable global health. While there are short term costs to reducing GHG emissions, not taking action would also mean incurring costs — the costs of a changing climate and the need to make evermore dramatic adjustments the longer adaptation is delayed.

In addition, we need to invest further in our scientific understanding of climate change. We need to enhance our climate observation network, strengthen our modeling capacity, and build our understanding of the role of oceans in moderating climate.

Canada is Committed to Multilateral Action

Canada is acting in the context of broad multilateral consensus and effort

There is broad international consensus on the challenge presented by climate change and the types of actions needed to address it. Climate change is a global issue requiring global action — countries need to work in a multilateral fashion. Canada is a strong supporter of the Kyoto Protocol, precisely because it is the only internationally agreed mechanism for reducing GHG emissions and it is clearly in Canada's national interest to be involved. The Protocol is phase one of growing international action. Canada will respect its Kyoto commitment in this first phase, and above all Canada will act to address the longer term challenge.

Different countries have different starting points in their fight against climate change and different strengths to lever in their efforts. The Kyoto Protocol provides for international trading and other flexibility mechanisms to address these differences in capacity and allow countries to benefit from each other's strengths. The Netherlands, other European Union countries and Japan are planning significant investments in the international carbon market to help achieve their Kyoto targets. Canada's participation in the international market will deliver domestic benefits, both economically by showcasing Canadian technologies abroad and environmentally by reducing the mercury emissions that reach our borders from other countries. Canada cannot protect itself from climate change without international action.

Clearly all parties to the Kyoto Protocol share the need to develop new knowledge, cost-benefit analyses and adaptation strategies. The world has credible evidence that climate change is a major challenge, but in terms of how to address this challenge, all countries are still learning with regards to the best solutions. That is why both the global approach to climate change and our own domestic approach are designed to build, learn and adapt as we go.

Canada's target under the Kyoto Protocol is to reduce its annual GHG emissions over the period 2008–2012 to a level 6 percent below our actual emissions in 1990

> Our commitment to multilateral action is why we are welcoming the world on November 2005 for the Montreal Conference on Climate.

— a target that is the most challenging among Kyoto signatories (see Annex 3). Despite the challenge, the Government of Canada ratified the Kyoto Protocol because Canada recognizes the significant threat posed by climate change and believes we must share in the international effort to solve this global problem. Moreover, Canada recognizes the domestic benefits that climate change action will deliver — to our environment, our economy and our citizens. This plan takes a more comprehensive approach compared to the national climate change plans of most of the industrialized countries that are Parties to the Kyoto Protocol. In addition, many of our policies and measures are backed up by legislative and financial commitments.

Our commitment to multilateral action is why we are welcoming the world in November 2005 for the Montreal Conference on Climate. This landmark international meeting on climate change is the 11th Conference of Parties (COP 11) and the first Meeting of the Parties to the Protocol (MOP 1). Through this event, Canada will chair the meeting that officially kicks off critical negotiations on how the world will move ahead on climate change beyond the Kyoto period ending in 2012.

Climate Change Actions So Far

We have already taken important steps to build on

Canada has been making significant investments in climate change action since 1998 (see Annex 5). Our efforts to date, including Action Plan 2000 and the *2002 Climate Change Plan for Canada*, have provided a solid foundation for moving forward. This 2005 Climate Change Plan builds on that foundation and will be a living, evolving framework that rewards innovation and success.

Action Plan 2000 put in place a range of programs targeting key sectors across the economy, such as transportation, buildings, renewable energy and cleaner fossil fuels, small and medium-sized enterprises, agriculture and forestry. The *2002 Climate Change Plan for Canada* added further measures.

In 2002, the difference between Canada's projected Business-as-Usual (BAU) emissions and our Kyoto target was estimated to be 240 megatonnes (Mt) of GHG emissions expressed in terms of CO_2 equivalent[1] this basis, the *2002 Climate Change Plan for Canad*a was composed of a range of new initiatives as well as developing a number of options for filling the remaining gap.

The programs set out in the 2002 Plan provide an important part of the foundation for the 2005 Plan. In the 2002 Plan, the estimate of emission reductions associated with these programs was 55–60 Mt. However, given experience over time, as well as a prudent approach to the estimation of emission reductions associated with the Large Final Emitter (LFE) system, it is now estimated that continued funding of these programs would deliver 40 Mt of emissions reductions annually over the 2008–2012 period.

In moving forward, we are building on the *2002 Climate Change Plan for Canada*. Budget 2005 launched a review of existing climate change programming, which is an important part of this Plan's commitment to ongoing evaluation. Programs that are effective will be renewed and extended as appropriate. Some funds will be reallocated, and we will make substantial new investments where it makes sense to do so. In making these decisions, cost-effectiveness, GHG impacts and co-benefits will be key criteria.

The *2002 Climate Change Plan for Canada* also outlined a proposed system of emission reduction targets for Canada's LFEs, which include companies in the mining and manufacturing, oil and gas and thermal electricity sectors. This Plan makes the design of the LFE system a reality, and outlines how emission reduction targets would be set, the mechanisms through which LFEs could meet their targets and the preferred regulatory option for implementing the system.

In the case of the automobile industry, Action Plan 2000 first announced the Government's intent to seek a significant improvement in automobile fuel efficiency. The *2002 Climate Change Plan for Canada* specified that the Government was seeking a 25 percent improvement in fuel efficiency of new vehicles sold in Canada in 2010, equivalent to a 5.2 Mt reduction in GHG emissions. A key component of the 2005 Plan is the agreement reached between the Government and the automobile industry that will result in actions on the part of industry to reduce automobile emissions by 5.3 Mt by 2010.

The *2002 Climate Change Plan for Canada* established a target of 10 percent of new electricity generating capacity to come from emerging renewable sources. Through Budget 2005, this Plan delivers a quadrupling of the Wind Power Production Incentive (WPPI) and establishes the Renewable Power Production Incentive (RPPI). Together these initiatives will allow us to exceed the 10 percent target of the 2002 Plan.

In the agriculture, forestry and landfill gas sectors, the *2002 Climate Change Plan for Canada* proposed to design a framework to enable GHG emission reductions and removals in these sectors to be sold as offsets in an emission trading system. In June 2003, the Government undertook cross-country consultations on the possible design of an offset system, and this Plan provides further detail on how such a system is proposed to work in Canada. As we implement the Plan, the Government of Canada will work with provinces, territories, Aboriginal peoples and stakeholders to confirm the details of offset system design.

[1] A megatonne is one million tonnes of CO_2 or one million tonnes of another GHG expressed in CO_2 equivalent terms.

In many areas, this Plan builds upon our past actions. The One-Tonne Challenge, established in the 2002 Plan as a means of enabling Canadians to take action, is strengthened through this Plan. Partnerships across governments were emphasized in the 2002 Plan, and the Opportunities Envelope and Memoranda of Understanding (MoUs) with provinces and territories were established to that end. In this Plan, through Budget 2005, a much more substantial Partnership Fund will be established to subsume and expand these previous efforts to promote a cooperative approach to climate change action. And this Plan deepens the 2002 Plan commitments by the federal government to take action on climate change within our own operations.

2005 Climate Change Plan

Budget 2005 laid the foundation for our Plan to fight climate change

This Plan builds on the principles set out in Budget 2005 to guide the Government of Canada's environmental investments:

- **Balance**: Investments must balance the need for short-term action to protect our natural environment and long-term measures to spur transformational change in public behaviours and business practices.
- **Competitiveness**: While building sustainable economic growth is an essential component of Canada's long-term international competitiveness, the transition to a sustainable economy must also weigh carefully the impact on short-term competitiveness.
- **Partnership**: To the greatest extent possible, investments in the environment should lever outside funds and encourage responses from industry, citizens and other orders of government.
- **Innovation**: Investments should promote innovation and support new technologies. Innovation feeds economic growth, creates new opportunities and provides long-term improvement in our environmental performance.

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- **Cost-effectiveness**: Initiatives should achieve environmental goals at the lowest possible cost.

Budget 2005 also took an important step in providing resources to the Plan. Funding included:

- **Clean Fund** (renamed the **Climate Fund** in this Plan): a minimum funding of $1 billion;
- **Partnership Fund**: $250 million, with the possibility that funding could grow to $2–3 billion over the next decade;
- **Renewable Energy**: $200 million for the WPPI, $100 million for the RPPI, and $300 million for tax incentives for efficient and renewable energy generation; and
- **Programs**: $2 billion for existing climate change programs.

The Budget noted that more action will be required in the future and that the Government will introduce additional measures as resources permit and as we learn from our domestic investments and international experience.

Our Plan is pragmatic and results-driven

The Plan defines the key measures and institutions that will guide our action, provides necessary incentives and funding and provides for risk management.

A variety of measures are employed, including market-based instruments, different approaches to funding, and regulation. The Plan engages actors across the economy and all levels of government and

a mix of domestic and international actions is proposed.

As the Plan is implemented, we will monitor emission reductions associated with the different elements, as well as the expenditures. Actual expenditures in certain areas could be lower than currently projected, while other mechanisms or programs that perform particularly well could see their funding levels grow significantly over time.

Our Plan will generate beneficial investments across the economy

Examples of beneficial investments include:

- Producers of renewable energy will benefit from the investment in the WPPI program and the RPPI program; these programs may also stimulate related industries in Canada.
- Significant emission reductions and carbon sequestration are expected to take place on farms, likely corresponding to an investment of at least $1 billion.
- Advanced forestry management practices are expected to be associated with an investment of about a quarter of a billion dollars in rural communities.
- Municipalities are expected to produce significant emission reductions through landfill gas capture and use, roughly corresponding to an investment of about a half billion dollars.
- The Plan will facilitate significant investment in major energy infrastructure projects, such as east-west electricity transmission, improved access for distributed technologies like cogeneration and renewable energy, development of clean coal technologies and carbon dioxide capture and storage.

These examples reflect federal initiatives only; they can be expected to increase due to leverage of provincial and private sector funding.

While the Plan focuses on reducing domestic emissions, international investments in emission reduction also have an important role to play. Such investments can be used to lever the penetration of Canadian technologies overseas, bring about environmental benefits that go beyond climate change (e.g., a reduction in mercury emissions that reach our borders) and further our broader national interests, for example, in the area of trade or general sustainability.

> Initiatives are designed to establish Canada as a global leader in the field of environmental technology and thus develop a competitive advantage.

Our approach extends beyond the 2008–2012 Kyoto Period

On the international stage, we will take advantage of the opportunity offered by hosting the Montreal Conference on Climate to be active players in shaping the international agreement after 2012. In determining the specifics of Canada's international negotiation strategy, we will engage provinces, territories, Aboriginal peoples and stakeholders and draw on the advice and expertise of Canadians. We are confident that, with our international partners, we can develop an approach to global GHG emission reductions in the post-2012 period that builds on the strengths of the Kyoto Protocol, draws on our collective experience in fighting climate change since the Protocol was negotiated in 1997 and aligns environmental and economic goals and policy signals.

We are also looking to the post-2012 period in designing our domestic actions. For example, the emission targets for the LFE system (detailed in a later section) that will apply in the post-2012 period will be set through a consultative process. In addition, many of the investments we are undertaking will not only reduce our emissions in the 2008–2012 Kyoto period but also bring about substantial emission reductions after 2012.

As detailed in a later section, the Prime Minister has asked the National Round Table on the Environment and the Economy (NRTEE) to develop advice on a long-term strategic energy and climate change policy for Canada that, among other things, considers options for post-2012 GHG emission reduction targets.

Technology development is a key component of our approach

Encouraging innovation and the development of environmental technology is a key aspect of the Government's approach to climate change in the longer term. Initiatives are designed to establish Canada as a global leader in the field of environmental technology and thus develop a competitive advantage. New technologies can provide Canadians with the ability to reduce GHG and other harmful emissions while enjoying the benefits of a competitive economy.

In recognition of the importance of new environmental technologies, Budget 2005 announced the Government's plan to develop, by the end of 2006, a Sustainable Energy Science and Technology Strategy. The Government will contribute $200 million to the development and implementation of the strategy.

Promoting the development of innovative Canadian technologies is a recurring theme in our Plan. For example, the LFE system, detailed in a later section, sets targets for new facilities based on Best Available Technology Economically Achievable (BATEA) performance standards; in this way, we are taking an approach that builds-in the concept of best technologies available at any given time. Our approach to building strong partnerships with provincial and territorial governments to fight climate change gives a priority to the commercialization and deployment of innovative technologies. Investment in international emission reductions provides significant opportunities to promote the penetration of Canadian technologies overseas.

Our Plan is designed to help achieve key policy outcomes

As well as reducing GHG emissions to respect our Kyoto commitment, the Plan is designed to support the achievement of a number of important policy outcomes:

- competitive and sustainable industries for the 21st century;
- harnessing market forces;
- a partnership among Canada's governments;
- engaged citizens;
- sustainable agricultural and forest sectors; and
- sustainable cities and communities.

These policy outcomes, and the mechanisms in the Plan to achieve them, are discussed below. In putting forward this Plan to address climate change, the Government is focusing on doing the right thing, for the health of the planet and its citizens and the sustainable competitiveness of the Canadian economy.

This Plan requires collaborative action among Canada's citizens, governments, industry, environmental groups and other stakeholders. The Government of Canada will seek to access the knowledge and expertise of Canadians to achieve the intended results. Annex 6 lays out next steps in terms of engagement.

Meeting our climate change challenge

The challenge involved in meeting Canada's Kyoto target is sometimes expressed in terms of an "emissions gap" — the difference between projected BAU emissions in 2008–2012 (i.e., the emissions that would occur in absence of climate change action) and our Kyoto target of 6 percent below 1990 emission levels. Since our emissions in 1990 were about 596 Mt, this means that over the 2008–2012 period our emissions should not, on average, exceed 560 Mt.

Our Plan is not just about reducing GHGs but also about transforming the way our economy currently functions in terms of its impact on the climate.

In 2002, our emissions gap was estimated at 240 Mt. This estimate has now increased — Canada's economy is performing better than had been projected, and economic growth in key emissions-intensive sectors is now expected to be greater than had previously been projected. Between 1990 and 2003, our gross domestic product (GDP) grew by 43 percent, compared with the original forecast of 34 percent. As a result, the emissions gap is more likely in the area of 270 Mt, and could be greater.

The approaches set out in this Plan have the objective of closing our best estimate of the emissions gap. The federal investment required between 2005 and 2012 to undertake this Plan is estimated to be in the range of $10 billion. This includes $2 billion in funding for existing climate change programming. Much of this investment makes sense for reasons beyond climate change, such as helping to provide clean air, enhance industrial competitiveness, technological innovation and economic development, promote energy security and build sustainable cities and communities. Budget 2005 took an important step in allocating $5 billion over the next five years to address climate change and preserve our natural environment.

This Plan outlines a possible allocation of funding to the different elements. While we can establish a clear order of magnitude for overall investment, spending on the individual components will almost certainly differ from the profile laid out in the Plan due to ongoing review and evaluation. Ongoing evaluation and continuous learning may result in changes in investments and in the estimated emission reductions associated with different elements of the Plan.

While there are synergies between the various initiatives in the Plan, we have been careful to avoid double-counting in estimating emission reduction impacts. Our estimates of emission reductions and costs have drawn on a range of reliable sources, including modelling results.

At the same time, it is important to avoid spurious precision in estimating emission reductions and costs. We are making projections seven years into the future, in an area where past experience is not always a useful guide. Moreover, our Plan is not just about reducing GHG emissions but also about transforming the way our economy currently functions in terms of its impact on the climate. Projections, which are inevitably based on past experience, are useful and indeed essential, but they must not be given undue weight. Most countries, in building their climate change plans, have chosen not to engage in detailed, bottom-up, quantitative projections of megatonne reductions. While this is a difficult exercise, it adds discipline and facilitates performance evaluation.

The solution is transparency and continuous learning. Learning will be carried out not just with respect to emission reductions and associated costs, but more generally with respect to our success in transforming our economy consistent with Project Green. The Government will review and reallocate climate change spending on an annual basis to ensure that investments are effective and cost-efficient and result in real and verifiable GHG emission reductions. We will report annually to Canadians on our progress, beginning in 2008.

Building on Canadian experience

Canada has precedents to draw from in embarking on this climate change challenge. A few short decades ago, chlorofluorocarbons (CFCs) were widely used in a host of products across the economy, from refrigerators and air conditioners to asthma inhalers. In the

early 1970s, when science showed that CFCs were destroying the Earth's protective ozone layer, it was clear that urgent global action was needed. Canada and a handful of other countries led the international effort, ultimately resulting in the Montreal Protocol.

At the time, the phase-out of CFCs appeared to be an insurmountable task given technical and economic obstacles. Nonetheless, key industry leaders, facilitated by constructive public policy and citizen action, made breakthrough discoveries leading to new alternatives for CFCs that would not harm the ozone layer such as dry powder inhalers which now replace the old CFC-containing asthma inhalers. These new products and technologies not only have replaced CFCs, but in many cases have also resulted in more effective or energy-efficient products, delivering a double benefit. Today, the Montreal Protocol has 189 countries as Parties and has achieved the almost complete phase-out of CFC production and consumption world-wide.

Canada had a similar experience with acid rain. In the mid-1970s, there was conclusive scientific evidence that acid rain was causing extensive damage to many of the lakes and ecosystems in eastern Canada. Scientists advised that deep reductions in emissions were required to address the problem. In 1985, after more than five years of intense discussion with provinces and industry about the technical feasibility and costs of taking action, the federal government and the seven eastern provinces agreed to targets to cut sulphur dioxide emissions in the eastern provinces in half by 1994.

Canada was more than successful in meeting its target. By 1994, sulphur dioxide emissions in eastern Canada were 54 percent lower than 1980 levels, and today they are 70 percent lower. The innovative technology used by companies, such as INCO in Sudbury, to reduce their emissions has made them competitive leaders in the global base metals marketplace.

A third example is Canada's experience in eliminating the deficit. During the first years of the deficit fight of the 1990s, Canada faced important uncertainties as to the forecasted size of the deficit and the likely effectiveness of measures to address it. Through concerted action, the broad engagement of all citizens and sectors in addressing a common economic challenge, ongoing monitoring of results and continuous refinement of deficit-reduction measures, Canada was able to move beyond these uncertainties and eliminate its federal deficit far sooner than originally thought.

> The Government will review and reallocate climate change spending on an annual basis to ensure that investments are effective and cost-efficient, and result in real and verifiable GHG emission reductions. We will report annually to Canadians on our progress, beginning in 2008.

In these three examples, Canada faced formidable challenges but nonetheless outperformed expectations. In each case, there was a plan to engage Canadians and facilitate achievement of shared objectives. We have every reason to believe that our action on climate change under the Kyoto Protocol will yield the same type of results. These experiences show us that success on climate change will depend less on the precision of forecasts and more on the ability and resolve of governments and Canadians to take action, mobilize around climate change objectives, monitor ongoing progress, recalibrate targets as necessary, quickly apply new knowledge and experience and continuously focus on measures that yield the best results. Most of all, our success in fighting climate change will depend on the innovative spirit and commitment of Canadian citizens, businesses, environmental non-governmental organizations and governments.

> This Plan requires collaborative action among Canada's citizens, governments, industry, environmental groups and other stakeholders.

Elements of the Plan

Competitive and Sustainable Industries for the 21st Century

This Plan is designed to spur innovation and technological advancement, which is essential for the long-term transformation required to maintain a sustainable and competitive economy in the 21st century.

A sustainable economy produces goods and services that meet the demands of the domestic and global marketplace while generating low levels of waste and pollution. This Plan will help position Canada in the emerging world markets by increasing energy efficiency and encouraging greater reliance on renewable energy. At the same time, it will diversify our energy mix and bolster our energy security.

While domestic investments will cut pollution at home and abroad through exports of low-emitting technologies, Canada will work within the Kyoto Protocol framework to promote export of Canadian technologies that support the sustainable development aspirations of developing countries. Canada will do this because it is in our economic interests, and, just as importantly, we will do this because it is essential to achieving our domestic and global climate change goals. Canada will at the same time meet global responsibilities and seize global opportunities.

As noted earlier, a key element announced in Budget 2005 is the development of a Sustainable Energy Science and Technology Strategy. Investments in traditional and new sources of energy and innovative technologies resulting from this strategy and the Plan more generally will provide long-term environmental benefits, while maintaining a competitive and growing economy.

In addition, Budget 2005 made key tax policy changes that will improve productivity while helping businesses make the right environmental decisions, in other words, helping to make it more attractive to move now to make capital investments that will save energy and gain efficiency in the longer run. These enhanced tax incentives will contribute to reduced GHG emissions, better air quality and a more diverse energy supply. Further discussion of these tax changes is set out below in the section on Emerging Renewable Energy. In Budget 2005, the Government also committed to consult on other opportunities to use the tax system to further environmental objectives.

Large final emitter system

Canada's LFEs include companies in the mining and manufacturing, oil and gas, and thermal electricity sectors. These sectors make an important contribution to Canada's economic base, but they are also large contributors to our GHG emissions — just under 50 percent of total Canadian GHG emissions. They must play a significant role in meeting Canada's climate change goals.

The purpose of the LFE system is to secure emission reductions from Canada's largest emitters through a system that is market-based and in line with our policy regarding Smart Regulations. The LFE system will achieve significant reductions in GHG emissions in a manner that supports the continued competitiveness of our industry.

This Plan will help position Canada in the emerging world markets by increasing energy efficiency and encouraging greater reliance on renewable energy. At the same time it will diversify our energy mix and bolster our energy security.

The LFE system will cover about 700 companies operating in Canada; 80–90 of these companies account for approximately 85 percent of the LFE GHG emissions.

The *2002 Climate Change Plan for Canada* proposed an overall target for the LFE system of a 55 Mt reduction from the Business-as-Usual (BAU) baseline emissions projection for 2010 (i.e., the emissions that would occur in the absence of climate change action). The 2002 Plan stated that the system would include a number of adjustments, to address such issues as competitiveness, early action and regional burden. The system was to be implemented through the use of covenants (a system of contractual agreements between government and industry) with a regulatory or financial backstop.

As development of this system took place in consultation with industry over the last two years, it became clear that some sectors, particularly those with fixed process emissions (emissions which are driven purely by underlying chemical reactions and not by fuel combustion) faced competitiveness issues in reducing emissions. It also became clear that the proposed system of covenants backstopped by legislation added considerable complexity to the system.

Approach

The system that is being introduced respects all previous commitments that have been made concerning the LFE system, including that the cost of compliance to industry will not be more than $15 per tonne of carbon dioxide equivalent. Appropriate mechanisms will be implemented to achieve that price cap commitment. A summary of previous commitments and how they are being met is set out in Annex 2.

The description of the LFE system that follows addresses the broad parameters of the system only; elaboration of the system will be undertaken in the coming months in partnership with industry, provinces and territories, Aboriginal peoples and environmental groups, building on the work conducted over the past two years.

Target

In light of experience gained through consultations, the Government has decided to take a streamlined approach to the LFE system. The overall target for the LFE system has been reduced to 45 Mt and will be implemented in an administratively simple manner — there will be no downward adjustments through covenants. As such, the target is firmer.

The 45 Mt target is based on a BAU baseline to which methodological improvements have been made to the electricity component. This 45 Mt target is equivalent to a 39 Mt target using the baseline from the 2002 Plan. Sectoral targets, to be developed by activity on an emissions intensity basis, will be implemented as described below.

In order to establish LFE targets, it is important to take into account two types of emissions: fixed process emissions and all other types of emissions. However, there is a fundamental distinction between these two categories, owing to the fact that the levels of fixed process emissions cannot be controlled by industry, other than by lowering production entirely. By contrast, available technologies do permit industry to reduce other types of emissions without lowering overall production levels. The LFE targets in this Plan address this important distinction.

Total emissions are taken into account in setting the

sectoral targets. Fixed process emissions receive a zero percent target during the 2008–2012 period. All other emissions receive a 15 percent target. However, the targeted reductions from these other emissions as a percentage of total emissions cannot exceed 12 percent of total emissions.

Targets for new facilities and facilities undergoing major transformations will be based on BATEA performance standards. This approach will assist in promoting technological advances and innovation.

LFE companies will have a number of options for compliance:

- Investment in in-house reductions. This is likely to be the first priority of LFE companies, since it allows them to invest in their own facilities and profit from increased productivity and reduced waste associated with such investments in emission reductions and modernization.
- The purchase of emission reductions from other LFE companies that have done better than their target.
- Investment in domestic offset credits (credits attesting that a real emission reduction or carbon sequestration has been generated outside the LFE system — these credits may be purchased by LFE companies and used for compliance with their obligations).
- The purchase of international credits provided that these represent verified emission reductions — i.e., only "green" international credits will be recognized for Canadian compliance purposes. Investment in international credits may be linked to sales of Canadian technology and provides LFEs with experience in an international trading market that is likely to be of increased importance over time.

All of these options will either reduce Canada's own emissions or provide us with qualifying international Kyoto credits that represent verified emission reductions and GHG reductions elsewhere in the world.

It is important to note that the ability of companies to sell surplus emission reductions to other companies (or potentially to the Climate Fund, to be discussed later) provides an incentive for companies to go beyond their target. This is a key reason why early implementation of the LFE system is important, since without it there is much less financial incentive for companies to seek out opportunities to reduce emissions from their operations.

In addition to these options, LFEs would be able to invest in technology developments and count those investments for purposes of compliance. Legislation has been introduced in the House of Commons to establish a Greenhouse Gas Technology Investment Fund. The Fund would support the developments and deployment of innovative domestic technologies that can reduce GHG emissions. For the most part, investments in the Fund would not generate emission reductions until after the Kyoto period of 2008–2012. However, it is important to provide this additional compliance option to LFE companies so as to promote investment in Canadian technology and facilitate Canada's long-term transformational change.

Access to investments in technology development as a compliance option for LFEs would be limited to 9 Mt, meaning that the balance of the LFE target would be met through domestic in-house reductions, domestic offsets and Kyoto credits. Since investments in the Fund are not expected to generate emission reductions within the Kyoto 2008–2012 timeframe, these 9 Mts have not been included in the Plan accounting. Should LFEs invest less than 9 Mt in the Fund or should the Fund's technology investments lead to emission reductions in the Kyoto period, there would be additional emission reductions that are not counted in this Plan.

The proposed legislation establishing the Technology Investment Fund would cap the contribution rate at $15 per tonne for the 2008–2012 period.

Rigorous monitoring and reporting requirements will be put in place to support compliance and public accountability, while protecting the confidentiality of industry competitive practices.

Targets for the period beyond 2012 will be determined in partnership with provinces and territories, Aboriginal peoples, industry, environmental non-governmental organizations, and other stakeholders. Possible criteria that could be used to determine specific longer term targets include:

- consistency with global and Canadian long-term climate change objectives;
- alignment with the proposed National Energy Science and Technology Strategy;
- the aim to make Canadian industry best-in-class;
- Canada's international obligations; and
- recognition of sectoral capabilities and relative compliance costs.

Implementation

The broad parameters of the LFE system are set out above with detailed implementation of the LFE system to be carried out in partnership with provinces and territories, Aboriginal peoples, industry and environmental groups. Our approach builds on extensive discussion with various industry groups, and incorporates a specific proposal developed by the oil and gas industry on implementation of the LFE system. The development of the LFE regulation, beginning in spring 2005, will be the partnership vehicle for further cooperation.

The Government has committed to a regulatory approach to LFE emissions for a number of reasons. The significance of LFE emissions as a percentage of Canada's total emissions makes it critical to Canada's climate change effort that there be certainty about the emission reductions that will result from the LFE system. It makes sense for Canada to build experience with regulatory approaches as partners such as the countries of the European Union are doing. It is through a regulatory approach that LFEs will have access to domestic and international trading and the Greenhouse Gas Technology Investment Fund flexibility mechanisms that will be critical to Canada's innovation and economic competitiveness going forward.

The Government's preferred option for implementing the LFE system is the *Canadian Environmental Protection Act, 1999* (CEPA 1999). Using CEPA 1999 makes sense for a number of reasons. Using existing environmental protection legislation is the most supportive of the Government's policy on Smart Regulations rather than the creation of new legislation. In addition, since CEPA 1999 is already used to control other releases from many of these same sectors, it is administratively more feasible for both government and industry to use it also to regulate GHG emissions.

Rigorous monitoring and reporting requirements will be put in place to support compliance and public accountability, while protecting the confidentiality of industry competitive practices.

A key aspect of CEPA 1999 is its ability to facilitate equivalency agreements with provinces, territories and Aboriginal governments. The Government may conclude equivalency agreements with interested provinces and territories whose legislation and regulation achieves an equivalent environmental outcome. In such cases, there could be an equivalency agreement to the effect that provincial jurisdiction will achieve the same result. An equivalency agreement would have to deliver the performance of the national LFE regulation. It is the Government's intent to make maximum possible use of equivalency agreements in implementing the LFE system.

The Government's working assumption is that CEPA 1999 will be chosen as the legislative vehicle for implementing the LFE system. The Government would regulate under Parts 5 and 11 of CEPA 1999. In order to do so, GHGs must first be added to the list of substances in Schedule 1 to the Act, using the criteria set out in Section 64. International science clearly demonstrates that GHGs meet the second criterion for listing, namely that they constitute a danger to the environment on which life depends.

Some industry groups and provinces have expressed concern over the use of the term "toxic substance" in Section 64 of CEPA 1999. This is a broad-based concern that goes beyond the issue of GHGs. To address this concern and to focus attention on the criteria set out in Section 64, the Government has indicated its support for removing the term "toxic" in Section 64 and related sections of the Act. This ammendment would not alter the manner in which CEPA 1999 is currently administered and is not legally necessary in order to implement the LFE system under the Act.

It is important that implementation of the LFE system be timely, effective and efficient and be carried out in

a transparent manner. The Government will therefore consult Canadians on how CEPA 1999 could be used to implement the LFE system. As a vehicle for consultation, in spring 2005, the Government will release for public review and comment a draft Protocol setting out how CEPA 1999 could be used to implement the LFE system.

It is expected that the draft LFE regulation will be published for public review and comment in fall 2005.

Reductions

The overall target for the LFE system is a 45 Mt reduction from the revised baseline.

Automobile industry

The Government of Canada has been working with the automotive industry to reduce GHG emissions from light-duty passenger cars and trucks. These vehicles account for 12.5 percent of Canada's total GHG emissions and are a significant source of smog and other pollutants that affect the health and quality of life of Canadians.

The Government and the automotive industry have reached an agreement on emission reductions. This agreement will result in actions on the part of the industry to reduce GHG emissions through:

- improvements in advanced vehicle emissions and diesel technology;
- production of more alternative fuel and hybrid vehicles; and
- development and application of high fuel efficiency technologies.

A voluntary approach to emissions reduction in the case of automobile emissions was put forward in the Action Plan 2000; the proposal was given further elaboration in the *2002 Climate Change Plan*. A key consideration in choosing a voluntary approach was that the emissions result from use of a product purchased by Canadian consumers, not from a production process in a Canadian manufacturing facility.

The Government will monitor progress and employ its legislative and regulatory instruments as necessary to ensure achievement of the objectives of the agreement. It recognizes that, from a climate change perspective, it is important to reduce all GHG emissions related to vehicle operation, including tailpipe emissions of carbon dioxide, methane and nitrous oxide, as well as HFC emissions from air-conditioning systems. Rigorous monitoring will ensure that the target is met and that it is met by actions taken by the automobile industry.

In addition to the agreement, the Government has also asked the NRTEE to examine a possible vehicle "feebate," consult, and make recommendations to the Government for the next federal budget. A feebate would provide a consumer rebate for fuel-efficient vehicles and impose a fee on fuel-inefficient vehicles. The program could be designed to be revenue neutral for the Government.

Reductions

The automobile industry has agreed to reduce GHG emissions in 2010 by 5.3 Mt.

The Government proposes to use a variety of mechanisms to promote renewable energy, including production and tax incentives.

Emerging renewable energy

Emerging renewable energy (e.g., wind, solar, tidal power) can make an important contribution in Canada's fight against climate change, moving Canada's electric power generating sector towards lower emissions intensity in the long term, diversifying Canada's energy mix and promoting sustainable economic growth.

The Government proposes to use a variety of mechanisms to promote renewable energy, including production and tax incentives.

Budget 2005 provided greatly expanded incentives for renewable energy. The WPPI first introduced in Budget 2001, was quadrupled in Budget 2005 which allocated $200 million over five years to this popular program. This increases the target for new wind generating capacity to 4000 megawatts (MW), or the amount of power needed annually by approximately 1 million average Canadian homes. There will be no provincial caps or limits on project size, but there will be provisions to assure minimum access to the program for each province.

The expanded WPPI establishes the critical elements for Canada to realize the full potential economic benefits of a growing wind power industry. In addition to the environmental benefits, this initiative will support rural economic development, build a new economic sector and position Canada to be a leader in a vibrant wind energy industry in North America and internationally.

In addition to wind resources, many other forms of renewable energy are available in Canada. The competitiveness of renewable energy technology has improved in recent years as a result of technological developments and the increasing cost of more conventional technologies. There is an increasing need for these sources of power to meet growing electricity demand, while reducing impacts on the environment.

Therefore, in Budget 2005, the Government introduced the RPPI, with an investment of $97 million over five years, to support other renewable energy sources including small hydro, biomass, and tidal power. RPPI builds on the successful

WPPI program and is targeted to lead to 1500 megawatts (MW) of capacity. The incentive will result in more investment in renewable energy projects in all regions of Canada and will help to diversify Canada's energy mix. Projects that receive WPPI or RPPI may also be eligible for the offset system.

Budget 2005 also built on existing tax measures to encourage Canadian businesses to invest more in energy efficiency and renewable energy generation. It increased capital cost allowance from the already very favourable 30 percent to 50 percent for highly-efficient cogeneration equipment and the full range of renewable energy generation equipment currently included in Class 43.1 of the *Income Tax Act* (including wind turbines, small hydro facilities, active solar heating equipment, photovoltaics and geothermal energy equipment).

Allowing tax deductions for capital cost to be taken more rapidly will improve the after-tax return on these investments. The resulting financial benefit will support additional investments in technologies that contribute to a reduction in GHG and other harmful emissions and a more diversified energy supply. This enhanced treatment will be in addition to support available under WPPI and RPPI.

One important opportunity for deployment of cogeneration is in district or community energy systems, where heat or steam is produced in a central generating plant and distributed through a system of pipes to a district of nearby buildings. Budget 2005 extends Class 43.1 to include distribution assets of district energy systems such as pipelines,

In addition to wind resources, many other forms of renewable energy are available in Canada. The competitiveness of renewable energy technology has improved in recent years as a result of technological developments and the increasing cost of more conventional technologies.

pumps and meters where the heat energy has been produced using cogeneration equipment that qualifies for Class 43.1 treatment. These initiatives support private investment in district energy systems and complement the *New Deal for Cities and Communities*. Complementary support for cogeneration through the Climate Fund would make the Budget 2005 provisions all the more effective.

Accelerated capital cost allowance will also be extended to include certain equipment used to produce biogas (largely methane) from anaerobic digestion of farm manure, where the biogas is used to generate electricity. The use of biogas — a renewable energy source — to produce energy helps to reduce fossil fuel use, harmful emissions and agricultural pollution, as well as provide a new source of fertilizer.

The Government will also make qualifying start-up expenses of projects using these additional technologies eligible for treatment as Canadian Renewable and Conservation Expenses.

The Government will continue to review other investments for inclusion under Class 43.1 to ensure that appropriate incentives are provided for investment in efficient and renewable energy generation equipment.

Budget 2005 also undertook to actively consider other opportunities to use the tax system to support environmental objectives, in areas where it would be an appropriate instrument. It set out a framework and general criteria that may guide this assessment. Emission reductions from this exercise are not counted in this Plan.

Reductions

It is estimated that the combination of federal support through WPPI, RPPI, Budget 2005 tax incentives and other initiatives, as well as supportive provincial actions through measures such as renewable portfolio standards, could lead to renewable energy contributing about 15 Mt of reductions annually in the 2008–2012 period.

Harnessing Market Forces

Market mechanisms will be used to tap GHG emission reduction potential across the economy.

The Climate Fund established in Budget 2005 is a market-based, results-oriented mechanism to encourage emission reduction initiatives. Creation of this transformative institution is the single most important distinguishing feature between this Plan and the Government's past approaches to climate change. This Government believes that market-based approaches are critical to integrating climate change considerations into the day-to-day decisions of Canada's citizens and businesses and unleashing the power of innovation so as to move Canada towards a low-emissions trajectory.

Climate Fund

The purpose of the Climate Fund is to create a permanent institution for the purchase of emissions reduction and removal credits on behalf of the Government of Canada, which will be one of the primary tools for Canada's approach to climate change.

By tapping the potential of the market, Canada will:

- stimulate innovation;
- enable Canadians to take action;
- encourage energy efficiency;
- deliver cost-effective reductions and sequestration;
- drive the adoption of best available technologies; and
- stimulate the development of a domestic emissions trading system.

The Climate Fund will be results-based, with a focus on real and verifiable emission reductions.

Approach

Announced in Budget 2005, the Climate Fund will purchase domestic emission reductions and, in those cases that are demonstrably in the national interest, international reductions that are recognized under the Kyoto Protocol. It will make its purchases through a competitive process.

In a timely fashion, the Government will consult with Canadians on the specifics of how the Climate Fund may best achieve its mandate.

Domestic reductions

As a first step, individuals and organizations planning to substantially reduce or sequester emissions will apply to an offsets body under the authority of the Minister of the Environment to have their projects recognized as eligible for domestic offset credits. Once the emission reductions have occurred, this separate body will award credits for reductions. Opportunities for reduction and sequestration will be available across the economy. Potential examples include:

- farmers who adopt low-till or zero-till practices;
- forestry companies that engage in state-of-the-art forest management practices;
- property developers that include district heating and renewable energy elements in their plans for new sub divisions;
- businesses that develop innovative ways to reduce emissions through recycling and energy efficiency;
- companies and municipalities that invest in their communities by encouraging alternative transportation modes;

- municipalities that capture landfill gas and use it to generate electricity;
- large emitters that do better than their regulated emission targets;
- new electricity generation projects that lead to incremental GHG emissions displacement;
- remote communities that convert electricity generation from diesel to renewable resources; and
- companies and their employees that pool collective emission reductions from activities such as tele-commuting.

The Fund will contribute to Canada's sustainable competitiveness by encouraging Canadians to seize cost reducing opportunities across the entire economy.

As a second step, credits that have been issued for qualifying projects will be purchased by the Fund pursuant to a competitive process and retired on behalf of Canada's commitment to Kyoto.

There will be a minimum project size for qualifying emission reductions or carbon sequestration, so as to ensure that administrative costs do not outweigh the value of the environmental benefit.

The Fund will also engage in advance purchase of emission reductions from large strategic projects in partnership with the private sector. For example, projects that have the potential of generating significant GHG emissions in which the cost per tonne is initially high but is expected to fall over time could be considered if the project would contribute to the structural change necessary to move Canada to lower carbon intensity over the longer term. Conditions around advance purchases will be set so as to require

What is an offset credit?

Projects that result in emissions reductions or sequestration could earn offset credits.

- **Reductions** occur when emissions released into the atmosphere by a source are decreased. For example, property developers that include district heating and renewable energy elements in their plans for new sub-divisions could earn offset credits for the resulting emission reductions.
- **Sequestration** occurs when emissions in the atmosphere are trapped in a sink. For example, farmers who adopt low-till or zero-till practices or forestry companies that engage in state-of-the-art forest management practices could earn offset credits for the resulting sequestration.

Individuals and organizations that reduce or sequester emissions will be able to apply to a body under the authority of the Minister of the Environment for offset credits. To qualify for credits, certain criteria established by the Minister would have to be met. For example, emission reductions would have to go beyond BAU practices, so that offset credits are not awarded for reductions that would occur in the absence of the offset system.

Verification of projects against the criteria will be carried out and credits will be issued for qualifying reductions. Aggregation and verification of these reductions will be provided by all manner of actors in the economy, from municipalities to industry associations to private sector brokers and auditors.

Individuals or organizations awarded offset credits have a few options. They can retire their credits, helping Canada respect its Kyoto commitment, or they can sell them. Buyers would include companies facing emission reduction targets under the LFE system, who could use the credits to comply with their targets. The Climate Fund will also purchase offset credits through a competitive process and retire them, helping Canada respect its Kyoto commitment.

The Government will be consulting Canadians on the proposed rules for offset credit creation in the coming months.

repayment to the Fund should the associated GHG emission reductions not be realized.

Projects that receive funding from the Climate Fund may also be of interest to the Partnership Fund (see page 25) and the Greenhouse Gas Technology Investment Fund, allowing synergies to be realized between the different mechanisms. A monitoring program will be implemented to ensure that there is no double-counting of tonnes.

Legislation has been introduced in the House of Commons to establish the Fund. Aspects of the Fund's mandate, such as how to ensure benefits to Canada from investment in international emission reductions, will be put forward for public review and comment in spring 2005. At the same time, the proposed criteria to be used in reviewing projects will be published. Project reviews, and the registration of eligible projects could begin as early as fall 2005, the same timeline that applies to the selection and initial signing of contracts for projects generating Kyoto credits. Initially, priority could be given to project types where quantification methodology is well advanced, such as afforestation, agricultural sinks and landfill gas capture projects.

International investments

The Climate Fund's primary mandate is to promote domestic GHG emission reductions, with a view to positioning Canada to compete in the 21st century carbon-constrained global economy. The Fund will also invest in internationally recognized Kyoto emission reductions through the Clean Development Mechanism

and Joint Implementation, as well as through procedures for "greening" other international credits. Only "green" credits — i.e., credits that represent real and verified emission reductions — will be recognized; there will be no purchases of so-called "hot air."

Investment in international emission reductions will be undertaken in a manner that advances Canada's broader sustainability interests. Specifically, investment in international emission reduction projects would have at least one of the following characteristics:

- apply Canadian technology;
- improve Canada's international competitiveness;
- expand Canada's trade or otherwise advance our national interest (e.g., deliver environmental benefits by reducing the mercury that reaches our borders); and
- advance Canada's international development objectives.

In the initial years, Fund purchases will primarily be directed to domestic projects. During this period, participation in the international market will take the form of purchases from emission reduction projects in developing countries and some purchases of options for future investment in "greened" credits. It is expected that the Fund's participation in the international carbon market will evolve over time, as we gain experience and our domestic climate change regime develops.

To facilitate the process of international purchases, the Government may develop MoUs with countries of interest. The "greening" of any international credit purchases would be governed by a bilateral agreement between the government of Canada and the seller country in which Canada would want to ensure both environmental benefits and trade benefits for Canadian companies. Such agreements would ensure environmental benefits by stipulating that 100 percent of the proceeds from the purchase must be reinvested in projects and activities that contribute to GHG emission reductions in the seller country.

Reductions

Budget 2005 provided minimum funding of $1 billion. It is estimated that the Climate Fund could yield in the order of 75–115 Mt of reductions annually in the 2008–2012 period, with funding in the order of $4–5 billion.

It is not possible to predict how many of these reductions will occur domestically. The Climate Fund will give a priority to domestic emission reductions. However, the amount of domestic emission reductions that will be realized depends on many factors, including: the entrepreneurial spirit of Canadians and their interest in finding innovative means of reducing emissions; the success of the Climate Fund in tapping into that spirit of entrepreneurship and innovation; how "market friendly" are the rules for domestic offset creation; and the economic and fiscal circumstances at that time. The Government has great confidence in the innovative spirit of Canadians; a great deal of interest is already being expressed with respect to the Climate Fund.

The Climate Fund will also invest internationally. However, just as it is not possible to predict the scale of domestic emission reductions, it is not possible to say at this point how many international reductions Canada may seek to purchase.

International trading market for carbon

Canadian investment in international emission reductions can be an important vehicle for the promotion of Canadian technologies. International trading in GHG emission reductions is expected to become a feature in global efforts to combat climate change. It should be noted that a tonne of GHG emissions reduced anywhere in the world contributes to the global climate change challenge. The Climate Fund's participation in the international carbon market will provide Canada with both environmental and economic advantages.

From an environmental perspective, the Fund will purchase from projects that use technologies that deliver co-benefits — i.e., that not only reduce GHG emissions, but also reduce other harmful emissions. For example, mercury emitted from coal-burning power plants in other countries leads to serious health and environmental impacts on Canada. Canadian investment in cleaner energy generation overseas might therefore provide multiple benefits to Canada.

From an economic perspective, Canada will use these international investments to develop and deploy its expertise in the field of environmental services and technologies. The international market for climate change technologies is growing quickly. Government investments in international credits will give Canadian innovators early and supported exposure to identify and develop technologies with strong international applications. This type of assistance is often all that is required for a promising technology to reach a stage at which it is competitive on its own.

Projects in the areas of renewable energy, biogas capture, clean coal, carbon sequestration, pipeline retrofits and efficiency and conservation projects can demonstrate Canadian goods and services and increase field experience in foreign markets.

Investment in international emission reductions, in conjunction with or parallel to addressing climate change impacts, can also advance development objectives. Developing country GHG emissions are expected to surpass industrialized country emissions in the coming decades; a combination of technology transfer and development assistance is needed for the sustainable development of these countries. This approach was key to the success of the world's efforts to address the depletion of the ozone layer. In the climate context, these strategies would reduce GHG emissions, promote sustainable development, and prevent thousands of premature deaths from air pollution in developing countries.

In addition to these immediate economic and environmental benefits to Canada and development benefits, the experience acquired by the Climate Fund in international trading for carbon emission reductions will position Canada to influence and benefit from the future evolution of the market.

Similarly, the experience gained by Canada's LFEs in international carbon trading will prove advantageous in the post-2012 period.

A Partnership among Canada's Governments

Recognizing the necessity of cooperative action, this Plan will leverage investments across all orders of government to realize success in our fight against climate change.

Climate change is a challenge that affects all jurisdictions, and so our response must be a national one that reflects our federal structure. This means a joint effort, with all orders of government — federal, provincial, territorial and municipal — working together within their own areas of responsibility to make a contribution and deliver a harmonized approach.

Partnership Fund

Canada's provinces and territories play a fundamental role in achieving climate change goals. The *2002 Climate Change Plan for Canada* made a good start in developing effective federal-provincial-territorial partnerships. Pursuant to the 2002 Plan, Budget 2003 provided $160 million for an Opportunities Envelope to fund emission reduction projects of interest to federal, provincial and territorial partners. We have also initiated MoUs with interested provinces and territories.

However, much more is needed to maximize the potential of partnerships with provinces and territories and with Canada's industry. Enhancing these efforts is critical to Canada's success in transforming our economy, fighting climate change and protecting our environment. The Partnership Fund will be the key vehicle to do that.

Approach

The Government of Canada will strengthen its partnerships with provinces and territories.

MoUs will be developed where none currently exist and MoUs that are already in place will be enhanced. These agreements will focus on achieving Canada's climate change goals in the short and long term, as well as bringing about the transformational changes necessary for ensuring the competitiveness of the Canadian economy in the 21st century. They will identify goals and strategies for key sectors of the economy in each province and territory and areas of synergy and collaboration among provinces, territories and with the federal government. Examples of such synergies include the setting of building codes by provinces and appliance standards by the federal government.

Newly created in Budget 2005, the Partnership Fund will support these government-to-government agreements through cost-sharing. Through the Partnership Fund, the Government will invest in technologies and infrastructure development that are important to both orders of government, such as clean coal technology. Nearly 70 percent of Canada's coal-fired power plants are due to retire by 2020. Clean coal technology offers the potential to reduce a plant's emissions significantly over its 40-year lifetime. To ensure that we can achieve these reductions in the future, it is critical that investments in clean coal technology are made today. Other strategic investments could include a carbon dioxide capture and storage pipeline, cellulosic ethanol plants, east-west electricity transmission grids and other options related to the phase-out of coal-fired power plants. The Fund will also explore options for more efficient integration of intermodal freight transportation.

These investments in major projects are expected to contribute significant emission reductions in the Kyoto period. Some projects are likely to deliver the greater

> Canada's provinces and territories play a fundamental role in achieving climate change goals.

part of their emission reductions after 2012. Priority in investments under the Partnership Fund will also be given to projects that will deliver reductions in the 2008–2012 period.

It is expected that, under the Partnership Fund, investment will also be made in smaller projects of a local nature, including, for example, the cost-sharing of climate change centres in each province and territory along the lines of Alberta's Climate Change Central. It could also support national strategies in areas such as demand-side management, conservation and combined heat and power (cogeneration).

To ensure that emission reductions are incremental, the Partnership Fund will be coordinated with existing complementary federal climate change measures, such as the Climate Fund and the Green Municipal Funds, and with other federal investments expected to contribute to climate change, such as the *New Deal for Cities and Communities*. An important thrust of the Fund will be enhanced synergies among provinces and territories in fighting climate change. The Partnership Fund would subsume and expand the current Opportunities Envelope.

The Partnership Fund will also support partnerships between governments and Canadian industry on major emission reduction projects. It may also work together with the Climate Fund and Technology Investment Fund in supporting certain projects.

Reductions

Budget 2005 provided funding for the Partnership Fund of at least $50 million per year for the next five years, with amounts to be augmented as projects are identified and developed. It indicated that funding could grow to $2–3 billion over the next decade.

The amount of emission reductions that may be generated through the Partnership Fund will depend on the level of federal funding, the willingness of provincial and territorial governments and the private sector to enter into partnerships, and the availability of innovative projects. It is estimated that with federal funding in the order of $2–3 billion and with the leverage it could create with other sources of funds, the Partnership Fund could yield GHG emission reductions of 55–85 Mt annually in the 2008–2012 period.

Greening Government

In order for the federal government to be a true partner with other orders of government, and indeed with Canada's citizens, it must demonstrate leadership in climate change action. Major steps have already been taken. The Government builds all its new facilities to be 25 percent more energy efficient than the existing Model National Energy Code for Buildings. Government has committed to retrofitting a further 20 percent of its commercial buildings by 2010 to improve energy efficiency, financed through energy cost savings.

To date, 7,000 federal buildings — about 30 percent of the federal building stock — have undergone energy audits under the Federal Buildings Initiative. The follow-up work undertaken has resulted in a total savings of $27 million a year on energy bills and a reduction in GHG emissions of 20 percent on average. Important steps have also been taken to reduce GHG emissions from federal vehicles and to engage employees in reducing emissions in their everyday actions.

Approach

The Government of Canada will build on its achievements to date by ensuring that its internal operations are among the "greenest" in the world. The federal government spends over $13 billion per year on goods and services and will use this purchasing power to demonstrate leadership in climate change action. The Government will implement a new Green Procurement Policy to govern its purchases by 2006.

Green Procurement, including life cycle costing, will be a priority and will include purchases of energy, in

particular electricity; purchases of other goods and services, such as automobiles; and investments in new fixed assets, such as buildings.

The federal government will seek innovative means of modernizing its central heating and cooling plants with increased involvement of the private sector. This modernization is key to further reducing the GHG emissions of its office-building inventory. The Government will also explore partnerships with the private sector and other stakeholders to access innovative technology for this project and leverage its investment to benefit the broader community, including possible participation in community energy system projects.

To lead by example and encourage a focus on sustainability in the Canadian marketplace for real property, the Government will ensure that as of 2005, the construction of new government office buildings will be funded to meet the Leadership in Energy and Environmental Design Gold standard. Buildings meeting this standard use, on average, slightly over one-half of the energy required by the average equivalent office building currently in the Government's inventory. This standard will also be sought in the case of new long-term leases.

The Government will also take a series of measures to ensure that its fleet of vehicles is among the greenest in the country, including:

- replacing its vehicles more quickly and choosing more efficient models;
- significantly increasing its purchase of hybrid vehicles and vehicles that operate on E85 and other alternative fuels; and
- adopting more stringent user practices such as anti-idling and vehicle sharing.

Provincial, territorial and municipal governments also have similar initiatives to reduce GHG emissions from their operations. All governments of our federation will learn from each others' experience in this area. To the extent that GHG emission reductions will occur as the result of actions from provincial, territorial and municipal governments, they are not counted in this Plan.

Reductions

Total federal emissions are about 3 Mt annually. The Government is setting a target to reduce these emissions by 1 Mt annually over the 2008–2012 period, to be funded primarily through internal reallocation.

Engaged Citizens

A sustainable environment is important to Canadians, and this Plan will provide citizens with the tools they need to take action.

Together, individual Canadians are responsible for 28 percent of Canada's GHG emissions. On average, each Canadian produces 5 tonnes of GHGs annually. Therefore, their buy-in and active involvement are critical if we are to achieve our climate change and sustainability goals.

Canadians need to take action themselves and can play an important role in driving sustainability improvements in communities and industry. In the longer term, increasing the awareness of Canadians will help to create a generation that understands and embraces sustainability.

One-Tonne Challenge

To date, initial steps have been taken to engage Canadians in the One-Tonne Challenge, a public education program launched to challenge Canadians to reduce the 5 tonnes of GHGs each citizen produces annually to 4 tonnes. These steps are focused on:

Information Products & Tools: An on-line GHG calculator helps Canadians determine their current emissions and build 1-tonne reduction plans.

National Awareness: A major national advertising campaign on television, print and radio encourages Canadians to get a copy of the Guide so that they can take part in the Challenge.

Communities: More than 40 communities are rolling out Community Challenges involving more than 200 organizations and local governments. They are engaging individuals in reducing GHG emissions and making local investments to create healthier, more sustainable communities for all their citizens.

Youth: A network of youth organizations has created a youth version of the One-Tonne Challenge and is working with youth across the country on local emissions reduction or education projects.

Educators: Expert teachers from across the country are helping to create lesson plans and other web based resources on climate change that will be accessible to all educators.

Private Sector: Retailers are linking the marketing of energy-efficient products to the One-Tonne Challenge goal. Many employers are creating Challenges targeted to their employees.

Consumers: The "*Guide to the One-Tonne Challenge*" provides more than 20 pages of tips to consumers for saving money (and reducing GHG emissions). This includes an EnerGuide for Houses audit, which can lead to savings of 20–35 percent on heating bills. In addition, tips are provided for reducing costs at the gas pump by driving more efficiently, selecting a fuel-efficient vehicle or keeping vehicles tuned. Through a searchable database on the One-Tonne Challenge web site, consumers can find out about the current rebates and incentives available to them from all orders of government to reduce GHG emissions.

While a good start has been made, more needs to be done.

Approach

The One-Tonne Challenge will build on work to date to increase awareness, knowledge, commitment and action by Canadians. In particular, we will work with partners in communities, youth groups, private sector and educators to provide real opportunities for Canadians to make lifestyle changes and informed purchases to reduce individual emissions by at least 20 percent. National promotion will focus on improving access for Canadians to programs and services from all orders of government that provide them with consumer information, technical advice and incentives for action.

Canadians need better information to allow them to make informed decisions about products they are considering. Product marks such as ENERGY STAR®, EcoLogo^{M} and EnerGuide will be a focus of point-of-sale and other promotions to help Canadians in their search for greener products. Government, through partnerships with retailers and utilities, will also build consumer confidence in green products and green power.

The One-Tonne Challenge program will actively promote opportunities presented by the Climate Fund.

Vehicle fuel efficiency improvements provide a significant opportunity for partnerships with vehicle

Canadians need better information to allow them to make informed decisions about products they are considering.

manufacturers and dealers. The One-Tonne Challenge will work with these groups to ensure that Canadians have the information and tools they need to make informed purchases and operate their vehicles in the most efficient way.

Partnerships with provinces and territories, including new investments in regional Climate Change centres, shared delivery of Community Challenges, co-promotions to help increase transit ridership, and joint efforts to increase the capacity and provide support to environmental groups to help deliver GHG emission reductions, will bring programs and services closer to the individuals who need them. Climate Change Centres for example, will provide emission reduction expertise, technical advice and service to individuals, local business and communities.

Climate change centres will also provide regional capacity for the Federation of Canadian Municipalities' Partners for Climate Protection Program. The Federation of Canadian Municipalities will still need to play an important role at the national level in recruitment, coordination and recognition and will receive support to do so for at least the next five years.

When it comes to small and medium-sized enterprises, the Government of Canada will build on a successful model developed by Environment Canada in Quebec. The model is Enviroclub, which helps company managers in small and medium-sized enterprises to better understand the profitability advantages of environmental management and provides hands-on experience by taking on a pollution prevention project within each of their plants.

The 41 community challenges under way will continue to be supported over time to allow them to make substantive gains in GHG emission reduction and to learn collectively the most effective interventions when it comes to engaging consumers in the challenge.

At least 20 additional community challenges will be supported, and longer term investments will be made in those already under way.

We will engage Aboriginal and northern communities in climate change activities and undertake specific initiatives to address GHG emission reductions.

In sum, what is being launched is a strengthened and more focused public engagement effort that will help move Canadians from concern to action.

Reductions

The challenge to Canadians will be to collectively generate 5 Mt in incremental reductions annually over the 2008–2012 period. Additional funding of $120 million would be provided to bring this about.

Programs

Climate change programs have an important role to play in generating emission reductions, promoting early action, improving our understanding of climate change and laying the groundwork for long-term behavioural, technological and economic change.

Since 1998, the Government has made incremental investments in climate change though successive

budgets. These investments, touching all sectors of the economy, were aimed at the "low hanging fruit" — those measures that put us on the path to emission reductions at the lowest cost. Of the $3.7 billion set aside in previous budgets for climate change, approximately $700 million remains unallocated, while a further $1.1 billion of the funds allocated is intended for use in the coming fiscal years.

Approach

In moving forward, the Government will learn from past investments.

As indicated in Budget 2005, the Government will undertake a comprehensive review of existing programs to determine which programs should be maintained or expanded, which programs should be modified and which programs have been performing below expectations or have outlived their usefulness and so should be terminated. Savings in terms of funds previously allocated will be redirected. A key criterion for a program to continue will be its ability to deliver cost-effective emission reductions over the short and long term.

Some programs have already been identified as clearly successful and will continue or be expanded. For example, Budget 2005 invested $225 million over five years to quadruple the number of homes retrofitted under the successful EnerGuide for Houses Retrofit Incentive, from 125,000 to 500,000. This program is designed to help homeowners reduce their energy consumption by offering grants for people who improve the energy rating of their houses.

In the transportation sector, we have a range of programs aimed at encouraging private motorists to develop energy-efficient purchase, use and maintenance practices. Key components include the EnerGuide fuel consumption label and the annual Fuel Consumption Guide, which provides fuel consumption data for new light-duty vehicles, as well as the Idle-Free Campaign, which seeks to curb vehicle idling. These initiatives help individual Canadians understand how their automobile purchase decisions and driving habits affect climate change and the environment.

Another program that has clearly demonstrated its value is the Green Municipal Funds, which directs funding to municipalities for innovative sustainability projects. Thus far, the Green Municipal Funds have been effective in stimulating community-based feasibility work and green infrastructure investments, contributing to more than 340 projects across the country. Budget 2005 allocated $300 million for the Green Municipal Funds ($150 million of which will be used to help communities remediate and redevelop brownfields, which are abandoned sites where environmental contamination exists).

New programs will be introduced where a clear rationale exists, including a demonstration that the objective can be best accomplished through a program rather than a market mechanism such as the Climate Fund.

Reductions

Budget 2005 provided $2 billion for existing climate change programs. It is estimated that continued funding of these programs through 2012 could yield up to 40 Mt of GHG emission reductions annually in the 2008–2012 period. There is no overlap between the emission reductions expected to be generated from these programs and our LFE target.

Sustainable Agriculture and Forest Sectors

This Plan recognizes our abundant forests and agricultural land as national advantages that Canada has in our fight against climate change.

This Plan recognizes our abundant forests and agricultural land as national advantages that Canada has in our fight against climate change.

Sinks occur when GHG emissions are removed from the atmosphere and stored elsewhere, such as in forests or agricultural soils. Sinks are an important component of Canada's overall approach to climate change and also contribute to biodiversity and conservation objectives. In the international negotiations on Kyoto, Canada received recognition for the contribution its ongoing practices make to biological carbon sequestration — this contibution is commonly termed BAU sinks and is counted towards our Kyoto target.

Approach

By definition, BAU sinks are the result of the continuation of existing practices.

However, it is estimated that Canada's biological sinks can play a much greater role in fighting climate change. Biological carbon sequestration beyond BAU levels will be incented through the Climate Fund and through Government initiatives aimed at protecting ecological lands. It is estimated that the potential for beyond BAU agriculture and forest sinks is in the order of 15–20 Mt. How best to measure and incent incremental carbon sinks will be determined in partnership with the provinces, territories, Aboriginal peoples, farmers, forestry companies and other stakeholders.

These measures will also allow us to gain significant co-benefits from carbon sink enhancement, including conservation of natural habitat and preservation of Canada's biodiversity.

Organizations such as the BIOCAP Canada Foundation, a national not-for-profit research foundation, play a very important role in advancing our understanding of the role of our natural resources in climate change.

Reductions

In agriculture, BAU practices are predicted to generate a carbon sink of 10 Mt in the Kyoto commitment period of 2008–2012. An incremental sink of 16 Mt or more beyond BAU levels may be possible through practices such as reduced tillage, less summerfallow and increased use of forage which could be incented through the Climate Fund. Incremental emission reductions from agriculture could result from activities such as beef feeding strategies and hog manure management.

With respect to forestry, the projection in the *2002 Climate Change Plan for Canada* was that existing forest practices would result in a BAU carbon sink of 20 Mt. Federal and provincial governments are currently working towards a revised estimate; that estimate could fall to zero as a result of the Mountain Pine Beetle infestation and forest fires in British Columbia. An incremental sink of 4 Mt beyond BAU levels may be possible through practices such as afforestation, reforestation and avoided deforestation which could be incented through the Climate Fund.

Sustainable Cities and Communities

This Plan recognizes the synergies between the parallel efforts of fighting climate change and greening our cities and communities.

A large portion of GHG emissions — as well as the opportunities to reduce them — are directly or

This Plan recognizes the synergies between the parallel efforts of fighting climate change and greening our cities and communities.

indirectly associated with urban regions. As of 1990, municipalities directly controlled about 38 Mt of GHG emissions.

The Government of Canada's *New Deal for Cities and Communities* will help advance climate change goals.

Approach

The New Deal includes a targeted gas tax transfer of $5 billion of federal funds over five years to support environmentally sustainable infrastructure. This will help to reduce Canada's GHG emissions and encourage more efficient use of energy through investments in sustainable infrastructure such as landfill gas capture, community energy systems, solid waste management, capacity building, and especially public transit, which is a key focus of the New Deal where investments will make gains in the areas of climate change, smog and congestion in our urban centres.

The New Deal aims to transform how infrastructure investments are made in our cities and communities, by providing an outcomes-driven vision for community and city sustainability. The gas tax transfer will support capacity building to enable municipalities to develop and implement long-term, integrated sustainable plans, focused on the achievement of commonly-defined sustainability outcomes.

Budget 2005 committed to renew the Canada Strategic Infrastructure Fund, the Municipal Rural Infrastructure Fund and the Border Infrastructure Fund. The Government's infrastructure programs contribute towards environmental sustainability, including reducing GHG emissions. For example, in total across Canada, a minimum of 60 percent of funding under the Municipal Rural Infrastructure Fund, with a minimum of 40 percent per jurisdiction, will target "green infrastructure" that provides a better quality of life and promotes sustainable development.

The Partners for Climate Protection program includes more than 120 municipalities committed to GHG emission reductions. In addition, InfraGuide, a series of infrastructure best practices funded by Infrastructure Canada, develops best practice tools that can be used to help municipalities cut GHG emissions and adapt to climate change.

Reductions

While the New Deal can be expected to generate important GHG reductions in the Kyoto period, the magnitude of those reductions will depend on the conclusion of agreements with provinces and territories. Consequently, this Plan does not include those reductions.

Conclusion: **Kyoto and Beyond**

This Plan lays out a set of comprehensive policies and programs that will enable Canada to respect its Kyoto commitment in the short term and will position Canada for the longer term challenge of climate change by mobilizing Canadians in a national effort. It is a Plan that makes sense for Canada's future.

This suite of actions will also advance a number of objectives beyond climate change: cleaner air, a sustainable environment, a competitive and sustainable economy, advancement of Canada's international agenda, green communities, enhancement of biodiversity, preservation of wild spaces and improved health for our citizens.

As a framework, this Plan serves to guide Canada's actions on climate change. Risk management is a key consideration and is provided for through on-going evaluation. Climate change spending will be reviewed and reallocated on an annual basis, to ensure that investments are cost-efficient and result in real GHG emissions reductions.

This plan is comprised of the following key components:

- The Climate Fund is a market mechanism that stimulates innovation, drives the development and adoption of technology, and enables a broad range of action across the economy.
- The Large Final Emitter System, also market-based, is a showcase of smart regulation; it achieves significant reductions from Canada's largest emitters while supporting their continued competitiveness.
- Partnerships with provinces and territories are a critical element of the Plan.
- The automobile industry and the renewable energy industry both play key roles, as do the technologies that provide for carbon sinks.
- Enhancement of tax incentives is an additional way that the Plan uses market forces to provide for economy-wide action.
- The Government of Canada also has a duty to lead by example, and will Green its own operations, and re-align its own programming.

As a next step, the Government will be engaging provinces, territories, Aboriginal peoples and stakeholders on both the overall framework and specific elements of the Plan. Our approach to engaging Canadians is provided in Annex 6.

Science and Adaptation

Climate change is a long-term challenge, and investments in science and adaptation will prepare Canada to meet that challenge.

The science that underpins the Government of Canada's policy on climate change is sound. But more is required as we move forward. Canada's climate observation network will be enhanced to more fully understand changes that are occurring across Canada and in key sensitive areas, such as the North.

Climate change is a long-term challenge and investments in science and adaptation will prepare Canada to meet that challenge.

Regional- and local- scale modelling capacity will be developed to provide more accurate predictions of climate change.

Canada's highly respected global climate model, which drives regional predictions, will remain at the leading edge of science. Investments in science will ensure that sinks, a key element of addressing climate change, are properly understood and quantified. Canada also has a wealth of traditional knowledge to draw upon. We will expand our capacity to transform scientific knowledge into usable information for policy-makers, resource sector managers and the business community.

Finer-resolution climate change information is more suitable for the development of possible adaptation measures, as well as for the assessment of the viability of mitigation measures, such as the use of wind energy and hydroelectric generation potential. In general, actions on adaptation can often come with the benefit of supporting mitigation efforts. For example, trees planted to address the adaptation issue of soil erosion also act as a carbon sink and thereby contribute to mitigation.

Oceans play an important role in climate change, as they absorb carbon dioxide through physical, chemical and biological processes. As a result, they have taken up at least half of all man-made emissions of carbon dioxide. But there is evidence that the oceans may be starting to acidify. If this leads to a reduction of the oceans' carbon sink capacity, there will be more carbon dioxide staying in the atmosphere and hence more climate change. Further understanding of the role of oceans in climate change is essential.

The climate system is known to exhibit "tipping points," where change can be large, rapid and possibly irreversible. Scientific knowledge is at a preliminary stage when it comes to what changes in levels of GHGs might cause these "tipping points" to occur.

For example, the Greenland ice sheet is expected to start to decline once local warming reaches a certain stage; once started, such a deglaciation may be irreversible, bringing with it eventual sea level rise of several metres. Scientific knowledge, while incomplete, is sufficient to indicate the possibility of these "tipping points" that we should strive to avoid. Further work is required to better identify these thresholds.

Canada is already experiencing the affects of global climate change and incurring costs to adapt to it. While efforts to move towards stabilization of atmospheric concentrations of GHGs through emission reductions are important and necessary, it is also recognized that the rate and magnitude of climate change will continue to demand social adaptation strategies to minimize the risks to quality of life.

More than half of Canada's GDP is substantially affected by climate and weather, including forestry, agriculture, fishing, hydro-electricity generation, transportation and tourism. Climate change is affecting entire sectors and regional economies. It also contributes to extreme weather events that are even affecting the safety and security of Canadians. The Maritimes have experienced "once-in-a-hundred-year" storms in each of the last three years. The 1998 ice storm did more than $1 billion in damage and left more than 1.5 million Canadians without power. The cost of weather-related disasters grew five-fold during the 1990s to $2.5 billion per year.

The federal science and adaptation agenda could consist of the following components:

- **Increase Knowledge and Understanding**: A solid knowledge base is needed to increase our understanding of current and future trends relating to climate change and its impacts on Canada. A research agenda would address issues such as the impact of climate change on Canada's freshwater and marine resources and the key role that oceans play as a major GHG sink. The agenda could also include work to further our understanding of the existing vulnerability of Canadians, including specific population groups and regions (eg., residents living in Canada's north, due to the impacts of climate change on key sectors such as agriculture, transport, forestry, fisheries and oceans, tourism, infrastructure and human health and well-being.
- **Enhancing Awareness and Engagement**: The federal government will pursue engagement with other orders of government, universities, industry and communities in understanding climate change and developing holistic responses to climate change threats.
- **Developing Appropriate Adaptation Tools**: The impacts of climate change are far-reaching and have major implications for governments in terms of the relevancy and adequacy of existing policies and regulations. Comprehensive risk assessments could play a critical part in ensuring that the governments have a solid understanding of climate change-related risks on operations and planning. It will be important for the governments to clearly identify liability issues.

Technology

As noted previously, Budget 2005 announced the Government's plan to develop, by the end of 2006, a Sustainable Energy Science and Technology Strategy. To initiate the development of this strategy, a panel of experts will be appointed — to provide advice on priorities, taking into consideration our national energy circumstances, existing technology strengths, and opportunities for partnerships with the provinces, territories, industry and academia, as well as internationally. The panel will be asked to report on its findings in a time frame that will allow the Government of Canada to complete the development of the strategy in 2006. Key objectives of the strategy will be to:

> More than half of Canada's GDP is substantially affected by climate and weather, including forestry, agriculture, fishing, hydro-electricity generation, transportation and tourism.

- lever both the ideas and financial resources of the private sector, universities, provinces and territories;
- develop a set of medium-term research goals around the efficient production and use of conventional and renewable energy; and
- develop a detailed action plan for reaching these goals.

Organizations such as Sustainable Development Technology Canada, a not-for-profit foundation, support the development and demonstration of clean technologies which provide solutions to issues of climate change, clean air, water quality and soil, and which deliver economic, environmental and health benefits to Canadians. Technology advancement that facilitates GHG reduction initiatives will provide opportunities to improve the health of Canadians by contributing to more sustainable and liveable communities which are supportive of healthy lifestyles. In moving forward on climate change, we must ensure that the health impacts of new technologies or other mitigation measures are assessed before they are widely deployed or commercialized.

There is a need to develop a federal framework or mechanism to ensure health impacts of new technologies or other mitigation measures are assessed before they are widely deployed or commercialized. As the Government of Canada moves forward with the design of specific initiatives it should be based on an analysis of the benefits and costs of new technologies or processes introduced to reduce GHG emissions. Full knowledge of the health co-benefits will also go a long way in helping to mobilize Canadians and stakeholders in working towards the reduction targets.

Canada will host the Montreal Conference on Climate from November 28 to December 9, 2005, at which the nations of the world will begin consideration of the longer term global climate change regime.

Post-Kyoto

In moving beyond the Kyoto time-frame, the recent mandate given by the Prime Minister to the National Round Table on the Environment and the Economy (NRTEE) is significant. Among other items, the Prime Minister asked the NRTEE to develop advice on a long-term strategic energy and climate change policy for Canada that:

- sets the course for the 21st Century economy to 2030–2050;
- positions Canada to compete in a carbon-constrained world, including business and sub-national government opportunities, and options for aligning our policies and incentives to advance Canada to a position of leadership in renewable energy, efficiency and conservation; and
- considers options for post-2012 greenhouse gas reduction targets, including the second commitment period and beyond to 2050–2080, in keeping with objectives aimed at stabilizing concentrations of greenhouse gases in the atmosphere and minimizing temperature increases. In considering options the NRTEE will assess, among others, approaches taken by the United Kingdom and Japan.

International Strategy

Canada will host the Montreal Conference on Climate from November 28 to December 9, 2005, at which the nations of the world will begin consideration of the longer term global climate change regime. It is because of the importance of this regime for the world and for Canada that the Government decided to host the Montreal Conference on Climate. It is our intention to use our role as host and president of this meeting to do everything possible to successfully launch the constructive global dialogue that will shape the international agreement after 2012.

More than 180 countries will attend the Montreal Conference on Climate. Each faces its own unique challenges in reducing GHG emissions and adapting to the changing climate while ensuring its economy grows and prospers to improve the quality of life for its people. In order to facilitate the world's search for the best path forward, Canada will spend the coming months reaching out to countries around the world and learning about their perspectives and concerns first-hand.

The Government will also draw heavily on the advice and expertise that resides here in Canada. We will consult closely with provincial and territorial governments and Aboriginal peoples. We will seek the views of industry stakeholders and non-governmental organizations. The actions and perspectives of municipal governments will be taken into consideration.

How the world responds to climate change will significantly influence Canada's long-term competitiveness and the health and safety of Canadians. The new international agreement must provide the framework to drive prosperous 21st century economies that are innovative and efficient as well as lead to deeper reductions in GHG emissions.

The agreement must meet six key objectives. It must:

- have broader participation with fair goals, including all industrialized and key emerging economies;
- generate outcomes that will result in real progress over the longer term;
- provide incentives to invest in developing and sharing transformative environmental technologies to reduce emissions at home and abroad;
- maximize the deployment of existing clean technologies;
- support a streamlined and efficient global carbon market; and,
- address adaptation as well as mitigation.

Canada is well positioned to help build the optimal next-generation international agreement. We are a member of the G-8, La Francophonie, the Commonwealth, the North American Free Trade Agreement, the Organization of American States, the Arctic council and Asia Pacific Economic Cooperation. We have close ties with the United States, and we are respected in the developing world.

Environmental sustainability is also a priority in Canada's development cooperation. It will be systematically integrated into decision-making across all programming. Canada will assist countries to create, maintain and enhance environmental sustainability, particularly in relation to climate change, as well as the other key areas of land degradation, freshwater and sanitation, and urbanization.

Through the renewal of the Canada Climate Change Development Fund, Canada will continue to work very closely with developing countries to reduce the causes and adapt to the consequences of climate change. The Fund provides support to developing countries in four program areas: core capacity-building for Clean Development Mechanism participation, emission reduction, carbon sequestration, and adaptation. Our capacity-building efforts will help to increase foreign direct investments from private sources. We will also work with developing countries in determining how we could more effectively improve components of the Clean Development Mechanism.

Canada also supports a number of multilateral programs, including the Global Environment Facility (GEF), the main funding mechanism to help developing countries with their climate change-related activities, as well as ongoing programs of the United Nations Development Programme (UNDP), United Nations Environment Programme (UNEP), and regional development banks, including the World Bank's portfolio of Carbon Funds, to help leverage additional private sector investments.

Moving Forward on Climate Change

The Government of Canada is committed to reducing our GHG emissions in both the short-term and the longer term. This Plan sets out the framework and concrete actions for achieving these goals.

Meeting these objectives helps safeguard vulnerable ecosystems such as Canada's North, enhances our quality of life through health and other benefits and provides an opportunity to transform our economy. This Plan will enable Canadians to shift our country towards a clean energy future and increase the efficiency, sustainability and international competitiveness of the Canadian economy.

The Government is committed to providing resources and to working in partnership with Canada's provinces and territories, Aboriginal peoples, industry, environmental groups and others to implement the Plan.

How the world responds to climate change will significantly influence Canada's long-term competitiveness and the health and safety of Canadians.

Annex 1: **Summary of Potential Emission Reductions and Associated Federal Costs**

It is estimated that the approaches outlined in the Plan could reduce emissions by about 270 Mt annually in the 2008–2012 period. The associated federal investment is in the range of $10 billion, including $2 billion in funding for existing climate change programming. This investment would take place through the 2012 fiscal year, which encompasses eight budgets, including the 2005 budget.

There is an interdependency between the various mechanisms set out in Table 1, in particular the Climate Fund, Partnership Fund and Programs. For that reason, simply adding the high or low end of the Mt and $ ranges set out in Table 1 does not give an accurate representation of total emission reductions and costs.

Table 1

Element	Potential Cost to the Federal Government and Impact on Emissions
Climate Fund	Funding in the order of $4–5 billion could reduce emissions by 75–115 Mt annually in the 2008–2012 period. Budget 2005 provided a minimum $1 billion over five years.
Partnership Fund	Funding in the order of $2–3 billion could reduce emissions by about 55-85 Mt annually. Budget 2005 provided at least $250 million over five years, and indicated that funding could grow to $2–3 billion over the next decade.
Large Final Emitter System	The emission reduction target for the LFE system is set at 45 Mt off the revised baseline. Since LFEs can contribute up to 9 Mt to the GHG Technology Investment Fund, it is possible that 36 Mt would be generated in compliance against our Kyoto target.
Automobile Industry	The automobile industry has agreed to an emission reduction target of 5.3 Mt.
Renewable Energy	The initiatives for renewable energy found in Budget 2005 (WPPI, RPPI and tax incentives), combined with other initiatives such as supportive provincial actions, could yield emission reductions of about 15 Mt annually. Budget 2005 provided $297 million over five years and $1.8 billion over 15 years for WPPI and RPPI, and $295 million over five years in tax incentives. Extending the five year funding to 2012 could involve a total cost to Government of about $1 billion. Supplementary incentives through the offset system may be needed to deliver the 15 Mt.

Table 1 *(cont'd)*

Element	Potential Cost to the Federal Government and Impact on Emissions
One-Tonne Challenge	The One-Tonne Challenge set an emissions reduction goal for Canadians of 5 Mt. It is proposed that an additional $120 million be invested in the program to support that objective.
Greening Government	The emissions reduction goal for the federal government from its own operations is being set at 1 Mt, to be funded primarily through internal reallocation.
Programs	Extension of existing funding for climate change programs through 2012 could bring the cost to the federal government to about $2.8 billion. It is estimated that this level of funding could result in emission reductions of about 40 Mt annually in the 2008–2012 period. Budget 2005 notes that the $2 billion in program spending is subject to reallocation.
Business-as-Usual Sinks	The BAU agricultural sink is estimated at 10 Mt annually in the 2008–2012 period. The BAU forest sink is estimated to be in the range of 0–20 Mt.

Notes to Table 1:

1. The Partnership Fund figures include an estimated 20 Mt annually in total reductions from clean coal, carbon dioxide capture and storage and east-west transmission projects over the 2008–2012 period. The cost to the federal government is estimated at about $1.5 billion, or about 30 percent of the total cost for these energy large-scale projects.
2. In addition to the domestic reductions estimated to occur through the LFE system, automobile emission reductions, large scale energy projects, renewable energy, One-Tonne Challenge, greening government, programs and BAU sinks, it is estimated that further domestic emission reductions will be available through incremental agricultural and forest sinks, agricultural emission reductions, landfill gas and other reductions. These reductions could be delivered through the Partnership Fund and/or the Climate Fund; the cost to the federal government is estimated at $10 per tonne of carbon dioxide equivalent.
3. Where emission reductions other than those relating to large scale energy projects are being delivered through the Partnership Fund, the costing in this table assumes for analytical purposes that for every dollar invested by the federal government, provincial governments invest 67 cents.
4. Table 1 does not count any emission reductions from the *New Deal for Cities and Communities*, from existing and future investments in technology development or from any new tax measures that might result from the evaluation referred to in Budget 2005.
5. The costing of Table 1 assumes that international emission reductions are available at a cost of $10 per tonne of carbon dioxide equivalent; this is above the price at which many transactions are currently occurring, and is within the range of expert estimates for the 2008–2012 period.
6. Table 1 indicates the funding provided in Budget 2005 for the various elements of the Plan. The Budget Plan (p. 175) notes: "More action will be required in the future. The Government will introduce additional measures as resources permit and as we learn from our investments and international experience."

Annex 2: **Government Commitments to the Large Final Emitters**

Table 2

Government Commitments	2005 Plan
2002 Climate Change Plan for Canada	
55 Mt reduction target for 2008–2012	Fixed process emissions receive a 0 percent reduction target. Other emissions receive a 15 percent target subject to no sector target being greater than 12 percent.
Access to emissions trading, domestic offsets, and international permits	LFE companies can trade emission reductions that go beyond their regulated standard. They also have access to Clean Development Mechanism (CDM) and Joint Implementation (JI) credits, "greened" international permits (assigned amount units or AAUs) and domestic offsets.
Emissions-intensity approach	Emissions-intensity approach
Special provision for early action, competitiveness, capital stock turnover through covenants	Dealt with through target approach described above and emissions intensity targets.
Letter from Minister of Natural Resources Dhaliwal to Canadian Association of Petroleum Producers (CAPP), Dec. 2002	
$15 per tonne price cap	$15 per tonne price cap
Emission intensity targets for oil and gas sector will not be more than 15 percent below projected BAU emission intensity levels for 2010	Delivered through target approach described above
Letter from Prime Minister Chrétien to Canadian Association of Petroleum Producers (CAPP) July 2003	
Post-2012 emission reduction targets will not make Canadian oil and gas production uncompetitive, and industry will be consulted on the technical feasibility and economic impacts of targets for the period post-2012	Delivered through proposed approach to longer term target-setting.

Table 2 *(cont'd)*

Government Commitments	2005 Plan
The government will seek the most efficient means of implementing climate change policies, drawing on existing reporting and regulatory processes where appropriate; it will promote harmonized policies with a single efficient, federal-provincial/territorial harmonized reporting, verification and policy enforcement system where feasible	Proposed approach is based on maximizing efficiencies, using existing reporting and regulatory processes, and using provincial equivalencies where possible. A harmonized reporting and verification system with provinces and territories has been set up and a Phase 1 implementation stage is underway.
Equitable treatment of all sectors will continue to guide policy post-2012	Delivered through proposed approach to longer term target-setting.
The "business-as-usual" reference for intensity targets will take into account future federal environmental regulations so as to avoid imposing a "GHG penalty" on mandated actions to improve environmental performance	Will be reflected in regulations.
Emissions targets for new projects will be based on targets for existing best-practice facilities using similar technologies and will be locked in for up to ten years from first production	Targets for new large facilities will be based on best available technology economically achievable (BATEA); targets will be set in regulation, thereby providing maximum possible certainty.
Emissions below targets will generate credits that can be banked or transferred. Offset options will include: offsets generated by reductions in other facilities of the operator; qualifying domestic and international offsets; exercising the $15/tonne price assurance through 2012	Delivered through trading mechanism, domestic offset system and GHG Technology Investment Fund.
Methods will be developed to integrate into the compliance options an incentive to increase qualifying R&D to reduce carbon intensity	Delivered through Technology Investment Fund.
Costs incurred to comply with emission targets and that represent a cost to earned income will be treated consistently with other comparable operating and capital expenses by the tax system	Delivered through consistent tax treatment.

Annex 3:
Canada's Kyoto Commitment

Under the Kyoto Protocol, Canada has agreed to reduce its annual emissions over the period 2008–2012 to a level 6 percent below our actual emissions in 1990. Since our emissions in 1990 were about 596 Mt, this means that over the 2008–2012 period our emissions should not, on average, exceed 560 Mt. It is important to note that, in assessing whether Canada has met its target, account will be taken of the various flexibility mechanisms built into the Kyoto Protocol, including the provisions relating to emissions trading and to carbon sinks.

Canada's target is the most challenging GHG emission reduction target among Kyoto signatories. Among Kyoto signatories, the percentage difference between projected BAU emissions in 2010 — what emissions would be in the absence of action to reduce them — and the Kyoto target is greatest for Canada.

Our emissions in 2010 would be about 36 percent above 1990 levels, or about 45 percent above our Kyoto target, in the absence of any action to reduce them. This clearly demonstrates the magnitude of our challenge, and in fact our projection of BAU emissions for 2010 is currently being revised upwards. Canada has an energy intensive economy due to a combination of factors that make it unique among industrialized countries: a cold climate, large distance between population centres, and Canada's resource-based economy. As well, Canada's economy has been growing — between 1990 and 2003, our GDP grew by 43 percent. Canada's emissions in 2003 were about 24 percent above 1990 levels.

Despite the challenge, the Government ratified the Kyoto Protocol because Canada recognizes the significant threat posed by climate change, has a strong multilateral tradition and believes we must share in the international effort to solve this global problem. Moreover, Canada recognizes the domestic environmental and economic benefit that being a party to the Protocol will deliver. The Government is committed to respecting our Kyoto commitment "*in a way that produces long-term and enduring results while maintaining a strong and growing economy*," as stated in the Speech from the Throne.

Annex 4:
Climate Change Science

The IPCC was established by United Nations agencies in 1988 to undertake periodic comprehensive assessments of the available scientific and socio-economic information on climate change and its impacts and on options for mitigating and adapting to the risks posed by climate change. To date, the IPCC has issued comprehensive assessments in 1990, 1996 and 2001. Preparation of these assessments is undertaken with the help of several thousand experts from around the world. Canadian experts have been substantively involved in each of the three assessments produced to date and are similarly making significant contributions to the preparation of the fourth assessment report, to be completed in 2007. The individual IPCC Working Group reports are based on an assessment of published, peer-reviewed technical literature available at the time of preparation of the reports.

Evolution in our understanding of the science of climate change can be viewed through the key scientific conclusions from the three IPCC assessments completed to date. In the First Assessment, completed in 1990, experts concluded that they were certain that emissions from human activities are substantially increasing the atmospheric concentrations of GHGs and that this will enhance the greenhouse effect and result in an additional warming of the Earth's surface. Climate models available at that time predicted under BAU scenarios a rate of increase of global mean temperature during the 21st century of 0.3 degrees Celsius per decade, with an uncertainty range of 0.2–0.5 degrees Celsius. The IPCC pointed out a number of uncertainties, including sources and sinks of GHGs and the role of clouds, oceans and polar ice sheets. The First Assessment was used as the basis for arriving at the Framework Convention on Climate Change.

The Second Assessment, completed in 1995, highlighted the considerable progress in understanding made since 1990. New findings included: GHGs have continued to increase; climate has changed over the past century; the balance of evidence suggests a discernible human influence on global climate; climate is expected to continue to change in the future; and there are still many uncertainties. The Second Assessment was endorsed at the second Conference of the Parties to the Kyoto Protocol in 1996 and used as a basis for international negotiations around the Protocol.

The Third Assessment, completed in 2001, addressed the question of human influence on today's climate and what the possible future climate could be. Key findings included: an increasing body of observations gives a collective picture of a warming world and other changes in the climate system; emissions of GHGs due to human activities continue to alter the atmosphere in ways that are expected to continue to alter the climate; confidence in the ability of climate models to project future climate has increased; there is new and stronger evidence that most of the warming over the last 50 years is attributable to human activities; atmospheric climate change will persist for many centuries; and further action is required to address remaining gaps in information and understanding.

The three IPCC assessments have provided a record of increasing knowledge of climate change over the past 15 years. This has included understanding of how the climate system functions, how climate is changing, what the causes are, what the human contribution is and what the impacts are. In addition, they show how our confidence in the tools, data and projections for the future has increased substantially. Taken together, they have provided an unprecedented global consensus on an environmental issue, and thus a sound base upon which to develop both national and international approaches to address the issue.

Annex 5: **A History of Our Climate Change Actions**

We have made considerable investments in climate science, which will help us better understand the nature of climate change, its impacts and enhance our capacity to adapt to those impacts.

Investments

Since 1998, the Government has made incremental investments in climate change through successive budgets. Prior to Budget 2005, $3.7 billion had been set aside for climate change. Of this amount, about $2 billion remains to be used in coming fiscal years. This means that about $1.7 billion has been spent on climate change through the seven budgets since Kyoto was agreed upon in December 1997.

Of this $1.7 billion, about $900 million has been invested in reducing emissions during the Kyoto time period of 2008–2012. Of the remainder, some has been invested in the development of technologies that may bear some fruit in the Kyoto period but are likely to make their greatest contribution to reducing emissions after 2012. These investments will be critical in placing Canada on the lower-emissions trajectory that will be needed as the international community comes to terms with the very significant cuts in GHG emissions that are needed over time in order to address climate change.

We have made considerable investments in climate science, which will help us better understand the nature of climate change and its impacts and enhance our capacity to adapt to those impacts. Additionally, some funds have been invested in helping developing countries to reduce their emissions and maximizing opportunities for Canadian business to participate in the emerging international carbon marketplace by selling their technologies and expertise.

Measures Already in Place

The first tranche of actions to reduce emissions was contained in Action Plan 2000, which comprised a suite of measures that targeted key sectors accounting for 90 percent of Canada's GHG emissions:

- Measures implemented in the transportation sector included the Urban Transportation Showcase Program, which demonstrated the potential of innovative, integrated and sustainable transportation practices in our cities; and negotiation of voluntary agreements with air, rail, truck and marine sectors to improve fuel efficiency of goods transport.
- Measures in the building sector included energy efficiency evaluations for homeowners and improved energy efficiency standards for equipment and appliances.
- Measures in the area of renewable energy and cleaner fossil fuels included a federal green power procurement program, and promotion of carbon dioxide capture and storage.
- For small and medium-sized enterprises, measures included support for energy audits.
- Measures promoted agricultural sinks through the Greencover component of the Agricultural Policy Framework. The Pilot Emission Removals, Reductions and Learnings program has improved our understanding of how market-based initiatives can play an important role in reducing emissions and promoting carbon sinks.

In all, 45 different measures were included in Action Plan 2000.

The next major initiative was Budget 2001, which provided funding for the WPPI and the Green Municipal Funds. The WPPI represented a milestone in Canada's support for and implementation of emerging

renewable energy sources, while the Green Municipal Funds helped fund innovative emission reduction projects by our municipalities.

The *2002 Climate Change Plan for Canada* outlined a broad strategy to address climate change. Many parts of the 2002 Plan were funded in Budget 2003 and have built a solid foundation for further action. For example, to improve the efficiency of Canada's residential buildings, the EnerGuide for Houses Retrofit Incentive was launched in October 2003. This resulted in more than 100,000 EnerGuide home energy evaluations and approximately 15,000 grants awarded to homeowners who have made retrofits.

Early Signs of Progress

Canadian industry is now saving some $3 billion a year, thanks to advanced energy management practices. Emissions from houses, buildings and manufacturing have been essentially flat since 1990, despite robust economic and population growth.

Overall energy efficiency has improved by 13 percent since 1990. This has resulted in energy costs in 2004 that were $12 billion lower than they would have been if these energy efficiency improvements had not taken place. A recent study by the International Energy Agency (IEA) ranked Canada in the top third among IEA member countries in improving energy efficiency, ahead of the United States, the United Kingdom and Japan.

To succeed in our efforts to respect our Kyoto commitment, we need to work in partnership and mobilize our resources in this national effort, recognizing the important actions that have already been taken and the extensive consultations that have taken place with provinces, territories, Aboriginal peoples and stakeholders over the last decade.

Annex 6:
Engaging Canadians

Provinces, territories, Aboriginal peoples and stakeholders will be engaged on key elements of the Plan in order to implement it in a timely fashion; we intend to make major on-the-ground implementation steps in all areas of the Plan before the end of 2005. Public engagement mechanisms will also be developed in the monitoring and reporting of progress.

- **LFE GHG Protocol**
  - Sets out how the LFE system could be implemented under CEPA 1999 — for consultations with provinces, territories, industry, Aboriginal peoples and stakeholders.

- **Climate Fund mandate**
  - Sets out proposed mandate for the Climate Fund — certain aspects for consultations with provinces, territories, industry, Aboriginal peoples and stakeholders.

- **The offset system rules**
  - Sets out the rules for the offset system, including criteria for qualifying offset credits — for consultations with provinces, territories, industry, Aboriginal peoples and stakeholders.

- **Partnerships with provinces and territories**
  - Sets out proposed mandate and implementation of the Partnership Fund, including links to MoU process — for consultations with provinces and territories.

- **The development of LFE regulation**
  - Launch collaborative process with provinces, territories, industry, environmental groups, Aboriginal peoples and other stakeholders on development of the LFE regulation.

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EXHIBIT C
TO TESTIMONY OF DOUG RUSSELL

CURRENT TO: JULY 4, 2005

Last changed: 30 June 2005

Canada
38th Parl., 1st Sess.
4 Oct. 2004 - present

CHAPTER: S.C. 2005, c. 30
SHORT TITLE: Budget Implementation Act, 2005
BILL: C-43 (Bill is 102 pp.; Exp. Notes 13 pp.)

FULL TITLE: An Act to implement certain provisions of the budget tabled in Parliament on February 23, 2005

TYPE: Government Bill. Introduced by R. Goodale (Minister of Finance).

CURRENT STATUS: Royal Assent June 29, 2005. Act partly in force on Royal Assent. See BELOW for details.

PURPOSE:
Part 1
- To amend the Income Tax Act and the Income Tax Application Rules to
  - increase the amount that Canadians can earn tax free;
  - increase the annual limits on contributions to tax-deferred retirement savings plans;
  - eliminate the foreign property limitations on tax-deferred retirement savings plans;
  - increase the Child Disability Benefit supplement to the Canada Child Tax Benefit;
  - allow for a longer period for the existence of and contributions to a Registered Education Savings Plan in certain circumstances where the plan beneficiary is eligible for the disability tax credit;
  - increase the maximum refundable medical expense supplement;
  - exclude emergency medical services vehicles from the standby charge;
  - extend to January 11, 2005 the date for charitable giving in respect of the 2004 taxation year for the tsunami relief effort;
  - eliminate the corporate surtax; and
  - extend the SR&ED tax incentives to SR&ED performed in Canada's exclusive economic zone;

Part 2
- To amend the Air Travellers Security Charge Act to reduce the air travellers security charge for domestic air travel to $5 for one-way travel and to $10 for round-trip

travel, for transborder air travel to $8.50 and for other international air travel to $17, applicable to air travel purchased on or after March 1, 2005.

Part 3

- To amend Part IX of the Excise Tax Act to extend the application of the 83 per cent rebate of the goods and services tax (GST) and the federal component of the harmonized sales tax (HST) to eligible charities and non-profit organizations in respect of the tax they pay on their purchases to provide exempt health care supplies similar to those traditionally provided in hospitals;
- To provide that a director of a corporation may, under certain conditions, be held liable not only for unremitted net GST/HST amounts, but also for GST/HST net tax refund amounts to which the corporation is not entitled;
- To allow, under strict conditions, the creation of a Web-based GST/HST registry to facilitate the verification of a supplier's registration by a registrant for the purposes of claiming input tax credits;

Part 4

- To amend Schedule I to the Excise Tax Act to phase out the excise tax on jewellery through a series of rate reductions over the next four years;

Part 5

- To amend the Federal-Provincial Fiscal Arrangements Act to authorize the Minister of Finance to pay funds to a trust established to provide the provinces with funding for the purpose of early learning and child care;

Part 6

- To authorize the Minister of Finance to pay funds to a trust established to provide the Territories with funding for the purpose of assisting them to achieve the goals of the Northern Strategy;

Part 7

- To amend the Auditor General Act to permit the Auditor General to conduct inquiries into and report on the affairs of certain corporations that have received at least $100,000,000 in funding from Her Majesty in right of Canada;
- To amend the Financial Administration Act to extend the application of financial management and control provisions in that Act to wholly-owned subsidiaries of parent Crown corporations and certain parent Crown corporations;

Part 8

- To authorize the payment of funds to various foundations, including the Federation of Canadian Municipalities for the purpose of providing funding to the Green Municipal Fund;

Part 9

- To amend the Asia-Pacific Foundation of Canada Act to focus the mandate of the Foundation, to modify its

governance structure, to establish qualifications for the appointment of the directors and the President, to impose a duty of care on the directors and the President and to require that the Foundation offer its services in both official languages;

- To specify the type of funds the Foundation may receive and the appropriate use of those funds and to require that those funds be invested in accordance with policies, standards and procedures established by the board. In addition, the provisions of the Act respecting auditing, annual reports and winding-up have been expanded;

Part 10

- To amend Part 1 of the Budget Implementation Act, 1998 to broaden the category of persons to whom the Canada Millennium Scholarship Foundation may grant scholarships and bursaries to include not only persons who are Canadian citizens or permanent residents of Canada within the meaning of subsection 2(1) of the Immigration and Refugee Protection Act but also persons who are protected persons within the meaning of subsection 95(2) of that Act, for example, Convention refugees;

Part 11

- To authorize the Minister of State (Infrastructure and Communities), pursuant to the initiative commonly known as "A New Deal for Cities and Communities", to make payments for the purpose of providing funding, in the fiscal year 2005-2006, to cities and communities for environmentally sustainable infrastructure initiatives, in accordance with agreements to be negotiated with provinces, territories and first nations;

Part 12

- To enact the Nova Scotia and Newfoundland and Labrador Additional Fiscal Equalization Offset Payments Act. The legislation will implement the arrangements of February 14, 2005 reached with Newfoundland and Labrador and Nova Scotia on offshore revenues. To do this, the legislation will
  - authorize the payment of equalization offset payments to Newfoundland and Labrador and Nova Scotia for 2004-05 to 2011-12, set out the conditions under which payments will be extended to any of fiscal years 2012-13 to 2019-20, and authorize payments for that period should those conditions be met;
  - set out the manner in which the offset payments are to be calculated;
  - authorize the making of a cash pre-payment in the amount of $2 billion in respect of the agreement with Newfoundland and Labrador and a cash pre-payment in the amount of $830 million in respect of the agreement with Nova Scotia; and
  - implement all other aspects of the agreements;
- Consequential amendments to the Budget Implementation Act, 2004 respecting offset payments to Nova Scotia will also be required to ensure that 100 per cent offset is being provided for in fiscal years 2004-05 and 2005-06;

Part 13

- To establish an Agency, to be called the Canada Emission Reduction Incentives Agency, to acquire greenhouse

emission reduction and removal credits on behalf of the Government of Canada;

Part 14

- To enact the Greenhouse Gas Technology Investment Fund Act;
- To establish an account in the accounts of Canada called the Greenhouse Gas Technology Investment Fund to which are to be charged amounts paid by the Minister of Natural Resources for the purpose of
  - research into, or the development or demonstration of, technologies or processes intended to reduce emissions of greenhouse gases from industrial sources or to remove greenhouse gases from the atmosphere in the course of an industrial operation; or
  - creating elements of the infrastructure that are necessary to support research into, or the development or demonstration of, those technologies or processes;
- To provide for the creation of technology investment units in respect of amounts that are contributed to Her Majesty for those purposes;

Part 15

- To amend the Canada Deposit Insurance Corporation Act to
  - increase the deposit insurance coverage limit for insurable deposits from $60,000 to $100,000;
  - repeal the authority of the Corporation to make by-laws respecting standards of sound business and financial practices for member institutions; and
  - provide that the deposits of a federal institution shall automatically be insured;

Part 16

- To amend the Canada Student Financial Assistance Act to provide for the termination of the obligations of certain borrowers in respect of student loans in the event of their death or if, as a result of their permanent disability, they are unable to repay their loan without exceptional hardship, taking into account their family income;

Part 17

- To amend the Currency Act with respect to the Exchange Fund Account and the management of Canada's foreign exchange reserves. These amendments include authorizing the Minister of Finance to establish a policy concerning the investment of assets held in that Account and to advance funds to that Account on terms and conditions that the Minister considers appropriate;

Part 18

- To amend the Department of Public Works and Government Services Act to provide the Minister of Public Works and Government Services with responsibility for the procurement of goods and services for the federal government, and to authorize the Minister to negotiate and enter into contracts on behalf of the Government of Canada and to make commitments to a minimum volume of purchases on its behalf;

Part 19

- To amend the Employment Insurance Act and the Department of Human Resources Development Act to allow the Canada Employment Insurance Commission to set the premium rate

under a new rate-setting mechanism. In setting the rate, the Commission will take into account the principle that the premium rate should generate just enough premium revenue to cover payments to be made for that year, as well as the report from the employment insurance chief actuary and any public input. On an as-needed basis, the Commission may also contract for the services of persons with specialized knowledge in rate-setting matters. If it is in the public interest to do so, the Governor in Council may substitute a different premium rate. In any given year, the rate cannot change by more than 0.15% ($0.15 per $100) from the previous year's rate, and for the years 2006 and 2007 must not exceed 1.95% ($1.95 per $100);

Part 20

- To amend the Employment Insurance Act, for the purpose of the implementation of a premium reduction agreement between the Government of Canada and a province, to allow for a regulatory scheme to make the necessary adjustments and modifications to that Act as required to harmonize it with a provincial law that has the effect of reducing or eliminating the special benefits payable under that Act. A consequential change is also made to the parental benefits provisions;

Part 21

- To amend the Financial Administration Act to provide the authority for the President of the Treasury Board to create a shared-governance corporate entity for the purpose of administering group insurance or other benefit programs;
- To provide the authority for the Treasury Board to establish or modify those programs not just for employees of the public service but for other persons or classes of persons as well;

Part 22

- To amend the Old Age Security Act to increase the guaranteed income supplement by $18 a month for single pensioners and by $14.50 a month for each pensioner in a couple, effective January 2006. Also, the amendments increase the allowance by $14.50 a month and the allowance for the survivor by $18 a month, effective January 2006;
- To provide for identical increases to the guaranteed income supplement, the allowance and the allowance for the survivor in January 2007; and

Part 23

- To authorize the Minister of Finance to pay funds directly to the provinces of Quebec, British Columbia and Saskatchewan and to each of the three Territories.

1st Reading: Introduced, read and printed March 24, 2005.

2nd Reading: Debated April 12, 13, 15, and 22, May 17 and 18, 2005. Debated, read and referred to committee May 19, 2005.

Committee: Finance

Report: Reported with amendments June 8, 2005 (Sessional Paper No. 8510-381-151). Debated June 10 and 13, 2005. Concurred in with further amendments June 14, 2005.

3rd Reading: Debated June 15, 2005. Read and passed June 16, 2005.

Senate:

1st Reading:	Read June 16, 2005.
2nd Reading:	Debated June 20, 2005. Debated, read and referred to committee June 21, 2005.
Committee:	National Finance
Report:	Reported without amendment June 28, 2005.
3rd Reading:	Read and passed June 28, 2005.

Royal Assent: June 29, 2005

In force: -- Sections 1 to 20, 22 to 24, 27 and 28, 30 to 49, 52 to 80, 82 to 86, 110 to 112, 126 to 128, 130 to 133 and 136 to 143 in force on Royal Assent;

-- Section 25 deemed in force February 24, 2005 (Act, s. 25(2));
-- Section 26 in force March 1, 2009 (Act, s. 26(2));
-- Sections 87 to 92 require proclamation (Act, s. 95);
-- Section 96 requires proclamation (Act, s. 97);
-- Sections 98 to 100 and 104 to 107 require proclamation (Act, s. 109 (1));
-- Sections 101 to 103 and 108 deemed in force February 23, 2005 (Act, s. 109(2));
-- Sections 113 to 118 require proclamation (Act, s. 119);
-- Sections 120 to 124 require proclamation (Act, s. 125);
-- Sections 21, 29, 50, 51, 81, 93, 94, 129, 134 and 135 are coordinating amendments and are in force subject to conditions being fulfilled.

Acts affected:

Access to Information Act, R.S.C. 1985, c. A-1.
Air Travellers Security Charge Act, S.C. 2002, c. 9.
Asia-Pacific Foundation of Canada Act, R.S.C. 1985, c. A-13.
Auditor General Act, R.S.C. 1985, c. A-17.
Budget Implementation Act, 1998, S.C. 1998, c. 21.
Budget Implementation Act, 2004, S.C. 2005, c. 22.
Broadcasting Act, S.C. 1991, c. 11.
Canada Deposit Insurance Corporation Act, R.S.C. 1985, c. C-3.
Canada Post Corporation Act, R.S.C. 1985, c. 10.
Canada Student Financial Assistance Act, S.C. 1994, c. 28.
Canadian Environmental Protection Act, 1999, S.C. 1999, c. 33.
Currency Act, R.S.C. 1985, c. C-52.
Department of Human Resources Development Act, S.C. 1996, c. 11.
Department of Public Works and Government Services Act, S.C. 1996, c. 16.
Employment Insurance Act, S.C. 1996, c. 23.

Excise Tax Act, R.S.C. 1985, c. E-15.
Federal-Provincial Fiscal Arrangements Act, R.S.C. 1985, F-8.
Financial Administration Act, R.S.C. 1985, c. F-11.
Income Tax Act, R.S.C. 1985, c. 1 (5th Supp.)
Income Tax Application Rules, R.S.C. 1985, c. 2 (5th Supp.).
Old Age Security Act, R.S.C. 1985, c. O-9.
Privacy Act, R.S.C. 1985, c. P-21.
Public Sector Pension Investment Board Act, S.C. 1999, c. 34.
Public Service Staff Relations Act, R.S.C. 1985, c. P-35.
Public Service Superannuation Act, R.S.C. 1985, c. P-36.

PART 13

CANADA EMISSION REDUCTION INCENTIVES AGENCY

CANADA EMISSION REDUCTION
INCENTIVES AGENCY ACT

87. The Canada Emission Reduction Incentives Agency Act is enacted as follows:

An Act to establish the Canada
Emission Reduction Incentives Agency

Preamble

Recognizing that the reduction or removal of greenhouse gases is necessary to fight climate change and can also result in cleaner air, achieve other environmental objectives and advance the competitiveness and efficiency of Canadian industry;

NOW, THEREFORE, Her Majesty, by and with the advice and consent of the Senate and House of Commons of Canada, enacts as follows:

SHORT TITLE

Short title

1. This Act may be cited as the Canada Emission Reduction Incentives Agency Act.

INTERPRETATION

Definitions

2. The following definitions apply in this Act.

"Agency"

"Agency" means the Canada Emission Reduction Incentives Agency established by section 4.

"compliance unit"

"compliance unit" means a compliance unit within the meaning of the Kyoto Protocol.

"eligible credit"

"eligible credit" means an eligible domestic credit or an eligible Kyoto unit.

"eligible domestic credit"

"eligible domestic credit" means a tradeable unit that is of an eligible class designated by order made under paragraph 3(a).

"eligible Kyoto unit"

"eligible Kyoto unit" means any compliance unit that is of an eligible class designated by order made under paragraph 3(b).

"greenhouse gas"

"greenhouse gas" means any gas listed in Annex A to the Kyoto Protocol.

"Kyoto Protocol"

"Kyoto Protocol" means the Kyoto Protocol to the United Nations Framework Convention on Climate Change done at Kyoto on December 11, 1997, and includes any decision related to the implementation of that protocol taken by the "Conference of the Parties serving as the Meeting of the Parties to the Kyoto Protocol", within the meaning of that protocol.

"Minister"

"Minister" means the Minister of the Environment.

INTERPRETATION

Interpretation

2.1 For greater certainty, nothing in this Act limits or affects, expressly or implicitly, the power of a province to provide incentives for the reduction or removal of greenhouse gases through the acquisition, on behalf of the province, before or after they are created, of eligible credits created as a result of the reduction or removal of those gases by any means established by the province.

DESIGNATIONS

Designations

3. The Minister may, for the purposes of this Act, by order, designate

(a) as an eligible class for the purposes of the definition "eligible domestic credit" in section 2, any class of tradeable units issued under any program or measure established under section 322 of the Canadian Environmental Protection Act, 1999 ; and

(b) as an eligible class for the purposes of the definition "eligible Kyoto unit" in section 2, any class of compliance unit.

ESTABLISHMENT OF AGENCY

Establishment

4. (1) There is established a body corporate called the Canada Emission Reduction Incentives Agency, which may exercise powers only as an agent of Her Majesty in right of Canada.

Climate Fund

(2) The expression "Climate Fund" may be used to refer to the Agency.

Minister responsible

5. (1) The Minister is responsible for and has the overall direction of the Agency.

Ministerial direction

(2) The Agency must comply with any general or special direction given by the Minister with reference to the carrying out of its object.

Minister's power of inquiry

(3) The Minister may inquire into any activity of the Agency and has access to any information under the Agency's control.

Delegation by Minister

(4) The Minister may delegate to any person any power, duty or function conferred on the Minister under this Act, except the power to make orders under section 3 and regulations under subsection 18(2) and the power to delegate under this subsection.

OBJECT

Object

6. The object of the Agency is to provide incentives for the reduction or removal of greenhouses gases through the acquisition, on behalf of the Government of Canada, of eligible credits created as a result of the reduction or removal of those gases.

ORGANIZATION AND HEAD OFFICE

Appointment of President

7. The Governor in Council shall appoint a President of the Agency to hold office during pleasure for a renewable term of up to five years.

President's powers

8. The President is chief executive officer of the Agency and has supervision over and direction of its work and staff.

Delegation by President

9. The President may delegate to any person any power, duty or function conferred on the President under this Act.

Remuneration

10. The President is to be paid the remuneration that is fixed by the Governor in Council.

Head office

11. The head office of the Agency is to be at the place in Canada that is designated by the Governor in Council.

ADVISORY BOARD

Appointment of members

12. (1) The Governor in Council shall appoint an advisory board of not more than 12 members to hold office during pleasure for a term of not more than three years, which term may be renewed for one or more further terms.

Role of advisory board

(2) The role of the advisory board is to advise the Minister on any matter within the object of the Agency, including

(a) the types of projects that are most likely to result in significant reductions of greenhouse gas emissions and advance the competitiveness and efficiency of Canadian industry; and

(b) market conditions relating to eligible domestic credits and eligible Kyoto units.

Representation

(3) The Governor in Council may appoint any person with relevant knowledge or expertise to the advisory board, including persons from the agriculture, energy and forest sectors, environmental groups or provincial or municipal governments, and persons with knowledge or expertise in the markets for domestic and international credits relating to reductions or removals of greenhouse gases.

Publication

(3.1) The Minister shall publish the advice given under subsection (2) within 30 days after receiving it from the advisory board.

Chairperson

(4) The Minister shall appoint one of the members as Chairperson of the advisory board.

Remuneration

(5) The members of the advisory board are to be paid, in connection with their work for the advisory board, the remuneration that may be fixed by the Governor in Council.

Travel, living and other expenses

(6) The members of the advisory board are entitled to be reimbursed, in accordance with Treasury Board directives, the travel, living and other expenses incurred in connection with their work for the advisory board while absent from their ordinary place of residence.

Meetings

(7) The Chairperson may determine the times and places at which the advisory board will meet, but it must meet at least four times a year.

EMPLOYEES

Employees

13. The employees that are necessary for the proper conduct of the work of the Agency are to be appointed in accordance with the Public Service Employment Act.

DUTIES AND POWERS OF THE AGENCY

Contracts and agreements

14. The Agency may enter into contracts and other agreements with any person in Canada or elsewhere, or with any organization or government, including an international organization or the government of a foreign state, in the name of Her Majesty in right of Canada or in its own name.

Legal proceedings

15. Actions, suits or other legal proceedings in respect of any right or obligation acquired or incurred by the Agency, whether in its own name or in the name of Her Majesty in right of Canada, may be brought or taken by or against the Agency in the name of the Agency in any court that would have jurisdiction if the Agency were not an agent of Her Majesty.

Procurement process

16. The Agency has the authority to acquire eligible credits through its own procurement process despite any provision of any other Act of Parliament.

Competitive process - eligible domestic credits

17. The Agency must use a competitive process to acquire eligible domestic credits to ensure the cost-effectiveness of the acquisition.

Competitive process - eligible
Kyoto units

18. (1) The Agency must use a competitive process to acquire eligible Kyoto units and must be satisfied that the acquisition of those units is of benefit to Canada, taking into account the factors specified in the regulations.

Regulations

(2) The Minister may make regulations specifying factors for the purposes of subsection (1).

Advance payment for eligible
domestic credits

19. (1) The Agency may, with the approval of the Treasury Board, make payments to acquire eligible domestic credits before they are created if the Agency exercises due diligence and

(a) the credits are to be created in relation to a project that meets criteria established by the Minister;

(b) the Minister is satisfied that it is reasonable to expect that the project will result in reductions or removals of greenhouse gases in the amounts anticipated in the agreement relating to the acquisition; and

(c) the agreement relating to the acquisition contains a provision requiring the repayment of the proportion of the amounts advanced for which no credits are received by the Agency.

Credits may be in relation
to less than anticipated total

(2) If the Agency makes payments to acquire eligible domestic credits before they are created, the amount of reductions or removals of greenhouse gases related to the credits being acquired may be less than or equal to the total amount of reductions or removals of greenhouse gases anticipated from the project for which the credits are created.

Credits to be recorded

20. After acquiring eligible credits in its own name, the Agency must, without delay, take the steps necessary to have them recorded in the name of Her Majesty in right of Canada in any database designated by the Minister.

Contracts with Her Majesty

21. The Agency may enter into contracts, agreements or other arrangements with Her Majesty as if it were not an agent of Her Majesty.

GENERAL

Accident compensation

22. The President and the members of the advisory board are deemed to be employees for the purposes of the Government Employees Compensation Act and to be employed in the public service of Canada for the purposes of any regulations made under section 9 of the Aeronautics Act.

CORPORATE BUSINESS PLAN

Corporate business plan

23. (1) As soon as possible after the Agency is established and every year after that, the Agency must submit a corporate business plan to the Minister for approval and the Minister must cause a copy of the plan to be tabled in each House of Parliament on any of the first fifteen days on which that House is sitting after the Minister approves the plan.

Contents of corporate business plan

(2) The corporate business plan must include a statement of

(a) the Agency's objectives for the next five years;

(b) the strategies that the Agency intends to use to achieve its objectives, including operational, financial and human resource strategies;

(c) the Agency's expected performance over that period; and

(d) the Agency's operating and capital budgets for each year of that period.

AUDIT

Annual audit

24. The Auditor General of Canada is the auditor for the Agency and must

(a) annually audit and provide an opinion to the Agency and the Minister on the financial statements of the Agency; and

(b) provide the Minister and the President with copies of reports of audits carried out under this section.

ANNUAL REPORT

Annual report

25. (1) The Agency must, before December 31 of each year following the Agency's first full year of operations, submit an annual report on the operations of the Agency for the preceding fiscal year to the Minister, and the Minister must cause a copy of the report to be tabled in each House of Parliament on any of the first fifteen days on which that House is sitting after the Minister receives it.

Form and contents

(2) The annual report must include

(a) the financial statements of the Agency, prepared in accordance with accounting principles consistent with those applied in preparing the Public Accounts referred to in section 64 of the Financial Administration Act, and the Auditor General of Canada's opinion on them;

(b) information about the Agency's performance with respect to the objectives established in the corporate business plan; and

(c) any other information that the Minister may require to be included in it.

CONSEQUENTIAL AMENDMENTS

R.S., c. A-1

Access to Information Act

88. Schedule I to the Access to Information Act is amended by adding the following in alphabetical order under the heading "Other Government Institutions":

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

R.S., c. F-11

Financial Administration Act

89. Schedule II to the Financial Administration Act is amended by adding the following in alphabetical order:

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

R.S., c. P-21

Privacy Act

90. The schedule to the Privacy Act is amended by adding the following in alphabetical order under the heading "Other Government Institutions":

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

R.S., c. P-35

Public Service Staff Relations Act

91. Part I of Schedule I to the Public Service Staff Relations Act is amended by adding the following in alphabetical order:

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

R.S., c. P-36

Public Service Superannuation Act

92. Part I of Schedule I to the Public Service Superannuation Act is amended by adding the following in alphabetical order:

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

COORDINATING AMENDMENTS

2003, c. 22

93. (1) On the later of the coming into force of section 87 of this Act and section 11 of the Public Service Modernization Act, chapter 22 of the Statutes of Canada, 2003 (in this section referred to as the "other Act"), Schedule IV to the Financial Administration Act is amended by adding the following in alphabetical order:

Canada Emission Reduction Incentives Agency Agence canadienne pour l'incitation à la réduction des émissions

(2) If section 11 of the other Act comes into force before section 91 of this Act, then, on the later of the day on which that section 11 comes into force and the day on which this Act receives royal assent, section 91 of this Act and the heading before it are repealed.

2003, c. 22

94. On the later of the coming into force of section 87 of this Act and section 224 of the Public Service Modernization Act, chapter 22 of the Statutes of Canada, 2003, section 22 of the English version of the Canada Emission Reduction Incentives Agency Act, as enacted by section 87 of this Act, is replaced by the following:

Accident compensation

22. The President and the members of the advisory board are deemed to be employees for the purposes of the Government Employees Compensation Act and to be employed in the federal public administration for the purposes of any regulations made under section 9 of the Aeronautics Act.

COMING INTO FORCE

Order in council

95. This Part, other than sections 93 and 94, comes into force on a day to be fixed by order of the Governor in Council.

PART 14

GREENHOUSE GAS TECHNOLOGY INVESTMENT FUND

GREENHOUSE GAS TECHNOLOGY INVESTMENT FUND ACT

96. The Greenhouse Gas Technology Investment Fund Act is enacted as follows:

An Act to establish the Greenhouse Gas
Technology Investment Fund for the reduction
of greenhouse gas emissions and the
removal of greenhouse gases from the atmosphere

SHORT TITLE

Short title

1. This Act may be cited as the Greenhouse Gas Technology Investment Fund Act.

INTERPRETATION

Definitions

2. The following definitions apply in this Act.

"eligible contributor"

"eligible contributor" means a person who is subject to requirements - set out in regulations made under any Act of Parliament - respecting emissions of greenhouse gas from industrial sources, other than a person who is a vehicle manufacturer.

"Fund"

"Fund" means the Greenhouse Gas Technology Investment Fund established in section 3.

"greenhouse gas"

"greenhouse gas" means any gas listed in Annex A to the Kyoto Protocol to the United Nations Framework Convention on Climate Change done at Kyoto on December 11, 1997, as amended from time to time, to the extent that the amendments are binding on Canada.

"Minister"

"Minister" means the Minister of Natural Resources.

"vehicle"

"vehicle" means any vehicle that is capable of being driven or drawn on roads by any means other than muscular power exclusively, but does not include any vehicle designed to run exclusively on rails.

GREENHOUSE GAS TECHNOLOGY INVESTMENT FUND

Establishment

3. There is established in the accounts of Canada an account to be known as the Greenhouse Gas Technology Investment Fund.

Amounts to be credited to Fund

4. There shall be paid into the Consolidated Revenue Fund and credited to the Fund

(a) all amounts contributed to Her Majesty in right of Canada by an eligible contributor for the purpose of

(i) research into, or the development or demonstration of, technologies or processes intended to reduce emissions of greenhouse gases from industrial sources or to remove greenhouse gases from the atmosphere in the course of an industrial operation, or

(ii) creating elements of the infrastructure that are necessary to support research into, or the development or demonstration of, those technologies or processes; and

(b) an amount representing interest of the balance from time to time to the credit of the account at the rate and calculated in the manner that the Governor in Council may, on the recommendation of the Minister of Finance, prescribe.

Amounts charged to Fund

5. There shall be charged to the Fund the amounts paid out under section 6.

GRANTS OR CONTRIBUTIONS

Power of Minister

6. (1) The Minister may, out of the Consolidated Revenue Fund, make grants or contributions in any amount that he or she considers appropriate for any purpose referred to in paragraph 4(a).

Matters to consider

(2) In making a grant or contribution, the Minister shall consider

(a) the competitiveness and efficiency of industry;

(b) the sustainable development of Canada's natural resources;

(c) the development of Canadian scientific and technological capabilities; and

(d) any recommendations made by the standing committee of the House of Commons that normally considers matters related to the environment.

Limitation

(3) No grant or contribution may be made in excess of the amount of the balance to the credit of the Fund.

ADVISORY BOARD

Appointment of members

7. (1) The Governor in Council shall appoint an advisory board of not more than 12 members to hold office during pleasure for a term of not more than three years, which term may be renewed for one or more further terms.

Role

(2) The role of the advisory board is to advise the Minister on any matter respecting the making of grants or contributions for any of the purposes referred to in paragraph 4 (a), including the types of projects that are most likely to result in significant reductions of greenhouse gas emissions and the matters referred to in paragraphs 6(2)(a) to (d).

Publication

(3) The Minister shall publish the advice given under subsection (2) within 30 days after receiving it from the advisory board.

Representation

(4) The Governor in Council may appoint any person with relevant knowledge or expertise to the advisory board, including persons from industry, institutions of learning and environmental groups.

Chairperson

(5) The Minister shall appoint one of the members as Chairperson of the advisory board.

Remuneration

(6) The members of the advisory board are to be paid, in connection with their work for the advisory board, the remuneration that may be fixed by the Governor in Council.

Travel, living and other expenses

(7) The members of the advisory board are entitled to be reimbursed, in accordance with Treasury Board directives, the travel, living and other expenses incurred in connection with their work for the advisory board while absent from their ordinary place of residence.

Meetings

(8) The Chairperson may determine the times and places at which the advisory board will meet, but it must meet at least once a year.

Accident compensation

(9) The members of the advisory board are deemed to be employees for the purposes of the Government Employees Compensation Act and to be employed in the federal public administration for the purposes of any regulations made under section 9 of the Aeronautics Act.

TECHNOLOGY INVESTMENT UNITS

Creation

8. (1) Subject to subsections (2) to (5), the Minister must create technology investment units in respect of contributions made by eligible contributors to Her Majesty in right of Canada or to any fund designated by the Minister for the purposes of this subsection, for any of the purposes referred to in paragraph 4(a).

Units to be recorded in database

(2) The technology investment units are to be created in respect of a contribution by an eligible contributor in a manner that allows them to be recorded in a database established in relation to the emission requirements applicable to the eligible contributor.

When creation of units may begin

(3) Technology investment units may be created only in respect of contributions made on or after January 1, 2008.

Regulations fixing contribution
rate and number of units

(4) Subject to subsection (5), the Governor in Council may, on the recommendation of the Minister of the Environment, make regulations

(a) fixing the amount that must be contributed for technology investment units to be created, or the manner of calculating that amount; and

(b) determining the maximum number of those units that may be created in any period specified in the regulations.

Restriction on contribution rate

(5) Until December 31, 2012, the maximum amount that may be contributed for a technology investment unit to be created may not be more than $15.

Use of units

(6) Technology investment units may only be used by the eligible contributor in respect of whom they were created and that eligible contributor may use them only in accordance with any regulations in force that govern the manner in which they may be used to meet requirements relating to emissions of greenhouse gases from industrial sources.

COMING INTO FORCE

Order in council

97. This Part comes into force on a day to be fixed by order of the Governor in Council.

EXHIBIT D
TO THE TESTIMONY OF DOUG RUSSELL

Minister
of Natural Resources Canada

Ministre
des Ressources naturelles Canada

Ottawa, Canada K1A 0E4

December 18, 2002

Mr. John Dielwart
Chairman
Canadian Association of Petroleum Producers
2100 - 350 7th Avenue South West
Calgary, Alberta T2P 3N9

Dear Mr. ~~Dielwart~~: John

Shortly after the World Summit on Sustainable Development in Johannesburg last September, the Prime Minister committed in a speech in Calgary to engaging in a process of consultations with large industrial emitters to address some very real and legitimate concerns that had been raised regarding the risks and implications of Kyoto for industry.

I have been very pleased to participate with you in this intensive process of consultations initiated by the Prime Minister. It is our belief that a strong economy is the essence of a strong society and a necessary precondition to meeting our social and environmental goals. We have listened carefully to the perspectives of industry and I believe that we have made very real progress toward providing industry and the investment community with the certainty they require to continue to invest and grow with confidence.

Through our work together, we were able to address key issues raised by industry representatives in *A Climate Change Plan for Canada* including a commitment to a covenants approach to large industrial emitters and assurances that those firms that have taken early action are not disadvantaged for having done so. The Plan also undertook to continue our work with industry, provincial and territorial governments and other stakeholders to addressing other outstanding issues. Earlier this month at a speech in Edmonton, the Prime Minister committed to provide certainty regarding the price and volume of emissions reductions that industry will be required to make as part of our climate change plan. I am therefore very pleased that I am able to make a specific commitment on both of these issues.

On the price of carbon credits, the Government will ensure that, during the first commitment period, Canadian companies will be able to meet their emission reduction responsibilities at a price no greater than $15 a tonne. The Government will work with industry and others to develop appropriate mechanisms to meet this commitment in a manner that is affordable to industry and responsible for all Canadians.

Canada

With respect to the volume of emissions, the Government will set the emissions intensity targets for the oil and gas sector at a level not more than 15 percent below projected business-as-usual levels for 2010.

The Government recognizes such clarity on the cost and volume issues is important for industry to be able to plan and make the investments which will create jobs and increase incomes for Canadians. In providing this clarity, we believe we have addressed a very significant concern for industry and set the stage for a cooperative approach to implementing Canada's Climate Change Plan.

I look forward to working with you and your members to this end in the coming months.

Yours sincerely,

The Honourable Herb Dhaliwal, P.C., M.P.

British Columbia Hydro and Power Authority
2005 Resource Expenditure and Acquisition Plan
British Columbia Utilities Commission
Project No. 3698388

DIRECT TESTIMONY OF TIM LESIUK

Q1. Please introduce yourself to the British Columbia Utilities Commission (Commission).

A. My name is Tim Lesiuk. I am the Senior Environmental Co-ordinator, Climate Change Management, for British Columbia Hydro and Power Authority (BC Hydro). I have held my present position since June 2004.

Q2. What are the subjects of your evidence?

A. First, I will discuss my qualifications and experience.

Second, I will describe how BC Hydro incorporated greenhouse gas (GHG) regulatory risk into the proposed “open call” to the private sector in fiscal 2006 (F2006 Call).

Qualifications and Experience

Q3. Please describe your professional qualifications and experience.

A. My education, qualifications and experience are discussed in my Curriculum Vitae, which is attached hereto and marked **Exhibit A**.

I am responsible for managing climate change and GHG issues for BC Hydro. In particular, I am responsible for BC Hydro's GHG management strategy and corporate GHG inventory. In my current capacity I have provided advice on the incorporation of GHG risks and benefits into BC Hydro's business activities.

Prior to June 2004, I was BC Hydro's Environmental Research Co-ordinator and Manager of GHG offsets from July 2001 to May 2004. In that position, I was responsible for developing BC Hydro's GHG offset acquisition strategy. From 1998 to June 2001 I worked for Centra Gas British Columbia (Centra), where I was responsible for Centra's GHG policy and management strategy. I have a Bachelor of Science in Biology from the University of Victoria.

Q4. Have you previously testified before the Commission?

A. No. However, I contributed to BC Hydro's GHG-related Information Request responses in several Commission proceedings, including Vancouver Island Generation Project, the 2004/05 to 2005/06 Revenue Requirements Application, the Call for Tenders for Capacity on Vancouver Island, and the 2005 Resource Expenditure and Acquisition Plan.

Incorporation of GHG Regulatory Risk into F2006 Call

Q5. Is it important for BC Hydro to consider the risk of increased costs from future GHG regulation in its proposed F2006 Call?

A Yes. I believe that it is highly likely that GHG emissions will be regulated within the Electricity Purchase Agreement (EPA) 15, 20, 25, 30, 35 or 40 year term horizons proposed by BC Hydro as part of the F2006 Call, and that it is essential for BC Hydro consider the potential costs of those regulations as part of its F2006 Call process.

Q6. Why do you believe that it is highly likely that GHG emissions will be regulated within the EPA term horizons?

A. There are several reasons. First, there are growing national, provincial and even regional actions being taken to address climate change. At the national level, Canada has ratified the Kyoto Protocol and has recently introduced its plan to meet Canadian Kyoto commitments entitled "Moving Forward on Climate Change: A Plan for Honouring Our Kyoto Commitment" (the 2005 Climate Change Plan). A copy of the 2005 Climate Change Plan is attached as Exhibit B to the Direct Testimony of Douglas Russell. The federal government recently began purchasing GHG offsets under the Pilot Emission Removals, Reductions and Learnings Initiative and reports 900,000 tonnes carbon dioxide equivalent (CO_2e) contracted and 600,000 tonnes CO_2e under negotiation with a third round of bids still to be announced. At the provincial level, British Columbia (BC) has introduced its plan to address climate change – “Weather, Climate and the Future: B.C.'s Plan” - which will guide BC's approach as it works with the federal government, industry, local government and individuals to address climate change. Furthermore, Alberta has recently introduced for consultation the elements of its proposed GHG regulatory regime.

Second, businesses and utilities are increasingly taking action to manage the financial risk of future GHG regulations. Several Canadian utilities have undertaken high profile efforts in recent years to explore the risks and mitigate the future costs of compliance with upcoming regulation. In August 2004, TransAlta Corporation (TransAlta) announced it had made the first Canadian purchase of Certified Emission Reductions under the Kyoto Protocol. The purchase of 1.75 million tonnes of GHG reductions from a hog production facility in Chile has anchored a long-standing leadership role for TransAlta in the development of international emissions trading. A growing number of international carbon funds and “buying pools” are entering the marketplace

driven by the opportunities for emissions trading brought on by the Kyoto Protocol and national-level regulations. The Direct Testimony of Richard Rosenzweig at pages 7-11 provides further information concerning actions taken by the investment community and U.S. electric utilities to address GHG regulatory risk.

Q7. How did BC Hydro consider the costs of possible future GHG regulations in its F2006 Call process?

A. As part of its analysis, BC Hydro reviewed several U.S. and Canadian jurisdictions to determine how other electric utilities incorporate GHG regulatory risk into their resource evaluation and procurement processes. The Direct Testimony of Richard Rosenzweig at pages 9-11 and the Direct Testimony of Mary Hemmingsen at page 16 and Exhibit F describes the various jurisdictions that BC Hydro reviewed as part of its consideration of incorporating GHG regulatory risk into the F2006 Call.

BC Hydro also retained GCSI-Natsource (Natsource) to generate scenarios and future price forecasts that matched BC Hydro's proposed EPA design options. BC Hydro selected Natsource for a variety of reasons. Natsource's emissions business possesses significant expertise in the areas of climate change and GHG emissions, renewable energy and air quality, and leverage the staff's commercial and policy experience and knowledge to help clients achieve their economic and environmental objectives. Natsource is an international company with considerable Canadian expertise and experience. Further details concerning Natsource in general, and the experience and qualifications of Richard Rosenzweig and Doug Russell, are found in the Direct Testimony of Richard Rosenzweig at pages 2-3 and the Direct Testimony of Doug Russell at page 2.

Q8. What potential GHG policy scenarios did BC Hydro consider in identifying GHG compliance costs?

A. In the report attached as Exhibit B to the Direct Testimony of Richard Rosenzweig (the Report), Natsource reviewed a number of studies and models that estimate potential future regulation and forecast future demand and supply of compliance products to arrive at cost forecasts of complying with potential future regulations to limit GHG emissions. Three scenarios were prepared to cover the potential future regulatory landscape for the 2012-2020 period:

1. Kyoto Protocol (KP) Continuation, no U.S./Canadian action. Under this scenario, the U.S. does not join a post-2012 international agreement and does not take action at the federal level to reduce GHG emissions, and as a

consequence Canada does not impose requirements that are more stringent than the requirements imposed to meet its KP obligations. Under this scenario, Natsource estimated a $19-$31 (CDN)[1] price range (per tonne) for GHG compliance instruments;

2. KP Plus, with U.S./Canada. In this scenario, developed countries, including the U.S. and Canada, agree to a post-2012 international agreement that imposes GHG emission limitations on the U.S. and Canada, and requires more stringent reductions that were agreed to in the KP initial commitment period of 2008-2012. Under this scenario, Natsource estimated a $37-$50 (CDN) price range (per tonne) for GHG compliance instruments;

3. KP Plus, with separate U.S./Canada flexible trading. Under this scenario, Canada and the U.S. do not join a post-2012 international agreement, and instead develop their own continental GHG program. Under this scenario, Natsource estimated a $25-$37 (CDN) price range (per tonne) for GHG compliance instruments.

Beyond 2020, an alternative to using economic model estimates is needed because of the variability in modeling so far out given the variety of pathways that could be followed to achieve climate change goals. Natsource undertook discussions with leading experts in economic modeling of climate change policy and arrived at an approach that may be used to synthesize price forecasts from 2020 to 2040. The recommended approach inflates the 2020 price forecasts by 5% on an annual basis. The result is a rough proxy that avoids the difficulties involved in trying to select a single forecast that accommodates the wide range of results generated by a variety of economic models. Further detail on these scenarios and price ranges is provided in the Report.

Q9. How did BC Hydro determine GHG costs from these different scenarios and price ranges?

A. BC Hydro considered the range of potential GHG compliance cost scenarios generated by Natsource, which are set out in Table 1 below, and examined the electricity price implications for three different GHG cost levels across the range of possible contract lengths and generating technologies.

[1] All price estimates were calculated by Natsource in the year 2001 $US, and then converted from $US to $CDN using an exchange rate of $1 US = $1.244 CDN. Natsource took the exchange rate from www.x-rates.com on 8 June 2005.

Table 1.
Three compliance cost scenarios for GHG regulation

Scenario	Description	Relevant Models	Forecast Price (2015)[2]
1	KP continuation, no U.S./no further Canadian action beyond existing 2005 Large Final Emitter plan	•Bernard et al estimates #1 and #2 ($13.68 and $41.05) •Nordhaus estimate #2 ($8.71)	$19.00 - $31.00
2	KP plus, with U.S. and Canada participating	•Bernard et al estimates #3 and #4 ($26.12 and $41.05) •Jakeman et al ($47.27) •Manne and Richels ($73.40) •McCracken ($51.00) •Kurosawa et al ($33.59) •Kainuma et al ($17.42) •Bernstein et al ($13.68) •McKibben et al ($14.93)	$37.00 - $50.00
3	KP plus with more stringent requirement, plus separate U.S./Canada program with less stringent targets than KP Plus	•No models with directly comparable scenarios found. •Closest was analysis done for McCain-Leiberman bill •MIT ($13.68) •US Department of Energy ($27.37)	$25.00 - $37.00

I believe that the following values (Canadian $ per tonne CO_2e):

2010	2015	2020	2025	2030	2035	2040	2045
$15.00	$25.00	$25.00	$32.00	$41.00	$52.00	$66.00	$85.00

selected by BC Hydro are consistent with potential GHG costs under plausible future GHG policy scenarios because: (1) for 2010, the $15 per tonne CO_2e Government of Canada price assurance is taken into account; (2) for 2015 and 2020, the low range estimate of the moderate scenario (Scenario 3) in the Report is used; and (3) for 2025 and beyond, Natsource's recommended 5% escalator is

[2] All price quotes in $CDN, per tonne CO_2e.

used. I also believe these values are conservative enough to adequately capture the potential risk to ratepayers of future GHG regulations.

Q10. Why did you select the low range of Natsource's Scenario 3 (the moderate scenario)?

A. There are several reasons why I believe that the low end of Natsource's Scenario 3 (the moderate scenario) provides a reasonable range for projected GHG compliance costs. First, I looked to U.S. utilities and the GHG value range they have incorporated into their resource planning. The low range of Natsource's Scenario 3 falls within and is consistent with U.S. electric utilities' GHG value range as identified in the Direct Testimony of Richard Rosenzweig at pages 9-11.

Second, I believe that BC Hydro, with its in-house experience in commodity trades, will be able to select a lower than average price forecast upon which to base the GHG evaluation adjustment because it will have the capacity to effectively hedge the long-term risks posed by the long-term EPAs contemplated in the F2006 Call. BC Hydro owns facilities that are expected to fall under federal GHG regulation and expects to purchase permits and offsets in the marketplace to meet regulatory requirements. BC Hydro is a relatively large entity with a sophisticated commodities trading subsidiary, Powerex Corp. (Powerex), both housing extensive portfolio management, risk management and commodities market experience. BC Hydro expects to employ its own and the experience of Powerex to meet the compliance requirements of its thermal resources in the same way Powerex currently manages gas supply for those resources and manages electricity trade for BC Hydro.

Q11. What do you believe a reasonable base assumption for a GHG evaluation adjuster would be?

A. BC Hydro created a levelized GHG compliance adjustment matrix based on compliance and transaction cost values and generated a table of GHG evaluation adjustment figures based on the generating facility's emission profile and anticipated regulatory scenarios as described in the Report. Based on my experience, and knowledge of emissions from conventional fossil fuel fired electricity generating technology, I believe that BC Hydro's selected GHG evaluation adjuster matrix reflects a reasonable surrogate for future potential GHG compliance costs for electricity generation facilities coming online after 2005 and before 2010. All projects contracted as part of the F2006 Call will be required to meet the federal "Best Available Technology Economically Achievable" (BATEA) standard once the regulation has been established for the

Electricity Sector by Environment Canada. BATEA is described further in the Direct Testimony of Doug Russell at page 9.

The Natsource scenarios give rise to a wide range of GHG costs. However, based on my 8 years of experience with climate change issues in the utility industry and my review of the status of potential Canadian GHG policy, it is my judgement that these values adequately capture the potential risk to ratepayers of future GHG regulations.

Table 2
GHG evaluation adjustment figures ($/MWh) based on generating facility GHG emissions intensity and contract term

	EPA Term					
	15	20	25	30	35	40
Emissions CO_2e t/MWh						
0.1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
0.2	$0.00	$0.00	$0.00	$0.00	$0.00	$1.00
0.3	$1.00	$2.00	$2.00	$2.00	$2.00	$3.00
0.4	$2.00	$2.00	$3.00	$3.00	$3.00	$3.00
0.5	$4.00	$5.00	$5.00	$6.00	$6.00	$7.00
0.6	$7.00	$7.00	$8.00	$8.00	$9.00	$10.00
0.7	$9.00	$10.00	$10.00	$11.00	$12.00	$13.00
0.8	$11.00	$12.00	$13.00	$14.00	$15.00	$16.00
0.9	$13.00	$14.00	$16.00	$17.00	$18.00	$20.00
1	$15.00	$17.00	$18.00	$20.00	$21.00	$23.00
1.1	$18.00	$19.00	$21.00	$23.00	$24.00	$26.00
1.2	$20.00	$22.00	$23.00	$25.00	$27.00	$29.00

Coal-fired electricity generating facilities commonly emit 0.8 to beyond 1.2 t CO_2e/MWh. Therefore, the GHG evaluation adjustment figure for a coal-fired generation project with an EPA of 25 years would range between $13.00 to $23.00, depending on the project's emission profile. Single cycle (SCGT) natural gas fired electricity generating facilities commonly emit 0.4 to 0.7 t CO_2e/MWh. The GHG evaluation adjustment figure for a SCGT project with an EPA of 25 years would range between $3.00 to $10.00, depending on the project's emission profile. Combined cycle (CCGT) natural gas fired turbine electricity generating facilities commonly emit 0.3 to 0.4 t CO_2e/MWh. The GHG evaluation adjustment figure for a CCGT project with an EPA of 25 years would range between $2.00 to $3.00, depending on the project's emission profile.

Q12. In generating the GHG evaluation adjuster matrix, did you incorporate the concept of a "safety valve"?

A. Yes. Several studies have pointed out the significant economic impact associated with high GHG compliance costs and the political reality of the concept of a GHG cost "safety valve".

The function of a "safety valve" is to effectively cap the upper bound of the potential GHG compliance cost at a specified level to ensure such costs do not threaten the viability or competitiveness of the overall economy. For example, the Government of Canada has committed to a $15 per tonne CO_2e price assurance for the first KP commitment period of 2008-2012. Further details concerning this $15 per tonne price assurance are found at page 8 of the Direct Testimony of Douglas Russell. In addition, the States of Oregon and Washington have introduced safety valves into their respective GHG regulations. However, it should be noted that the Oregon and Washington State safety valves have not been implemented in the context of a national programme. Further details concerning the Oregon and Washington State GHG regimes are found at pages 7-9 of the Direct Testimony of Richard Rosenzweig.

Q13. Does that conclude your evidence?

A. Yes.

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Professional Experience

Senior Environmental Coordinator, Climate Change Management
British Columbia Hydro and Power Authority,
Vancouver, BC June 2004 - Present
Manage climate change and greenhouse gas (GHG) issues for BC Hydro. Responsible for internal and external climate change policy, GHG management strategy, and corporate GHG inventory. Lead BC Hydro's advocacy and negotiation efforts with provincial and federal governments. Undertake research and monitoring activities concerning greenhouse gas market activity and trends and provide strategic advice on incorporating greenhouse gas risks and benefits in business activities.

Environmental Research Coordinator, Greenhouse Gas Offsets
British Columbia Hydro and Power Authority,
Vancouver, BC July 2001 - May 2004
Developed BC Hydro's international offset acquisition strategy, identifying projects and negotiating contracts to cover 5.5 million tonnes of GHG emissions through 2010 from two natural gas fired facilities proposed for Vancouver Island. Reviewed in excess of 300 offset project submissions from private entities, national governments and brokers. Led the negotiation of several significant contracts for CDM, JI, and domestic offsets to suit the desired portfolio design. Managed BC Hydro's interest in existing GHG offset contracts. Represented Canadian Electricity Association on Greenhouse Gas Emission Reduction Trading (GERT) Pilot project.

Environmental Specialist
Centra Gas British Columbia,
Victoria, BC 1998 – June 2001
Responsible for GHG policy and management strategy. Coordinated GHG management and policy with parent company Westcoast Energy. Led negotiations regarding GHG offset opportunities and, GHG inventory, leak detection and measurement. Provided community relations support for major project development. Managed environmental training and environmental field services, on-site monitoring and facility permitting/reporting.

Education

1999 Diploma of Technology in Environmental Science
Camosun College, Victoria, British Columbia

1993 Bachelor of Science, Biology
University of Victoria, Victoria, British Columbia